EB-2022-0200

Enbridge Gas Inc.
2024 Rebasing

POLLUTION PROBE
HEARING COMPENDIUM

ENBRIDGE GAS INC.

Answer to Interrogatory from
Pollution Probe (PP)

Interrogatory

Question(s):

a) Please provide examples of Enbridge customers that have made a commitment to move to natural gas with carbon capture.

b) Please explain who regulates hydrogen in Ontario and under what authority.

c) For the scenario including 100% hydrogen, please provide what responsibility and regulatory authority the OEB would have in regulating pure hydrogen production and/or infrastructure (e.g. hydrogen pipelines) in Ontario, if any.

Response:

a) Enbridge Gas has held discussions with several large volume customers on the potential for carbon capture; however, currently none have committed to move forward pending the development of further government regulations required to permit these activities within Ontario.

b) Hydrogen pipelines and facilities in Ontario fall under the jurisdiction of the Technical Standards and Safety Authority (TSSA). Depending on application, the applicable regulations are O. Reg. 210/01: Oil and Gas Pipeline Systems, O. Reg. 212/01: Gaseous Fuels, O. Reg. 220/01: Boilers and Pressure Vessel Regulation, or O. Reg. 219/01: Operating Engineers Regulation.

c) The OEB does not currently have a mandate to regulate 100% hydrogen. As provided at Exhibit 1, Tab 10, Schedule 6, par. 93, the Government of Ontario would have to implement an expanded mandate for the Ontario Energy Board to enable it to regulate hydrogen pipelines.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Pollution Probe (PP)

Interrogatory

Question(s):

Enbridge indicated that Phase 1 of the Low Carbon Energy Project (LCEP) is complete and that Phase 2 is in planning. Enbridge also indicates that an additional $8.9 million of system reinforcement costs are included in this application related to accommodating hydrogen blending.

a) Enbridge Gas estimates that the GHG reductions associated with using blended gas having 2% hydrogen by volume in the BGA would be between 97-120 tonnes of carbon dioxide equivalent (tCO2e) per year. [EB-2019-0294 Decision, page 1]. Please provide the actual annualized tonnes of carbon dioxide equivalent (tCO2e) avoided from the LCEP and provide the calculations used to determine the avoided emission compared to those if blending had not occurred.

b) Please provide the current (i.e. most recent) blending percentage rate and the average blending percent since the LCEP project was commissioned.

c) Enbridge Gas agreed with the reporting requirements proposed by OEB staff. Enbridge Gas agreed that some reporting will be appropriate in the context of the upcoming rebasing proceeding, providing the OEB and parties with interim information about the Project before full reporting is provided. Reporting on the ongoing customer communication is required to ensure that customers report on their experience with the blended gas and the performance of their equipment. The OEB makes these reporting commitments a condition of proceeding with the Project. [EB-2019-0294 Decision, page 14]. Given Enbridge is asking to accelerate Phase 2 of the project. Please provide a copy of the final report for Phase 1.

Response:

a) 2022 is the first full year for which GHG emissions savings can be calculated. The emissions savings from January 1, 2022, to December 31, 2022 are 86.30 tCO2e. Avoided emissions were deduced by calculating the avoided volume of natural gas due to hydrogen injection based on energy consumed by downstream network.

Emissions Avoided (tCO2e) = NG Avoided (m3) * 0.001932 (tCO2e/m3)

NG Avoided (m3) = Energy Consumed Equivalent in NG (m3) – Actual NG Consumed (m3)

b) A current blend rate cannot be provided as the plant blends at a variable rate which changes continuously up to 2% hydrogen. Since the LCEP was commissioned until January 2023, the blend percentage averaged 1.13%.

c) The OEB imposed several conditions related to the LCEP[1]One of those conditions was condition 2, which indicated that "After 5 years of operational experience, Enbridge Gas shall file a report with the OEB that, at a minimum, includes the following:"[2] Condition 2 goes on to list the items to be included in that report. As the pilot has just completed the first year of full operations (October 1, 2021, to October 1, 2022) a final report is not available, and cannot be produced until the pilot has run its course.

In the Low Carbon Energy Project[3] proceeding Enbridge Gas indicated that some reporting on the LCEP would be appropriate in the context of this Rebasing Application. Exhibit 4, Tab 2, Schedule 6, pages 12 to 14, provides an update on Phase 1 of the LCEP.

Further reporting will be provided in the context of the leave to construct application for LCEP phase 2, which Enbridge Gas expects to file with the OEB likely in late 2023 or early 2024.

[1] EB-2019-0294, Decision and Order, Schedule B, October 29, 2020.
[2] Ibid.
[3] EB-2019-0294.

ENBRIDGE GAS INC.

Answer to Undertaking from
Pollution Probe (PP)

Undertaking

Tr: 176

To provide the number of customers and the cost for the Low Carbon Energy Project, Phase 1

Response:

As provided at Exhibit 4, Tab 2, Schedule 6, page 13, at the time the Low-Carbon Energy Project, Phase 1 was put into service, the number of customers was approximately 3,600.

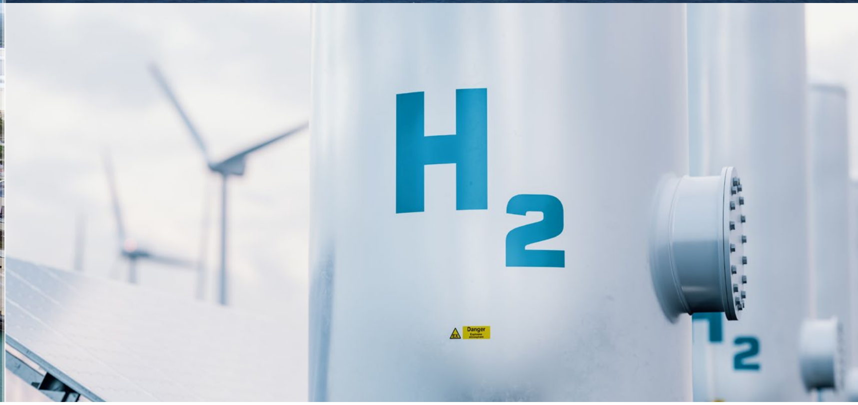
As provided in response at Exhibit I.2.5-VECC-17, the capital costs of the Low-Carbon Energy Project, Phase 1 inclusive of overhead allocations are $5,785,163 for 2021, and $152,382 for 2022. O&M costs were immaterial. Enbridge Gas anticipates that the project cost may be offset by grant funding of approximately $221,000, which is in progress.[1] Enbridge Gas will provide an updated response to Exhibit I.2.5-VECC-17, correcting the Table 1 units with the package of interrogatory response updates, currently expected on April 11, 2023.

[1] EB-2019-0294, Exhibit B, Tab 1, Schedule 1, p.16.

Bridge to a Cleaner Energy Future





Al Monaco
President &
Chief Executive Officer

Vern Yu
EVP, Corporate Development &
Chief Financial Officer

Q3 2022 Financial Results & Business Update

Legal Notice

Forward Looking Information

This presentation includes certain forward-looking statements and information (FLI) to provide potential investors and shareholders of Enbridge Inc. (Enbridge or the Company) with information about Enbridge and its subsidiaries and affiliates, including management's assessment of their future plans and operations, which FLI may not be appropriate for other purposes. FLI is typically identified by words such as "anticipate", "expect", "project", "estimate", "forecast", "plan", "intend", "target", "believe", "likely" and similar words suggesting future outcomes or statements regarding an outlook. All statements other than statements of historical fact may be FLI. In particular, this presentation contains FLI pertaining to, but not limited to, information with respect to the following: Enbridge's strategic plan, priorities and outlook; 2022 financial guidance, including projected DCF per share and adjusted EBITDA, and expected growth thereof; expected dividends, dividend growth and dividend policy; expected supply of, demand for, exports of and prices of crude oil, natural gas, natural gas liquids (NGL), liquified natural gas (LNG) and renewable energy; energy transition and low carbon energy, and our approach thereto; environmental, social and governance (ESG) engagement, commitments and disclosure, including the Regional Oilsands Indigenous partnership; industry and market conditions, including market risks, tailwinds and headwinds such as recession and inflation and interest rates; anticipated utilization of our assets; expected adjusted EBITDA; expected DCF and DCF per share; expected future cash flows; expected shareholder returns; expected performance of the Company's businesses, including customer growth and organic growth opportunities; financial strength, capacity and flexibility; financing costs(1); expected costs related to announced projects, projects under construction and system expansion, optimization and modernization; expected in-service dates for announced projects and projects under construction; expected capital expenditures; capital allocation framework and priorities; share repurchases under normal course issuer bid; expected future growth, including secured growth program, development opportunities and low carbon and new energies opportunities and strategy, including the T-North and T-South pipeline expansions, and the Gray Oak and Tri Global Energy acquisition; expected future actions of regulators and courts and the timing and anticipated impact thereof; toll and rate case proceedings and frameworks, including with respect to the Mainline, and anticipated timing and impact therefrom; and CEO transition. Although we believe that the FLI is reasonable based on the information available today and processes used to prepare it, such statements are not guarantees of future performance and you are cautioned against placing undue reliance on FLI. By its nature, FLI involves a variety of assumptions, which are based upon factors that may be difficult to predict and that may involve known and unknown risks and uncertainties and other factors which may cause actual results, levels of activity and achievements to differ materially from those expressed or implied by the FLI, including, but not limited to, the following: energy transition, including the drivers and pace thereof; global economic growth and trade; the expected supply of, demand for, exports of and prices of crude oil, natural gas, NGL, LNG and renewable energy; anticipated utilization of our assets; anticipated cost savings; exchange rates; inflation; interest rates; the COVID-19 pandemic and the duration and impact thereof; availability and price of labour and construction materials; the stability of our supply chain; operational reliability and performance; customer, regulatory and stakeholder support and approvals; anticipated construction and in-service dates; weather; announced and potential acquisition, disposition and other corporate transactions and projects, and the timing and impact thereof; expectations about our partners' ability to complete and finance proposed projects; governmental legislation; litigation; credit ratings; hedging program; expected EBITDA; expected future cash flows; expected future DCF and DCF per share; estimated future dividends; financial strength and flexibility; debt and equity market conditions; general economic and competitive conditions; the ability of management to execute key priorities; and the effectiveness of various actions resulting from the Company's strategic priorities. We caution that the foregoing list of factors is not exhaustive. Additional information about these and other assumptions, risks and uncertainties can be found in applicable filings with Canadian and U.S. securities regulators. Due to the interdependencies and correlation of these factors, as well as other factors, the impact of any one assumption, risk or uncertainty on FLI cannot be determined with certainty. Except to the extent required by applicable law, we assume no obligation to publicly update or revise any FLI made in this presentation or otherwise, whether as a result of new information, future events or otherwise. All FLI in this presentation and all subsequent FLI, whether written or oral, attributable to Enbridge, or any of its subsidiaries or affiliates, or persons acting on their behalf, are expressly qualified in its entirety by these cautionary statements.

1. As at September 30, 2022, approximately 10% of Enbridge's debt is exposed to floating interest rates as well as 2023 debt maturities that require re-financing which, given rising interest rates, has had and could continue to have an impact on our financing costs.

Non-GAAP and Other Financial Measures

This presentation makes reference to non-GAAP and other financial measures, including EBITDA, adjusted EBITDA, adjusted earnings, adjusted earnings per share, distributable cash flow (DCF) and DCF per share. Management believes the presentation of these metrics gives useful information to investors and shareholders as they provide increased transparency and insight into the performance of the Company. EBITDA represents earnings before interest, tax, depreciation and amortization. Adjusted EBITDA represents EBITDA adjusted for unusual, infrequent or other non-operating factors on both a consolidated and segmented basis. Management uses EBITDA and adjusted EBITDA to set targets and to assess the performance of the Company and its business units. Adjusted earnings represent earnings attributable to common shareholders adjusted for unusual, infrequent or other non-operating factors included in adjusted EBITDA, as well as adjustments for unusual, infrequent or other non-operating factors in respect of depreciation and amortization expense, interest expense, income taxes and noncontrolling interests on a consolidated basis. Management uses adjusted earnings as another measure of the Company's ability to generate earnings. DCF is defined as cash flow provided by operating activities before the impact of changes in operating assets and liabilities (including changes in environmental liabilities) less distributions to non-controlling interests, preference share dividends and maintenance capital expenditures, and further adjusted for unusual, infrequent or other non-operating factors. Management also uses DCF to assess the performance of the Company and to set its dividend payout target. Reconciliations of forward-looking non-GAAP and other financial measures to comparable GAAP measures are not available due to the challenges and impracticability of estimating certain items, particularly certain contingent liabilities and non-cash unrealized derivative fair value losses and gains which are subject to market variability. Because of those challenges, reconciliations of forward-looking non-GAAP and other financial measures are not available without unreasonable effort. Our non-GAAP metrics described above are not measures that have standardized meaning prescribed by generally accepted accounting principles in the United States of America (U.S. GAAP) and are not U.S. GAAP measures. Therefore, these measures may not be comparable with similar measures presented by other issuers. A reconciliation of historical non-GAAP and other financial measures to the most directly comparable GAAP measures is available on the Company's website. Additional information on non-GAAP and other financial measures may be found in the Company's earnings news releases or in additional information on the Company's website, www.sedar.com or www.sec.gov. Unless otherwise specified, all dollar amounts in this presentation are expressed in Canadian dollars, all references to "dollars" or "$" are to Canadian dollars and all references to "US$" are to US dollars.

Agenda

- Q3 Highlights
- Business Update
- Financial Performance & Outlook

Q3 Highlights

Operations	• Focused on operational safety and integrity programs • High capacity utilization across the business	
Financial	• Strong Q3 results; On track to achieve 2022 EBITDA & DCF/share guidance • Bolstering balance sheet flexibility	
Execution	• On track for $3.8B to enter service in 2022 • Placed Gulfstream Phase VI into service • St. Nazaire (offshore wind in France) expected in service in November	 New New
Growth	• Secured $3.8B in new organic investments • Acquired Tri Global Energy extending N.A. onshore renewable development • Acquired additional 10% interest in Cactus II Permian pipeline	New New New
Capital Recycling	• $1.12B sale in select Regional Oil Sands assets • Increased interest in Gray Oak pipeline; US$0.4B cash received	New New

Our Dual-Pronged Strategy

		Core Growth				Low-Carbon Growth		
		Optimize / Expand	Exports	Modernize Assets	Solar/ Wind	RNG[1]	H_2	CCS[2]
	Liquids Pipelines	✓	✓	✓	✓[3]		✓	✓
	Gas Transmission	✓	✓	✓	✓[3]	✓	✓	✓
	Gas Distribution	✓		✓		✓	✓	✓
	Renewable Power	✓		✓	✓		✓	

Our strategies focus on conventional <u>and</u> low-carbon growth opportunities

(1) RNG: Renewable Natural Gas (2) CCS: Carbon Capture & Sequestration (3) Solar self-power program

Business Update

Gas Transmission

- Advancing ~$10B capital program
- Gulfstream Phase VI in service **New**
- B.C. Pipeline rate settlement in principle **New**
- TETCO settlement awaiting FERC approval

Gas Distribution & Storage

- $3.5B utility growth capital program in execution
- Filed application to establish 2024-2028 rates **New**
- Sanctioned 2 new RNG projects **New**

Renewables

- $2.9B of growth capital in execution
- $1.1B projects to enter service in 2022
- 10 solar self-power projects in construction

Liquids Pipelines

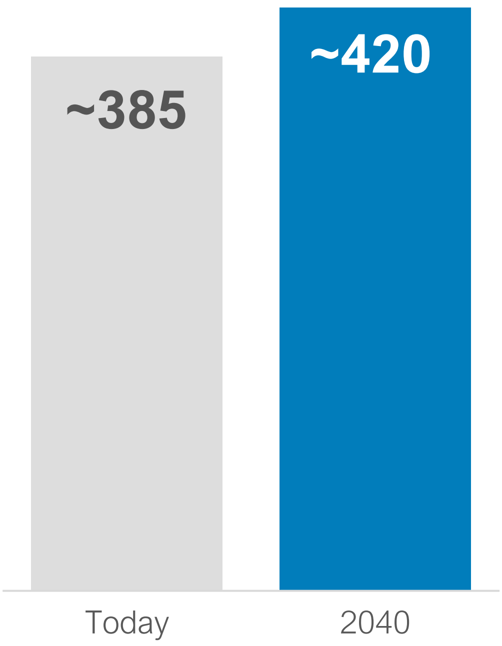
- Mainline volumes on track for average of 2.95 mmbpd[2]
- Advancing Wabamun Carbon Hub
  - Signed Carbon Evaluation Agreement with Gov't of AB **New**
- Progressing EIEC[3] Blue Ammonia & Sequestration Hub

Successfully executing on our strategies

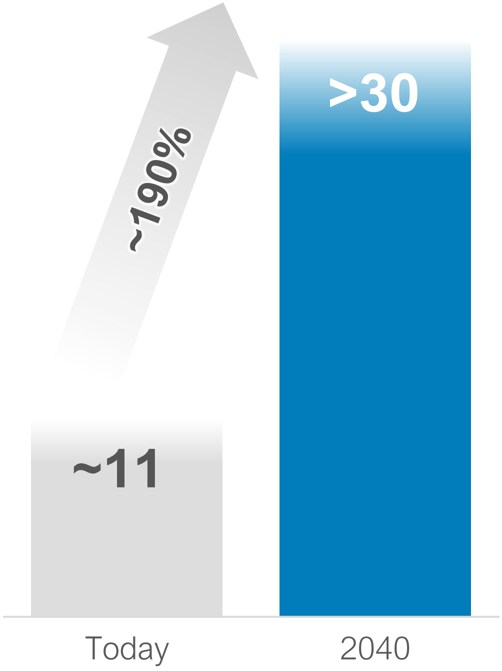
(1) Net capacity of assets in operation and under construction; (2) Average Ex-Gretna throughput for 2022; (3) Enbridge Ingleside Energy Center

Global Natural Gas Fundamentals

Growing Global Demand[1]
(Bcf/d)



Growing N.A. LNG Exports[1]
(Bcf/d)

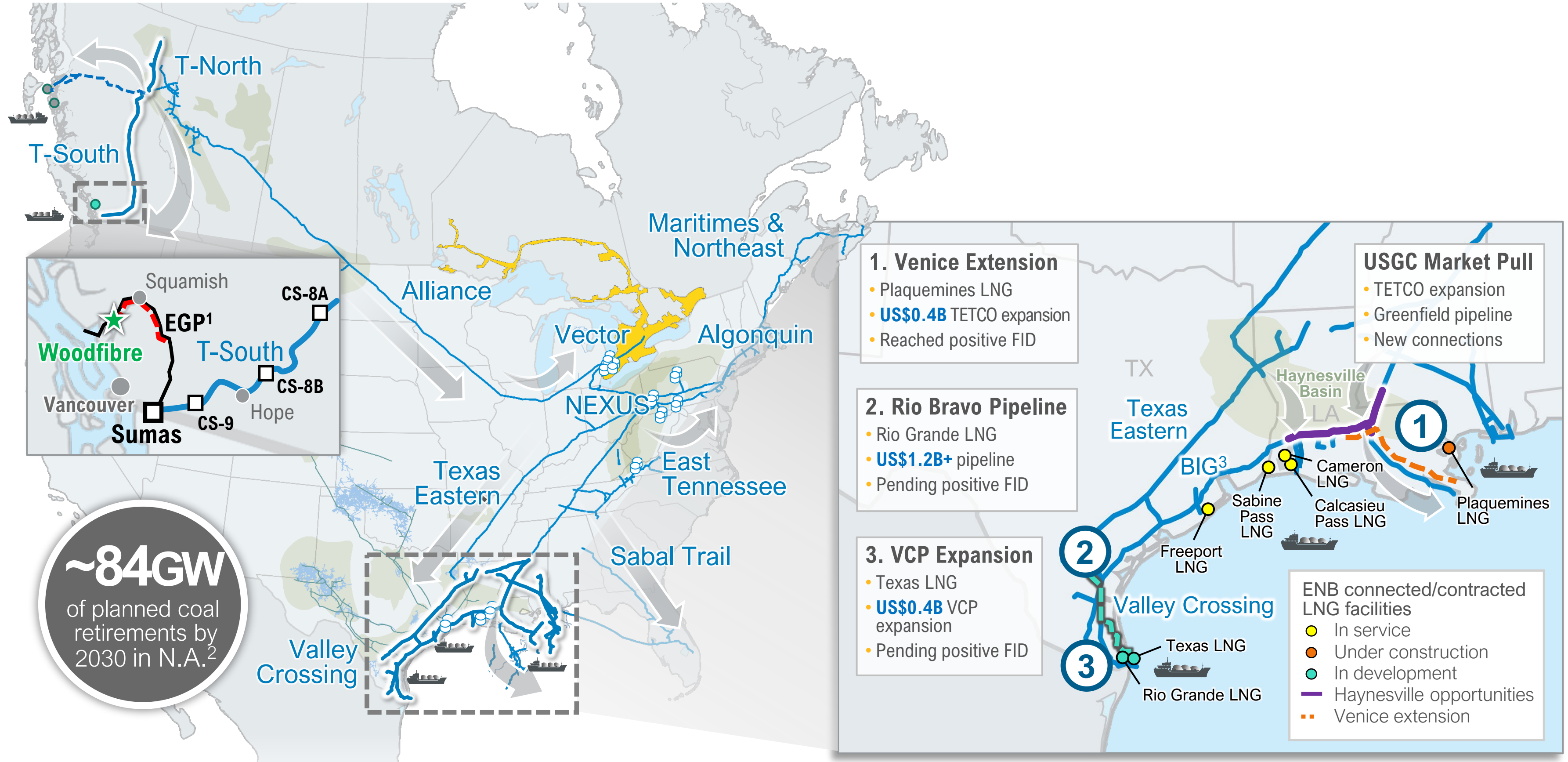


- Demand growth driven by security benefits, reliability of supply, and lower emissions
- Essential fuel for quality of life; stable part of the supply mix well into the future
- North America's gas advantage will lead to increased LNG market share through 2040

North American natural gas is critical to meeting rising global demand

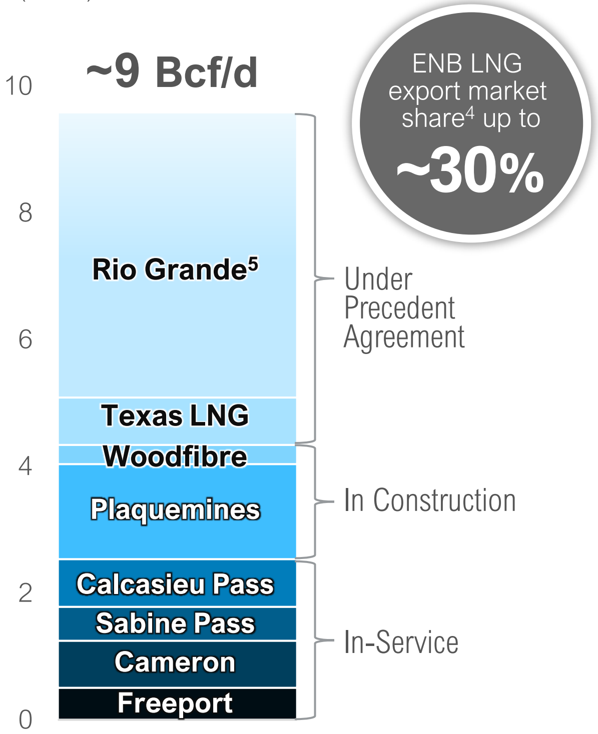
(1) Rystad Energy GasMarketCube, October 2022

Enbridge's Natural Gas Strategy



Potential Enbridge LNG Export Volumes[4]

(Bcf/d)



Well-positioned to capitalize on positive North American fundamentals

(1) Eagle Mountain Gas Pipeline – Fortis adding ~50 kilometers of new gas pipeline to existing Eagle Mountain Gas Pipeline to connect with Woodfibre (2) S&P Global Platts (3) Brazoria Interconnector Gas Pipeline
(4) Served by Enbridge natural gas pipelines; assumes ~30Bcf/d of N.A. LNG exports by 2040 (5) Rio Grande LNG phase 1 expected to bring 1.8 Bcf/d into production with full capacity potential of 4.5 Bcf/d

T-South Pipeline Expansion

Newly Secured Organic Project

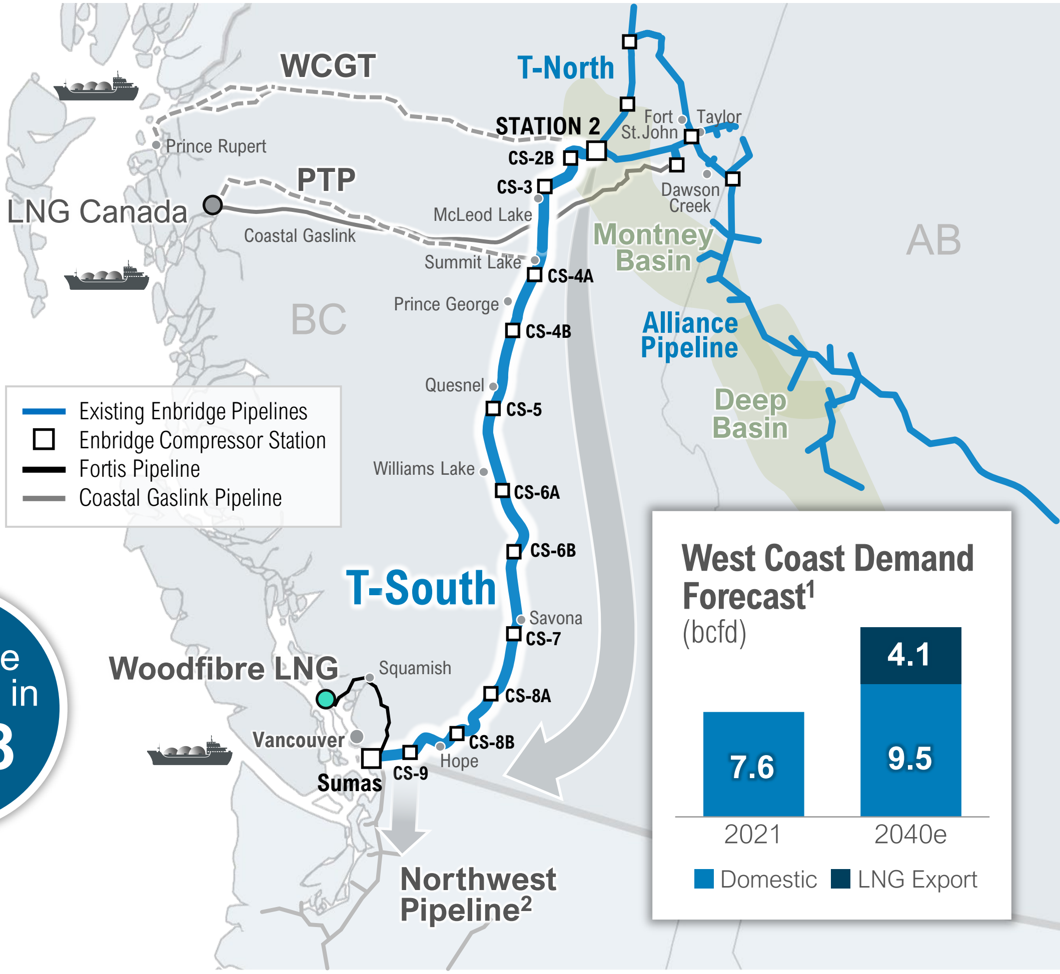
- Successful binding open season
- Expanding system by 300 MMcf/d
  - Looping & compression
- Serving regional and U.S. NW demand
- Capital cost: up to $3.6B
- Commercial model: cost of service

Next Steps:

Indigenous & stakeholder engagement → Environmental & routing assessment → CER application in 2024 → Construction mid-2026

In-service expected in **2028**

Enbridge B.C. Pipeline System



(1) Third party & company estimates (2) Northwest Pipeline owned and operated by Williams

T-North Expansions

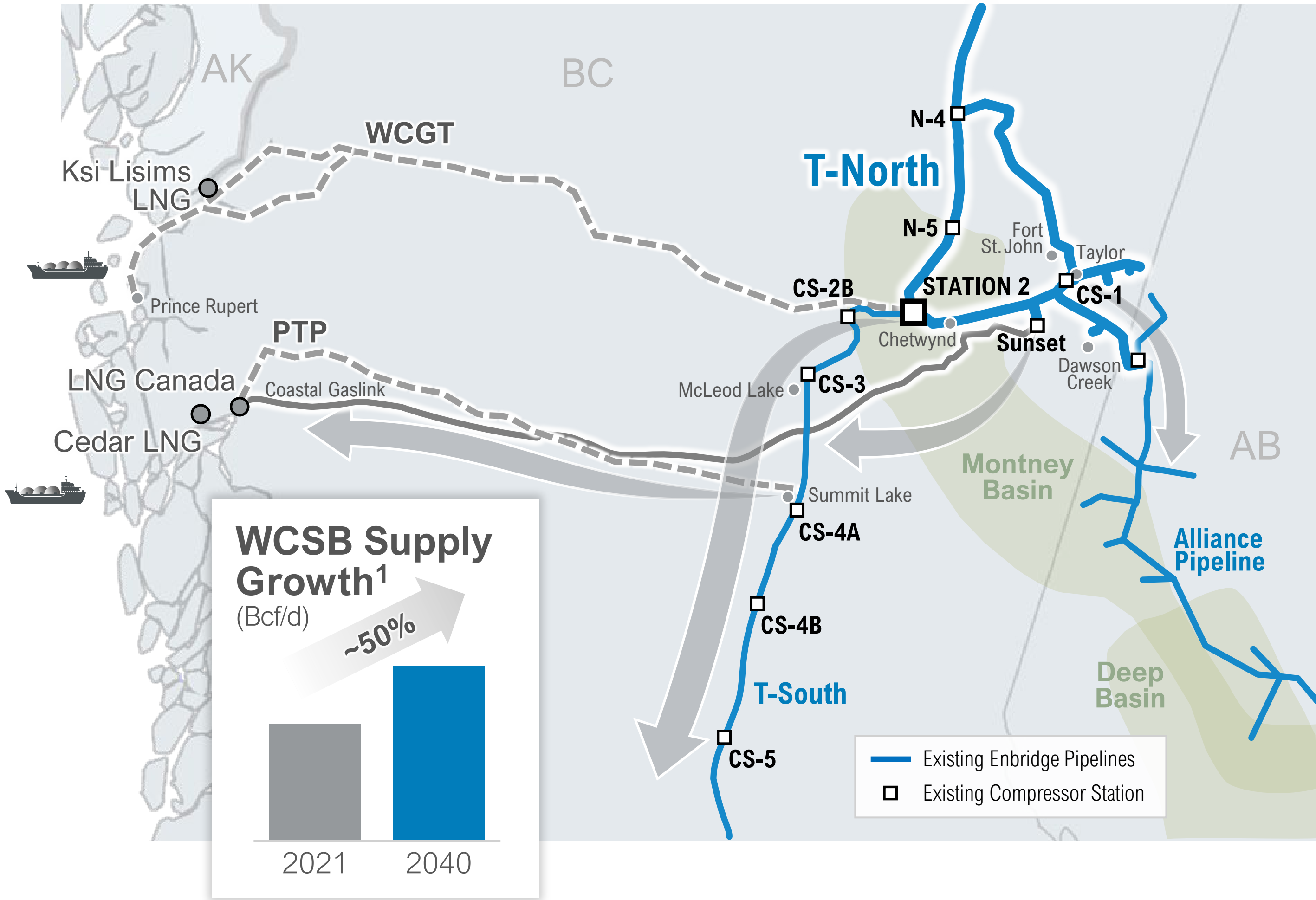
Aspen Point Program (Sanctioned Q2)

- 535 MMcf/d expansion
  - Pipeline looping and new compression
- ~$1.2B of capital under cost-of-service rates

T-North 2028 Expansion

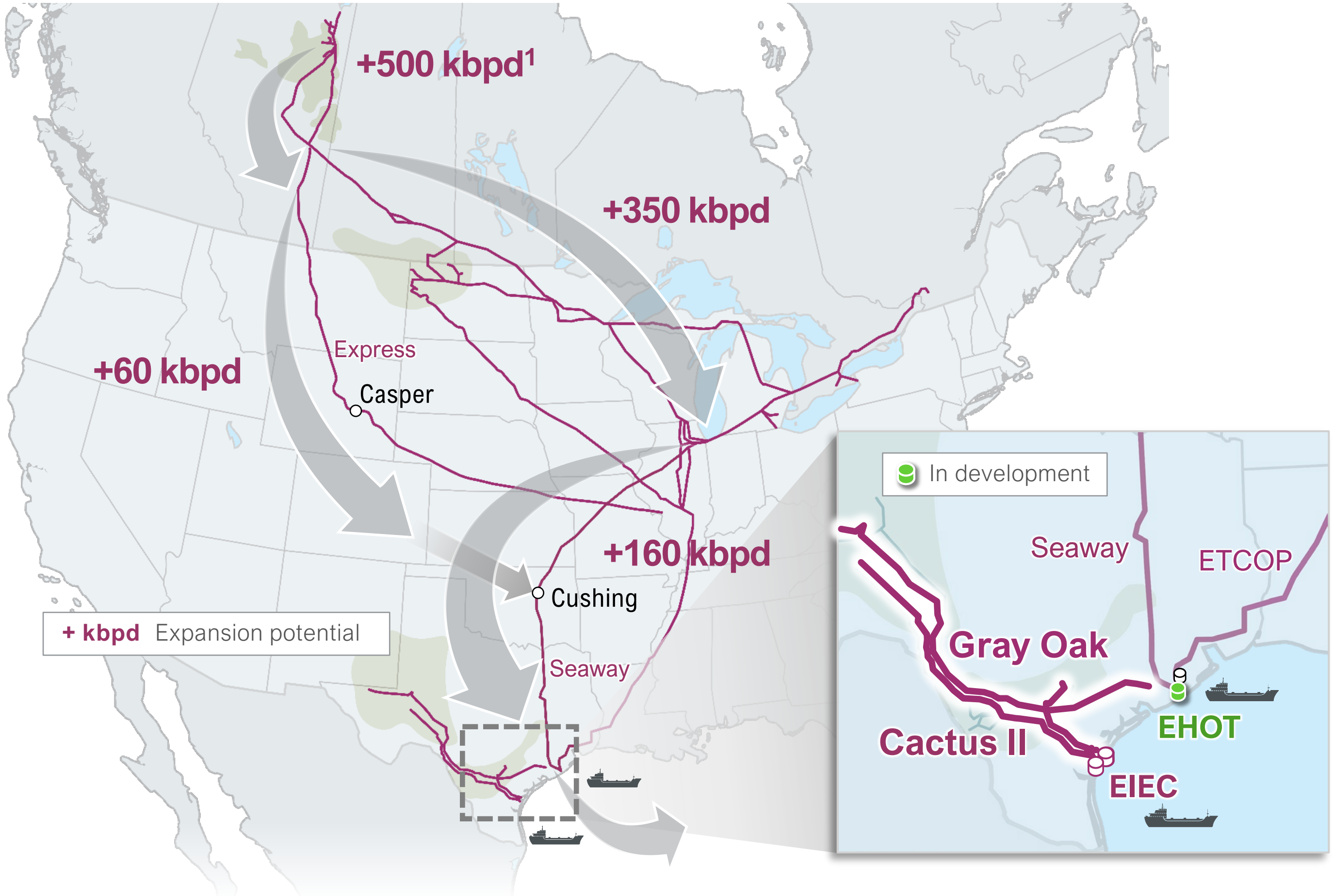
- ~500 MMcf/d capacity
  - Additional egress to accommodate Montney production growth
  - Supports West Coast LNG exports
  - Downstream demand
- Estimated capital cost up to $1.9B under cost-of-service rates
- Binding open season
  - November 4, 2022 – January 10, 2023

Enbridge B.C. Pipeline System



(1) Rystad Energy GasMarketCube, October 2022

Liquids Update



Mainline Tolling

- Two commercial options:
  - Incentive Tolling Settlement
  - Cost of Service
- Negotiations continuing
- Expansion optionality once a tolling framework is determined

USGC Strategy Build Out

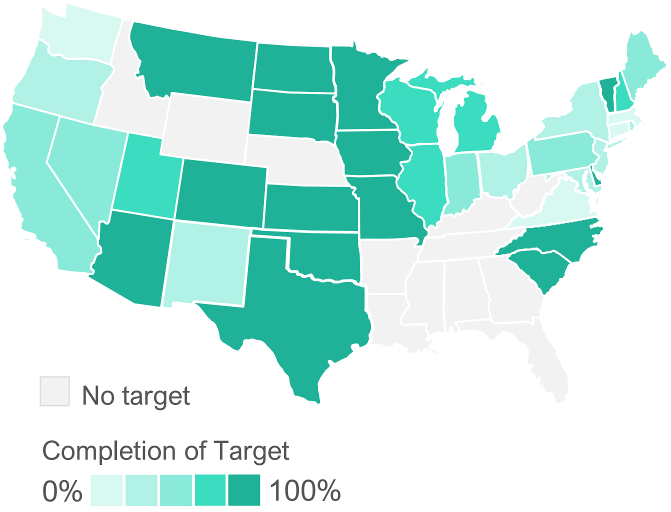
- 2 MMbbl storage expansion at EIEC **New**
  ~US$0.1B expansion; permitted
- Increased interest in Gray Oak pipeline (58.5%) **New**
- Acquired additional 10% interest in Cactus II pipeline **New**
  - ~US$0.2B purchase price

Liquids system well positioned to support growing global demand for crude oil

(1) 350 kbpd of existing regional oilsands capacity with 150 kbpd of expansion potential

Growing Renewable Opportunities in N.A.

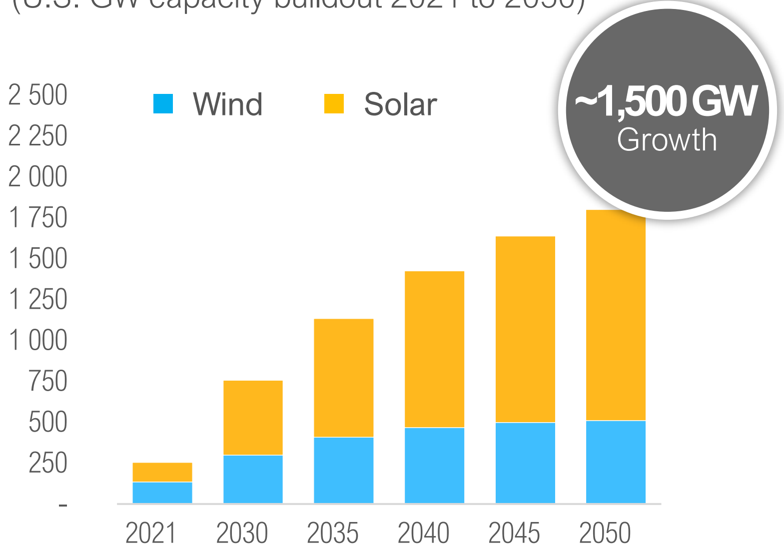
Favorable Legislation[1]



- Many states are increasing their renewable portfolio standards (RPS) targets

Renewable Capacity Growth[2]

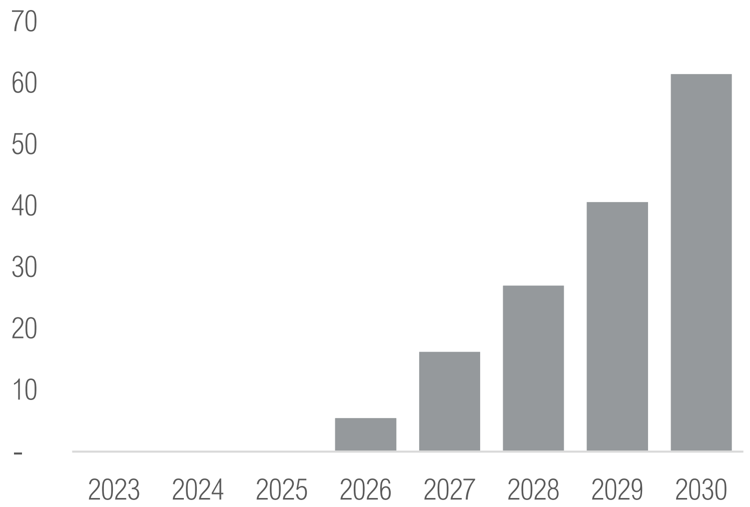
(U.S. GW capacity buildout 2021 to 2050)



- Onshore renewable capacity is expected to grow significantly in the U.S.

Cumulative Renewable Shortfall[1]

(GW)



- State renewable targets and corporate clean energy goals set to outpace build-out

Substantial renewable generation growth in North America driven by policy target and corporate ESG goals

(1) Third party & company estimates (2) IEA 2022 World Energy Outlook

Accelerating N.A. Onshore Renewables Strategy

TGE Transaction

- Completed acquisition of Tri Global Energy (TGE)
  - Purchase price: US$270MM
- 3.9 GW of projects conditionally sold to 3rd parties
  - Contracted revenue stream through 2023-2025
- ~3 GW of late-stage development projects
  - US$3B+ of capital opportunity between 2024-2028

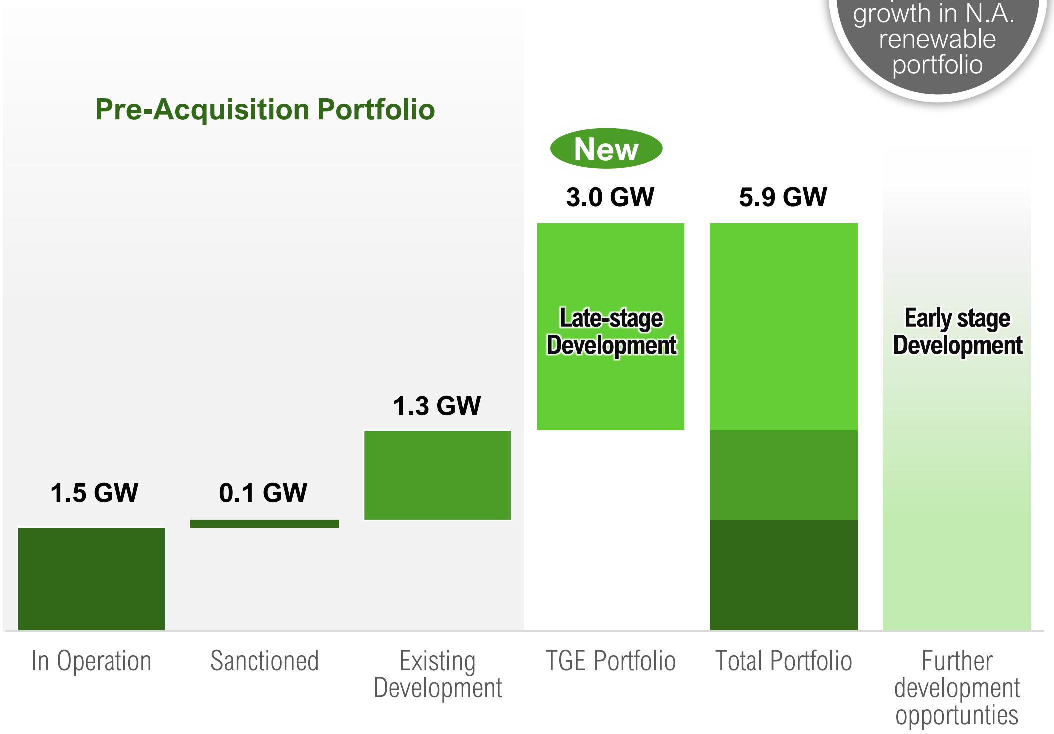
Complementary to N.A. Renewables Strategy

✓ Enhances renewable generation capabilities
✓ Supports BTM[1] and FTM[2] strategy
✓ Accretive to DCF/share
✓ Supports Enbridge growth outlook

N.A. Onshore Portfolio

(Net GW)

>3x potential growth in N.A. renewable portfolio



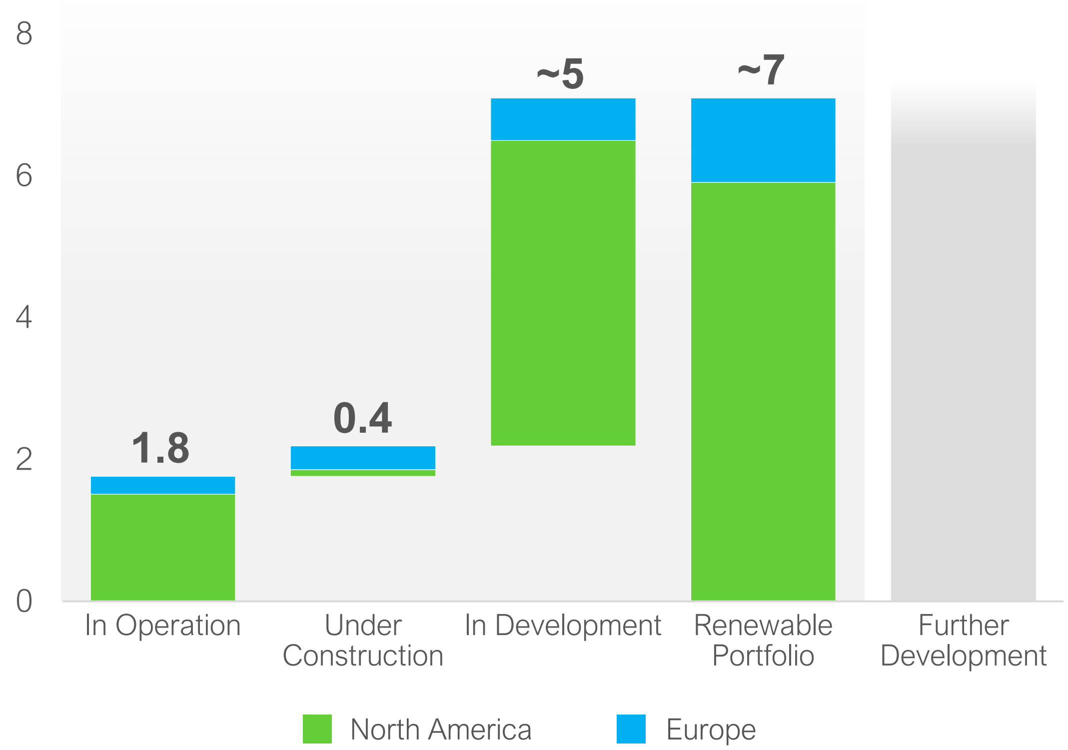
Accelerating investment in North American renewable generation

(1) Behind the Meter; (2) Front of the Meter

Growing Renewable Platform

N. American and European Renewable Asset Portfolio

(Net GW)



47 assets
in operation and under construction

Existing operations in
4 countries[1]

~11 GW[2]
gross renewable portfolio

- >$8 billion invested in renewable energy since 2002
- Full value chain capabilities
- ~7 GW development portfolio and longer-term opportunities

20+ year track record of profitably growing renewable power portfolio

(1) Soon to be five once St. Nazaire, France is placed into service later this month (2) Gross capacity: in operation: 3.6 GW, Under Construction: 1.5 GW, In Development: 6.1 GW

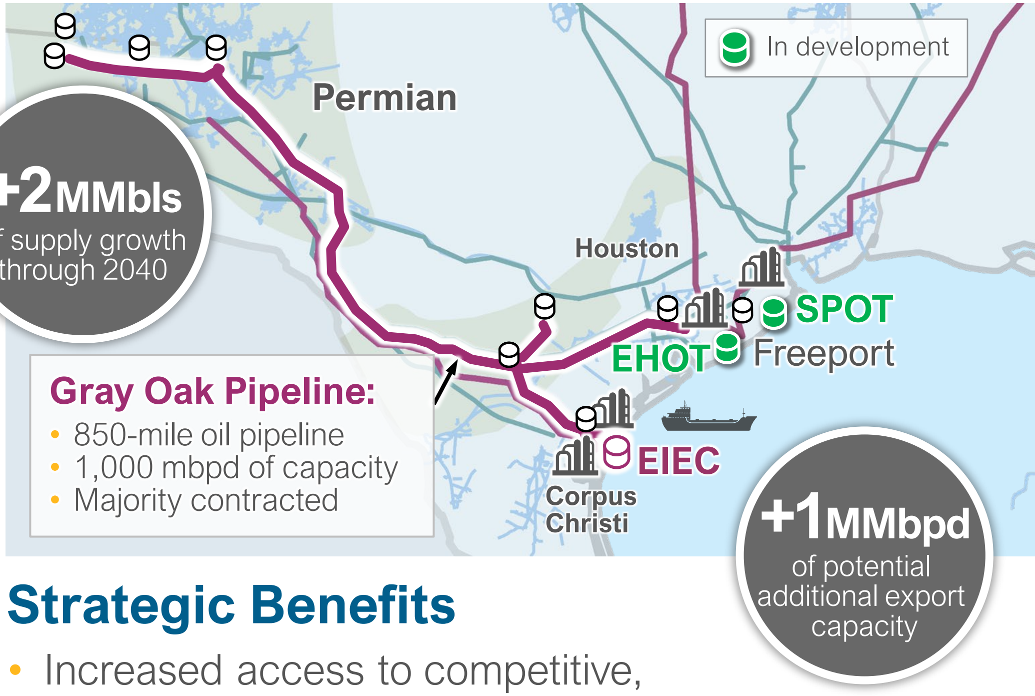
Optimizing Asset Portfolio

Enbridge/Phillips 66 Joint Venture

Closed August 17, 2022

Indirect Economic Interests[1]:	ENBRIDGE Pre	ENBRIDGE Post
DCP Midstream	28.25%	13.20%
Gray Oak Pipeline LLC	22.75%	58.50% (Operator)

Increased Interest in Gray Oak



Strategic Benefits

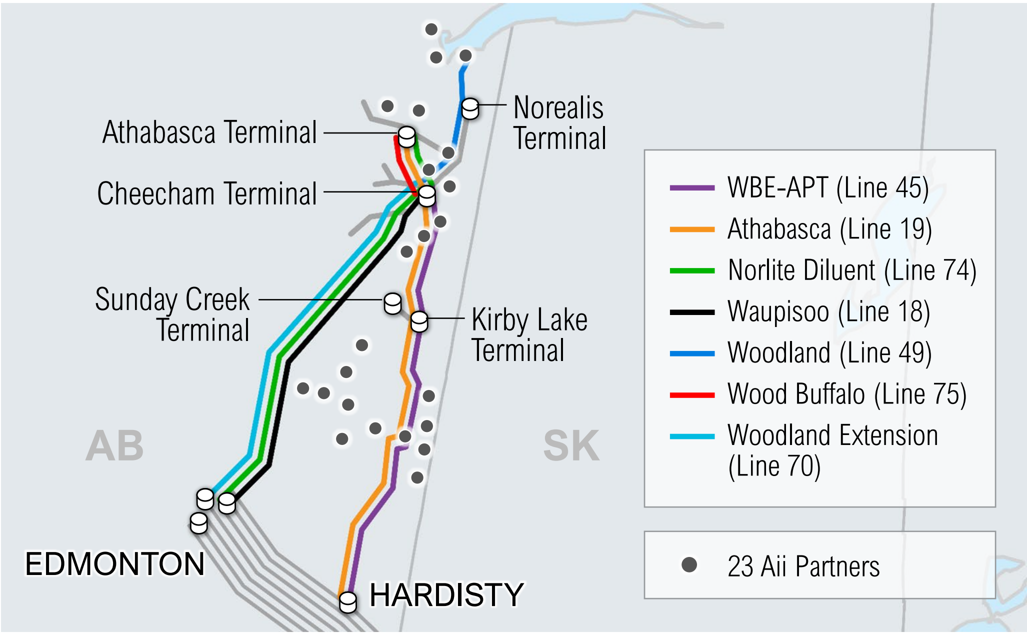
- Increased access to competitive, abundant and growing Permian supply
- Connected to existing LP assets at EIEC driving potential revenue synergies

Transaction provides operational control of Gray Oak, reduces commodity exposure and includes US$ 400 million in cash to Enbridge

(1) Pre-Transaction: ENB owned joint control in DCP Midstream LP through its 50% interest in DCP Midstream LLC

Regional Oilsands Indigenous Partnership

Regional Oil Sands Partnership



- ✓ Economic alignment with Indigenous groups
- ✓ Recycle capital at an attractive valuation

Overview

Image: Enbridge, Alberta Government, AIOC[2] and 23 Indigenous Nations

- ✓ 11.57% interest in Oil Sands trunkline assets sold to Athabasca Indigenous Investments (Aii)[1]
- ✓ Proceeds of $1.12B
- ✓ Transaction closed on October 5, 2022

Largest Indigenous energy partnership transaction in North America

(1) A newly created partnership of 23 Indigenous Nations and Governments in Northern Alberta (2) Alberta Indigenous Opportunities Corporation

Mitigating Market Risks

Risks	Mitigations
Recession	Connected to top tier demand-pull markets 98% of cash flows underpinned by COS[1] or contractual agreements Energy security concerns driving new investment opportunities
Inflation/Interest Rates	80% of EBITDA has built-in inflation protections (with some lag) Strong track record of managing multi-year capital program Active risk management program; ~90% fixed rate debt in 2022
Energy Transition	IRA[2] incentivizing low-carbon investment; improving economics Leveraging existing infrastructure to support the transition North American Energy → abundant, competitive, sustainable

Enbridge's low-risk model & dual-pronged strategy drive predictable cash flows

(1) COS – Cost-of-Service (2) Inflation Reduction Act of 2022 (US)

Q3 Financial Results

	Q3			YTD		
($ Millions, except per share amounts)	**2022**	2021	YoY	**2022**	2021	YoY
Liquids Pipelines	**2,269**	1,898		**6,581**	5,623	
Gas Transmission & Midstream	**1,158**	986		**3,300**	2,928	
Gas Distribution & Storage	**293**	296		**1,389**	1,403	
Renewable Power Generation	**113**	89		**400**	356	
Energy Services	**(132)**	(116)		**(302)**	(277)	
Eliminations and Other	**57**	116		**252**	281	
Adjusted EBITDA[1]	**3,758**	3,269	15%	**11,620**	10,314	13%
Cash distributions in excess of equity earnings	**9**	52		**153**	248	
Maintenance capital	**(215)**	(142)		**(466)**	(412)	
Financing costs	**(918)**	(757)		**(2,611)**	(2,251)	
Current income tax	**(129)**	(89)		**(391)**	(210)	
Distributions to Noncontrolling Interests	**(60)**	(66)		**(184)**	(207)	
Other	**56**	23		**199**	72	
Distributable Cash Flow[1]	**2,501**	2,290	9%	**8,320**	7,554	10%
DCF per share[1]	**1.24**	1.13	10%	**4.11**	3.73	10%
Adjusted earnings per share[1]	**0.67**	0.59	14%	**2.18**	2.06	6%

Quarterly Drivers

- ↑ Operational performance
- ↑ L3R[2] in service & Ingleside acquisition
- ↑ TETCO rate increase
- ↑ Strong European renewable contributions
- ↑ Stronger USD
- ↓ Mainline toll provision[3]
- ↓ Lower capitalized interest & higher interest rates
- ↓ Cash taxes on higher earnings
- ↓ Maintenance capex timing

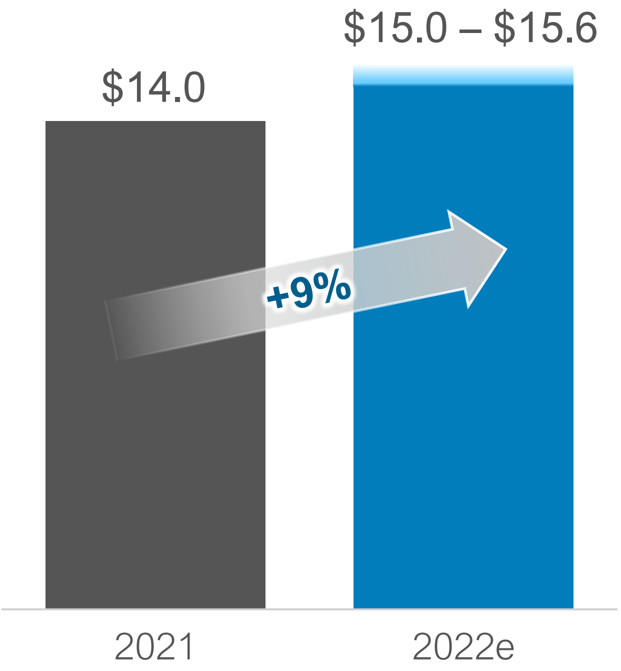
Strong operational performance year to date

(1) Adjusted earnings before interest, taxes, depreciation and amortization (adjusted EBITDA), Adjusted Earnings and Distributable Cash Flow (DCF) are non-GAAP measures. Reconciliations to the nearest GAAP measures are included in the Q3 earnings release and other documents available at www.enbridge.com; (2) Line 3 Replacement (3) Included in guidance

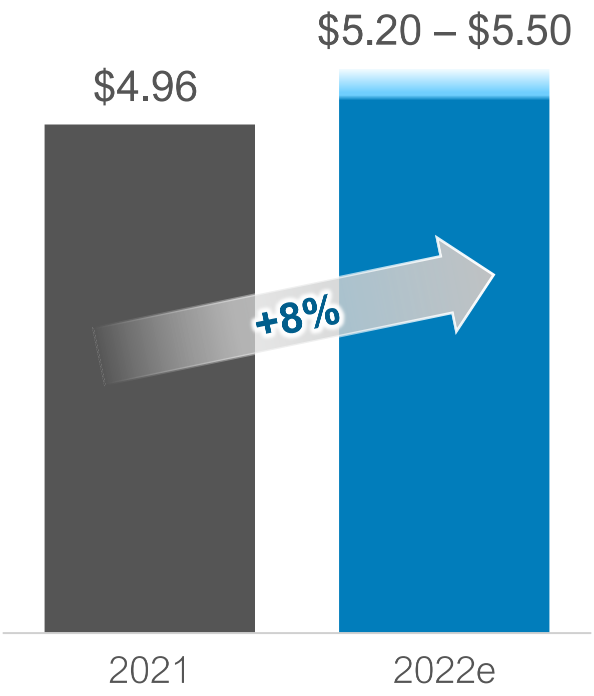
2022 Financial Outlook

EBITDA Guidance[1]

($Billions)



DCF/share Guidance[1]



Tailwinds/Headwinds to Full-Year Guidance

- \+ Strong operating performance & system utilization
- \+ Stronger USD
- – Energy Services
- – Higher power costs
- – Rising interest rates

On track to achieve full-year financial guidance

(1) Adjusted EBITDA and DCF/share are non-GAAP measures. Reconciliations to the nearest GAAP measures are included in the Q3 earnings release and other documents available at www.enbridge.com.

2023 Tailwinds & Headwinds

Strong Business Performance

- \+ Utility customer growth & escalating rates
- \+ Gas Transmission rate increases & new capital in service
- \+ Energy Services transportation contract expiries

- \+ Stronger USD

Transitory Headwinds

- – Higher power costs
- – Rising interest rates
- – Cash taxes

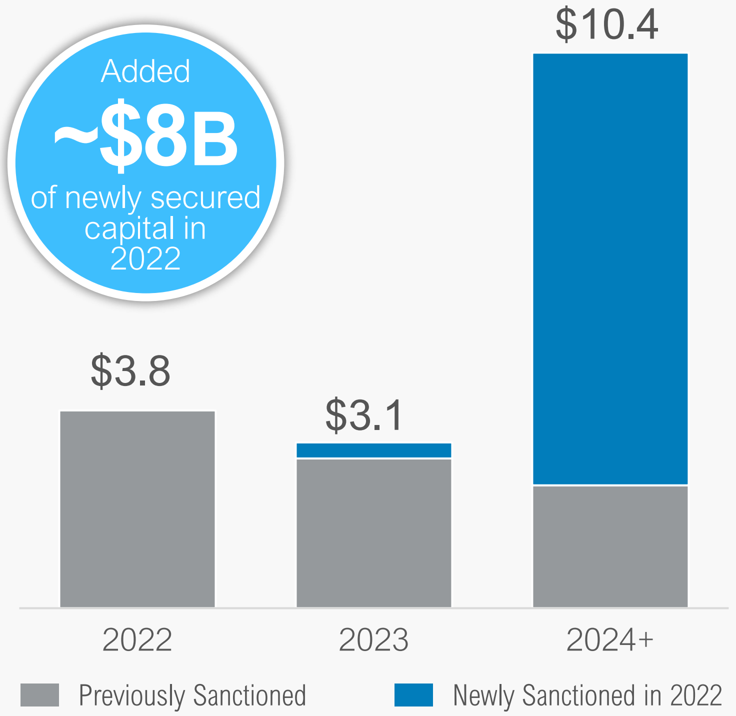
Building off a strong 2022; Navigating weakening macroeconomic environment

Secured Organic Capital Program

	Project	Expected ISD	Capital ($B)
Gas Transmission	Modernization Program	2022-2025	2.2 USD
	Other Expansions	2022-2025	0.5 USD
	Venice Extension[1]	2023-2024	0.4 USD
	T-North Expansion (Aspen Point)	2026	1.2 CAD
	Woodfibre LNG[2]	2027	1.5 USD
	T-South Expansion	2028 **New**	3.6 CAD
Gas Distribution & Storage	Distribution System	2022-2024	1.8 CAD
	Transmission/Storage Assets[3]	2022-2024	0.8 CAD
	New Connections/Expansions	2022-2024	0.8 CAD
	RNG Projects	2025-2026 **New**	0.1 CAD
Renewable Power & New Energies	East-West Tie-Line	**In Service**	0.2 CAD
	Solar Self-Powering	2023-2024	0.2 USD
	Saint-Nazaire Offshore[4]	Late 2022	0.9 CAD
	Fécamp Offshore[4]	2023	0.7 CAD
	Calvados Offshore[4]	2025	0.9 CAD
	Provence Grand Large	2023	0.1 CAD
Liquids Pipelines	Ingleside Phase VI (Storage)	2024 **New**	0.1 USD
Total Secured Capital Program			**~$17B[5,6]**
Capital Spent to Date			~$4B[7]

Secured Capital

($ Billions by in service date)



Growing secured capital program

(1) Inclusive of Gator Express Meter Project; (2) Project will be financed through a US$0.7B equity contribution and Enbridge's proportionate share of non-recourse project level debt which is US$0.6B and includes $0.2B of capitalized interest; (3) Includes Panhandle expansion; (4) Enbridge's equity contribution will be $0.2B for Saint-Nazaire, $0.1B for Fécamp and $0.15B for Calvados; (5) Rounded, USD capital translated at $1 U.S. dollar = $1.25 Canadian dollars. Euro capital translated at €1 Euro = $1.55 Canadian dollars.; (6) Secured capital program (net of project financing) $14B ; (7) As at September 30, 2022

Capital Allocation Priorities Unchanged

1 Protect Balance Sheet

$11B
Of capital recycling ($2.8B since mid 2021)

BBB+
Credit rating across all Rating Agencies

2 Sustainable Return of Capital

$7B
Dividends paid in 2022

$1.5B
Buyback program
$150M utilized

3 Further Organic Growth

~$8B
New secured growth capital in 2022

$17B
Secured Capital Program

Capital recycling surfaces value, provides capital allocation flexibility

ESG Update

Indigenous Reconciliation Journey:

2019 — **Canadian Line 3 Replacement Project:**
- ~$0.5B spend with Indigenous businesses and communities

2021 — **U.S. Line 3 Replacement Project:**
- ~$0.5B spend with Indigenous businesses and communities

2022 — **East-West Tie Line:**
- Up to 20% ownership by 6 Indigenous communities

Wabamun Carbon Hub:
- LOIs with 5 First Nations and Métis communities

Publication of the Indigenous Reconciliation Action Plan:
- September 20, 2022

Regional Oil Sands Equity Partnership:
- Agreement with 23 Indigenous Nations

Developing a strong track record of creating Indigenous economic partnership opportunities

CEO Transition

Al Monaco
President & CEO
Retiring end of 2022

Greg Ebel
Incoming
President & CEO
January 2023

2023 Financial Guidance
Late-November, 2022

Enbridge Day 2023

Toronto, ON
March 1, 2023

New York, NY
March 2, 2023

Takeaways

- ENB well-positioned for all economic cycles
- Advancing two-pronged strategy of conventional and low-carbon growth opportunities
- Executing conventional and low-carbon growth projects across the business
- Capital allocation priorities unchanged:
  - Strong balance sheet
  - Equity self-funding model
  - Disciplined allocation of free cash flow
  - Return of capital

Strategic Priorities:

Executing on all fronts

Q&A

Enbridge could spend US$1-billion expanding company turning food waste into energy

JEFFREY JONES >

PUBLISHED March 1, 2023

Source: https://www.theglobeandmail.com/business/article-enbridge-could-spend-us1-billion-expanding-company-turning-food-waste/?utm_medium=Referrer:+Social+Network+/+Media&utm_campaign=Shared+Web+Article+Links

Enbridge Inc. ENB-T is paying US$80-million for a 10-per-cent stake in a U.S. food waste recovery and renewable natural gas company, and said it could expand the business with up to US$1-billion worth of new anaerobic digester projects.

Calgary-based Enbridge said it bought into Divert Inc., a 16-year-old company that focuses on reducing waste and turning food scraps into low-carbon fuel that can be injected into any natural gas pipeline network.

The deal represents an expansion of Enbridge's strategy that has so far focused on providing biogas upgrading and renewable natural gas injection services for producers in Ontario. Its gas distribution arm set a target to increase RNG supply in the province tenfold to 5 petajoules by 2025. The company, best known for its pipeline and gas distribution businesses, calls RNG a "key pillar of its energy transition strategy."

Divert, based in West Concord, Mass., said Enbridge's equity investment is in addition to US$20-million from a fundraising round led by its current investor, Ara Partners.

The company said it plans to expand its operations in the United States to be within 160 kilometres of four-fifths of the U.S. population over the next eight years. The cash injections will accelerate its potential to offset almost 400,000 tonnes of carbon dioxide annually. The partners will also consider new wasted-food to renewable gas projects in Canada, it said.

"Divert has emerged as a leader in creatively managing wasted food and our partnership aligns with Enbridge's priorities in pioneering RNG as an effective solution to achieve net-zero greenhouse gas emissions," Caitlin Tessin, Enbridge's vice-president, strategy and market innovation, said in a statement.

It recently signed an RNG offtake agreement with oil major BP PLC worth US$175-million, which is one of the largest-ever such deals in the United States.

Enbridge earmarks $3.3-billion for U.S. Gulf Coast storage plant, other projects

Utilities across the continent are increasingly buying RNG from independent producers to meet regulations and bolster their sustainability programs. For customers, once the biogas is upgraded to RNG it is indistinguishable from the fossil fuel gas burned in furnaces and stoves. That means there is no need for new and specialized infrastructure. It can also be used as a transport fuel.

It is one way to deal with the problem of food waste, more than 100 million tonnes of which is generated each year in the United States alone, with half of that going to landfills and incinerators, Divert said.

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

October 25, 2022

OEB Staff Report to the Ontario Energy Board

Review of 2022 Annual Update to EPCOR Natural Gas Limited Partnership's Natural Gas Supply Plan

EB-2022-0141

2300 Yonge Street, 27th floor, P.O. Box 2319, Toronto, ON, M4P 1E4
2300, rue Yonge, 27e étage, C.P. 2319, Toronto (Ontario) M4P 1E4

T 416-481-1967 1-888-632-6273
F 416-440-7656 **OEB.ca**

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2.2.5 Public Policy Objectives

Renewable Natural Gas

EPCOR Aylmer stated its support of the development of an RNG market that would facilitate the inclusion of RNG in its gas supply portfolio. EPCOR Aylmer referred to the importance of Greenhouse Gas (GHG) abatement across the province, as well as the role that EPCOR Aylmer plays in supporting the achievement of GHG emission reduction targets. EPCOR Aylmer does not currently hold any RNG in its GSP. In fall 2022, EPCOR Aylmer expects to start receiving RNG into its distribution system. However, EPCOR Aylmer is not the ultimate buyer of the RNG. The RNG producer has a contract with a buyer outside of Ontario for the RNG volume, as well as the environmental attributes. As a result, EPCOR Aylmer will purchase the RNG as another source of local supply, and will not be taking ownership of the environmental attributes generated from the production of the RNG.

This arrangement allows for the development of RNG production within Ontario, as well as providing EPCOR Aylmer a learning opportunity on how to transact and procure RNG without cost impacts.

Demand Side Management (DSM)

In its filing, EPCOR stated that it would be implementing a DSM pilot in 2023 within its Aylmer or South Bruce territories.[14] In response to OEB staff's clarification questions, EPCOR confirmed that its plan changed during the course of the 2022 GSP Update and it no longer planned to implement a DSM pilot in 2023.[15] While a pilot was an early consideration for DSM portfolio introduction, further investigation by EPCOR concluded that a more reasonable approach was a staggered rollout, potentially covering a two-year DSM plan with options for residential and commercial customers.

EPCOR stated that it is planning to include a DSM proposal as part of EPCOR Aylmer's 2025 cost of service proceeding.

Community Expansion

EPCOR Aylmer stated that it has been actively working to bring natural gas to unserved communities. A number of customers have requested service and EPCOR Aylmer has

[14] EPCOR 2022 GSP Update, Aylmer, p. 23 of 91.
[15] EB-2022-0141, EPCOR Response to OEB Staff Clarifying Questions, September 14, 2022, p. 1.

Is 'renewable' natural gas a climate solution — or masterful greenwashing?

By Marc Fawcett-Atkinson | News | April 6th 2023

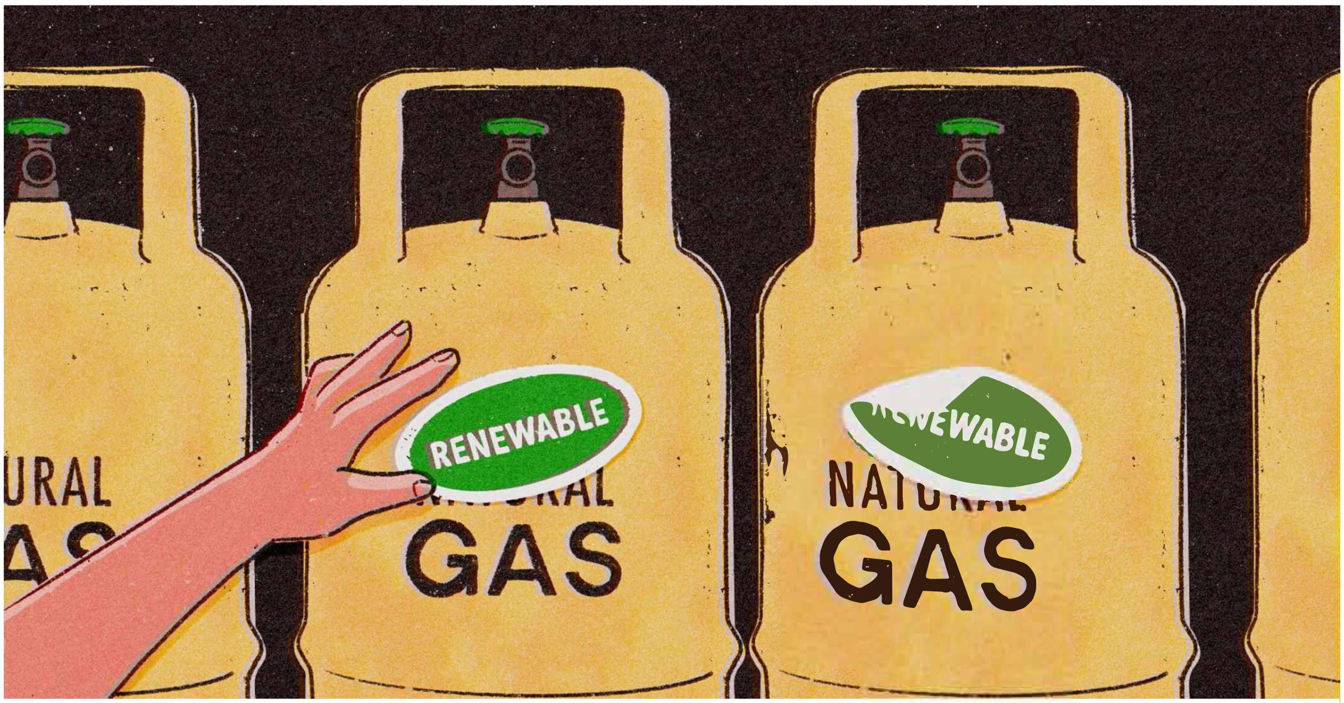


Illustration by Ata Ojani

Each time Tim Crossin turns on his gas fireplace to heat the modest home he shares with his partner, the avowed environmentalist "assuages" his climate guilt with a reminder

Unlike conventional natural gas, a fossil fuel extracted from underground deposits, this "renewable" gas is made using biomethane captured from landfills, food waste and manure pits. It is considered renewable because it is created by capturing methane — a potent greenhouse gas — emitted naturally when organic matter breaks down and transforming it into a fuel chemically identical to conventional natural gas.

"It's a way to support the biomethane industry," he explained. "I don't think we should be burning fossil fuels anymore. This gives me a moral argument to squash my guilt, basically."

But while the premium price offers Crossin climate solace, in practice, most of the gas that FortisBC Energy Inc., the provincial gas utility, supplies to his Comox, B.C., home still comes from fossil fuel deposits, not a landfill or biodigester. Crossin's gas is branded as "renewable" because he pays a premium to FortisBC, which then purchases the "renewable" designation from biomethane generated, sold and used as far afield as Ontario and the U.S.

This designation lets the company supplement the minimal amounts of B.C.-made biomethane running through its pipes with conventional natural gas that — on paper — is considered biomethane. It is a similar designation as carbon offset credits sold by airlines, which let customers offset their portion of a flight's greenhouse gas emissions by investing in emissions reduction projects elsewhere.

"They're buying not the (renewable natural gas) molecules themselves, but the environmental attributes of these molecules," explained Eoin Finn, a researcher with the environmental group My Sea to Sky. "It's fossil gas with a piece of paper attached saying: 'Hey, I'm really renewable.'"

In a statement to *Canada's National Observer,* FortisBC said it doesn't matter if the biomethane is not produced and used in B.C.

"Greenhouse gas emissions are a global issue and all climate action has a global impact. Wherever we source RNG from, it takes the place of conventional natural gas in the North American gas system, decarbonizing the gas system and decreasing net greenhouse gas emissions," FortisBC wrote.

When *Canada's National Observer* asked FortisBC whether an overall increase in natural gas use could negate the environmental benefits of using more biomethane — because the company could still use the same amount of conventional gas and top it off with biomethane — FortisBC said, "(We) purchase less conventional natural gas when we purchase RNG."

Finn sees this "paper energy" as nothing more than a ploy by FortisBC to continue supplying B.C. buildings with natural gas.

"It's total greenwashing," he said. Even the company's current renewable natural gas program, which only includes biomethane, relies heavily on gas that "never arrives (in B.C.) at all." The company's primary goal with its biomethane and renewable gas programs is not tackling climate change, he said, but "trying its best to preserve its business model" in the face of electrification.

Electricity generates fewer carbon emissions and, unlike gas, can be used both to heat and cool homes. As climate change threatens more extreme, hot weather, those dual functions are poised to make them more appealing than gas, he pointed out.

Recent years have seen municipalities across B.C. try to stop developers from putting natural gas pipes in new buildings in an effort to boost electricity use for heating. Most electricity in B.C. is generated by hydropower and generates far fewer greenhouse gas emissions than gas.

Vancouver made headlines last year when it became one of the first Canadian jurisdictions to ban the use of natural gas in new residential buildings. Quebec implemented a similar rule late in 2021 to phase out fossil fuel-based heating systems.

Outside of Vancouver, which has its own charter, provincial laws make it impossible for other B.C. municipal governments to outright ban natural gas. To get around this restriction, municipal politicians have used bylaws to ban the use of conventional natural gas in new buildings. But because renewable natural gas does not come from fossil fuel deposits, it isn't covered by the rules, Finn explained.

Last January, FortisBC fought back against these municipal rules. The company submitted a proposal to the B.C. Utilities Commission for permission to sell 100 per cent renewable natural gas to every new building in the province. FortisBC also requested permission to expand the types of gas it can call "renewable" to include other gases, like so-called "blue" and "turquoise" hydrogen, which are both made from conventional natural gas. Hydrogen can be blended with natural gas to be used in homes. The proposal is still being assessed by the commission.

The changes are necessary because "federal, provincial and municipal ... policies focused on reducing GHG emissions threaten the long-term viability of the gas delivery system," FortisBC wrote in legal filings to the commission. Mandates like the municipal bylaws banning conventional natural gas in new buildings "may cause customers to (stop)" using natural gas entirely unless the utility company can supply them with so-called "renewable" natural gas.

However, a close look at a key study led by the B.C. government and FortisBC that backs the company's proposal shows biomethane — the gas captured from landfills and biodigesters — will likely only ever account for a small fraction of the province's needs.

B.C. generates far less biomethane than is needed to meet demand. Currently, "the majority" of renewable natural gas sold in B.C. takes the form of credits generated from other companies selling biomethane outside the province, FortisBC told *Canada's National Observer* in a statement.

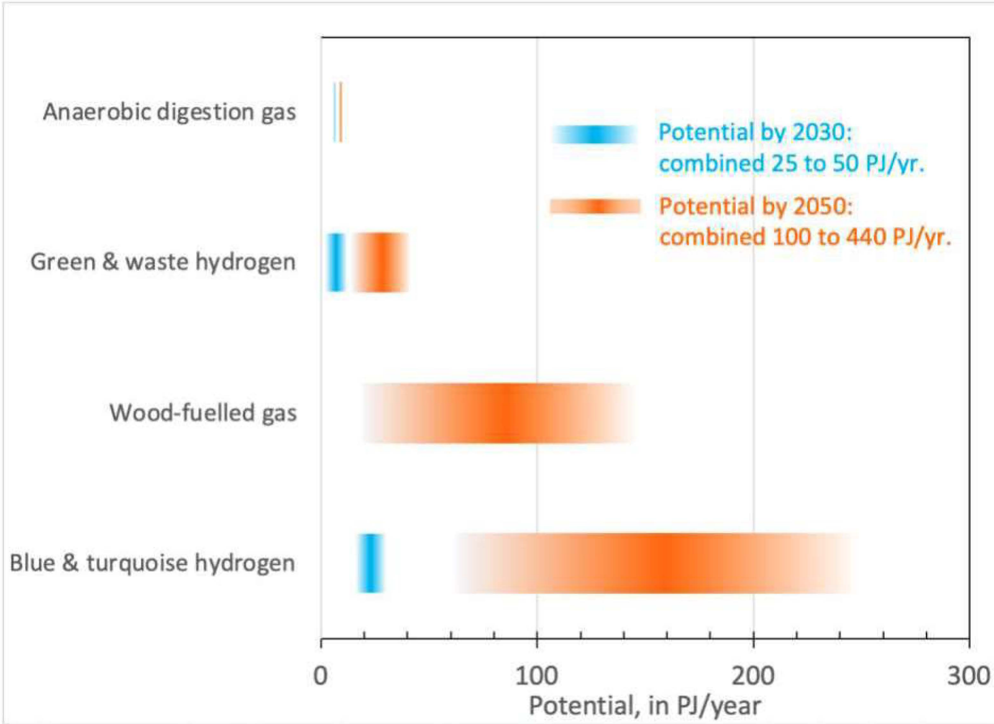


Figure 1 **Minimum and Maximum Renewable and Low-Carbon Gas Production Scenarios for B.C. for 2030 and for 2050**

Research commissioned by FortisBC and the B.C. government found that biomethane from landfills and digesters could only ever account for a fraction of B.C.'s "renewable" gas supply. Chart by Envint Consulting and Canadian Biomass Energy Research for FortisBC, the B.C. Bioenergy Network and the Province of British Columbia

According to the study, FortisBC will need to expand what counts as "renewable" and "low-carbon" to rely on gas made from wood residue — also called "synthesis gas" — and so-called "blue" and "turquoise" hydrogen to meet the province's future demand for gas. Blue and turquoise hydrogen are made from conventional natural gas but are considered low-carbon gases in the provincial government's climate laws.

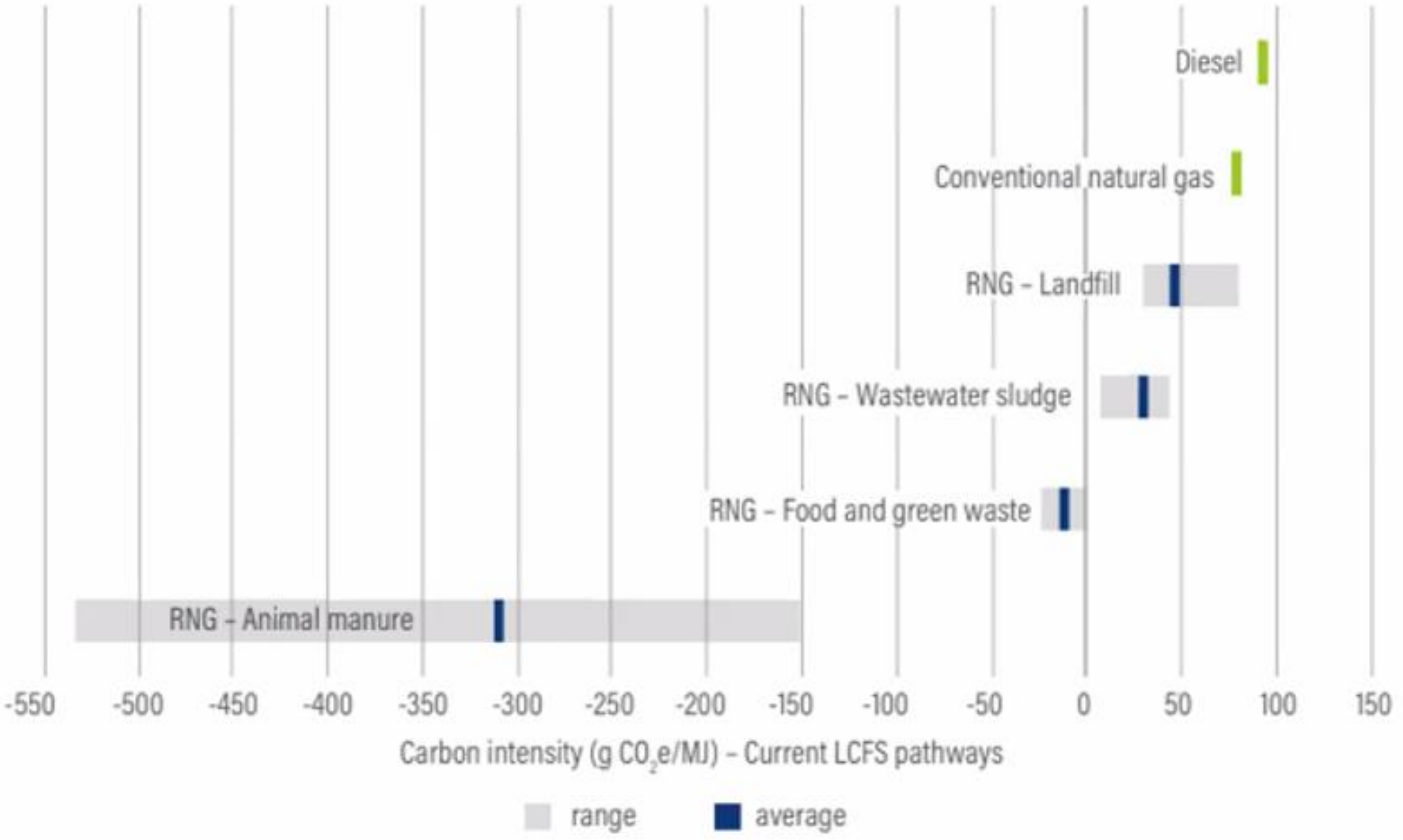
Proponents of blue and turquoise hydrogen say they have a smaller climate impact because producers can capture the greenhouse gas emissions linked to the fossil fuel at the moment of production, keeping them out of the atmosphere using carbon capture, utilization and storage technology that is still being developed. Hydrogen does not emit greenhouse gases when it burns.

In a statement, FortisBC noted: "Deep decarbonization will require ... co-ordination across gas and electric systems with a focus on affordable resiliency." Studies done in B.C. and by the International Energy Agency "acknowledge that renewable and low-carbon gases, like hydrogen, are important to a lower-carbon energy future and could be one of the most expedient ways to effective rapid decarbonization," the company said.

Critics say the technologies still rely on fossil fuel extraction and their efficacy is uncertain. It is also unclear just how much the proposal will lead to tangible changes in the source of gas molecules flowing through B.C. pipes, said Finn, the environmental researcher.

Back in Comox, Crossin, the environmentalist, echoed Finn's concern. While using FortisBC's renewable natural gas helped assuage his guilt over burning fossil fuels, it was likely a temporary measure. It won't be long, he said, before he ditches the gas fireplace and "gets a heat pump."

RNG: carbon intensity



Note: Graph from Enbridge OSEA presentation November 29, 2022

ENBRIDGE GAS INC.

Answer to Interrogatory from
Pollution Probe ("PP")

INTERROGATORY

Reference:

"The Project is expected to reduce greenhouse gas emissions by 110,000 tonnes per year" [F/1/1 Attachment 1 page viii]

Question:

a) Please provide the calculations that result in an estimated reduction from the project of greenhouse gas emissions by 110,000 tonnes per year. If the volume of RNG in the calculation differ from the RNG volumes outlined in the M13 contract, please explain.

b) Will the emission credits related the RNG from this facility accrue to Ontario natural gas ratepayers? If not, who will own the emission credits?

c) Does Enbridge intend to purchase RNG from this project to meet its Voluntary RNG program supply? If yes, what portion of the program supply is expected to come from this project?

Response

a) The M13 specifies a maximum RNG quantity at receipt point #1 of 184,104 m^3 per day. The estimate of greenhouse gas ("GHG") emission reductions in tonnes carbon dioxide equivalent (tCO^2e) is calculated as follows:

Average RNG production:
= Average daily RNG production (m^3) × 345 days of production per year
= 128,056 m^3/day × 345 days/year
= 44,179,320 m^3/year

To convert this annual RNG production value to GJ/year:
= Annual RNG production (m^3/year) × 2021 average heating value
= 44,179,320 m^3/year × 0.03884[1] GJ/m^3
= 1,715,933 GJ/year

Where the RNG is used to displace gasoline in vehicles, with an energy content of 34.66 GJ per cubic meter of gasoline, [2] the equivalent litres (L) of gasoline is:
= Annual production of RNG (GJ/year) ÷ energy content of gasoline (GJ/m^3)
= 1,715,933 GJ/year ÷ 34.66 GJ/m^3 of gasoline
= 49,508 m^3 of gasoline × 1000 L/m^3 of gasoline
= 49,507,588 litres of gasoline

And where the emission factor is 0.00232 tonnes carbon dioxide equivalent per liter of gasoline,[3] the avoided GHG emissions equal:
= Annual production value (L) × emission factor of gasoline (tCO^2e/L)
= 49,507,588 L × 0.00232 tCO^2e/L
= 114,857 tCO^2e

The annual emissions reduction from RNG produced in the Project displacing gasoline use in vehicles is 114,857 tonnes carbon dioxide equivalent per year, or 110,000 tonnes carbon dioxide equivalent per year when rounded to two significant figures.

b) Please see the response at Exhibit I.STAFF.1, Part b). Although this supply is being produced in Ontario, because Enbridge Gas is not procuring the RNG supply being produced at this facility, the emissions credits will accrue to the party or jurisdiction that ultimately procures the supply from Waste Connections.[4]

c) Please see the response at Exhibit I.STAFF.1, part b).

[1] https://www.enbridgegas.com/-/media/Extranet-Pages/About-Enbridge-Gas/learn-about-natural-gas/gas-composition-and-high-heating-value-data.ashx?rev=2d56f5ca107e4b0ba1d031935fb584d9&hash=7FEBBAD0E9AEAF372EFA423F023CDFBA
[2] https://apps.cer-rec.gc.ca/Conversion/conversion-tables.aspx?GoCTemplateCulture=en-CA - 2-5
[3] Table A6 1-14, 2021 National Inventory Report: https://publications.gc.ca/collections/collection_2021/eccc/En81-4-2019-2-eng.pdf
[4] The Ridge Landfill site is owned by Ridge Holdings, L.P., a wholly owned subsidiary of Waste Connections.

PROPOSED RIDGE LANDFILL RNG PROJECT

NOTICE OF STUDY COMMENCEMENT AND VIRTUAL INFORMATION SESSION
CHATHAM-KENT, ONTARIO
ENBRIDGE GAS INC.

The Study

Enbridge Gas Inc. (Enbridge Gas) has retained Dillon Consulting Limited to begin an environmental study for the proposed Ridge Landfill Renewable Natural Gas (RNG) Project located in the Municipality of Chatham-Kent, Ontario.

Landfill gas generated by decomposing waste will be captured and transformed into RNG that will be processed for injection into the local natural gas distribution system. The project is expected to reduce greenhouse gas emissions by 110,000 tonnes per year. This is enough to heat more than 18,000 Ontario homes every year or about 40% of the homes in Chatham-Kent.

The project will involve the construction of a new RNG injection station at the Ridge Landfill and a 4-inch extra high pressure steel pipeline. Enbridge Gas has identified a preliminary preferred route that runs 5.7 km between Enbridge's Chatham East Line at Blenheim North Station to the Ridge Landfill, and two alternative routes (see map).

Once the study is complete, Enbridge Gas will apply to the Ontario Energy Board (OEB) for approval to construct the project. If approved, construction may begin in spring 2023.

The Process

The study is being conducted in accordance with the OEB's *Environmental Guidelines for the Location, Construction, and Operation of Hydrocarbon Pipelines and Facilities in Ontario*. The study will review the need and justification for the project, describe the natural and socio-economic environment, evaluate the project from a social and environmental perspective, outline safety measures, and describe appropriate measures for impact mitigation and monitoring.

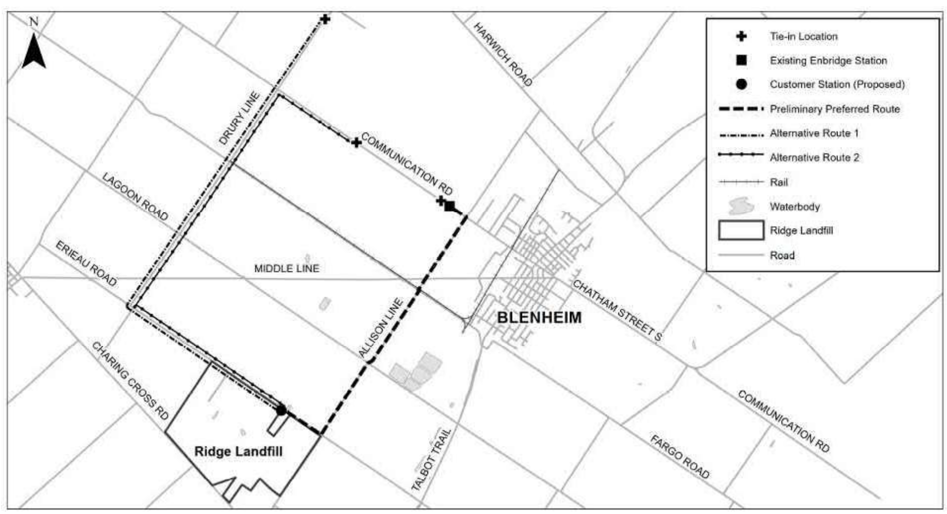
Invitation to the Community

Stakeholder and Indigenous consultation is a key component of this study. Members of the general public, landowners, government agencies, current customers, Indigenous communities, and other interested parties are invited to participate in the study. We are hosting a Virtual Information Session to provide you with an opportunity to review the project and provide input.

Virtual Information Session Website: www.RidgeRNG.ca
Active Dates: Monday, April 25 to Sunday, May 8, 2022

Your input will be used to confirm the preferred route and create mitigation plans to be implemented during construction. If you are interested in participating, or would like to provide comments, please visit the Virtual Information Session website or contact one of the individuals listed here. The last day to submit comments for consideration in the environmental study is **May 24, 2022.**

Enbridge Gas Project Website: www.enbridgegas.com/RidgeRNG



Tanya Turk
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Suite 101 - 177 Colonnade Rd. South, Ottawa, ON K2E 7J4

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613-745-2213 ext. 3024

ENBRIDGE GAS INC.

Answer to Undertaking from
Pollution Probe (PP)

Undertaking

Tr: 20

To confirm that the RNG strategy doesn't exist, and if it turns out it does, provide a copy

Response:

As provided in response at Exhibit I.2.6-PP-38, Enbridge Gas confirms that Enbridge Gas has a Renewable Natural Gas (RNG) Station Strategy, as defined in the Asset Management Plan (AMP).

As provided at Exhibit 4, Tab 2, Schedule 7, Enbridge Gas has proposed a Low-Carbon Voluntary Program (LCVP), which is a program for the procurement of low-carbon energy for large volume sales service customers. LCVP will include the procurement of RNG. The LCVP will be addressed in Phase 2 of this proceeding.

Enbridge Gas confirms that there is no other overarching RNG strategy document.

bottom.

MR. BROPHY: There's a --

MR. RINGO: Page numbered number 3. Yes. 1, 2, 3 at the bottom of the -- there we go.

MR. BROPHY: Okay. Yeah, that's the one there.

So it's kind of at the bottom. That's what I wanted to talk about.

If you can't read it, just let them know, and you can zoom in because it is the bottom graph there with the breakout that I wanted to talk about.

Okay. When I look at that graph at the bottom it looks like the only natural gas that's being used in 2050 is for large industrial customers that would have natural gas and CCOS. Is that accurate?

MR. RINGO: Yes.

MR. BROPHY: Okay.

MR. RINGO: Well, in renewable natural gas. You see the dark green sliver as well?

MR. BROPHY: Oh, okay. Yeah. I consider RNG something different than natural -- I should say fossil gas, but used to calling it natural gas.

Okay. And so I think CCOS would require a large investment by those customers.

Well, it would require a few things, and I just want to kind of go through the list to make sure you agree.

One is it would, you know, be a large investment. They have to put in, you know, the equipment to capture and clean, et cetera.

They'd have to have proximity to geological storage, and that type of facility itself would have to have to include a CO2-rich facility stack so that emissions can be captured efficiently; does that all sound correct?

MR. RINGO: Yes.

MR. BROPHY: Okay. Do you know how many Enbridge customers you've assumed in your modelling would meet those kind of criteria and be able to use natural gas with CCOS?

MR. RINGO: Can I take a breakout with the Enbridge Gas panel to discuss this prior to answering, please.

MR. BROPHY: Sure.

[Witness panels confers]

MR. RINGO: Mr. Brophy, thanks for the question.

So Guidehouse did not do the customer count for customers eligible for CCS conversion or attachment. We inherited that natural gas plus CCA projection from the ETSA study, which I believe tracked it up through 2038, and then we extrapolated that out to the end of our study period, 2050, so I think that's a question I can't answer, but the data may exist.

MR. BROPHY: Yeah, no, fair enough, and thankfully I think we have Posterity on this panel, so I guess it's the same question for Posterity if that's where the estimate of customers and load for CC -- or natural gas -- fossil fuel -- fossil gas plus CCUS came from. Maybe they can answer it.

MR. SHIPLEY: So I don't think we can answer it right off the top of our head, but we would have been -- or we would have discussed with Enbridge which specific end uses and customer segments within industrial were suitable for this, for CCUS and distributed the CCUS among that customer group.

Now, if we didn't completely saturate those end uses and those segments, then we wouldn't necessarily be able to say how many customers it actually is.

We could probably make an estimate of what percentage of those end uses and customer segments would have -- what percentage of that amount of metre-cubed would have been cubed into CCUS by 2038.

MR. BROPHY: Okay, so if I heard correctly, the Guidehouse modelling for this came from Posterity and Posterity got a list from Enbridge on the customers it believes would fit into this category; is that correct?

MR. SHIPLEY: No, it's not a list of customers. It is a set of end uses and customer segments, and we know how many customers altogether are in those customer segments, but we don't have a list.

MR. BROPHY: Okay, would you be able to provide the information that you do have? So you have customer segments, and what was the second part, sorry?

MR. SHIPLEY: The energy end uses.

MR. BROPHY: The energy end uses; okay. So maybe those --

MR. SHIPLEY: Yeah.

MR. BROPHY: -- things.

MR. SHIPLEY: Yeah. So we can give you a list of end

ENBRIDGE GAS INC.

Answer to Undertaking from
Pollution Probe (PP)

Undertaking

Tr: 153

For Guidehouse to indicate how their model deals with the energy and related emissions from the parasitic losses due to CCS or to confirm if it doesn't.

Response:

The following response was provided by Guidehouse Canada Ltd.:

The CCS emission results from the Guidehouse model include the combustion emissions based on a 95% capture rate, as well as upstream emissions from methane transmission. It does not include emissions or energy use from parasitic losses (losses associated with incremental energy consumption of the CCS process).

ENBRIDGE GAS INC.

Answer to Undertaking from
Environmental Defence (ED)

Undertaking

Tr: 63

To confirm whether your sources for the cost of blue hydrogen assumed that the energy to drive the SMR process and the energy required to power the carbon capture were 100 percent zero emissions electricity.

Response:

The following response was provided by Guidehouse Canada Ltd.:

Guidehouse confirms that the sources used for estimating blue hydrogen costs (please see attachments to Exhibit JT9.11) describe the use of electricity as a potential option for producing high-temperature steam for SMR processes; however, these sources do not explicitly consider the cost of 100-percent zero-emissions electric SMR processes or electric carbon capture facilities in the blue hydrogen cost estimates.

MR. RINGO: I don't think we need to pull those up now, but the line items should be fairly obvious if you search for CCS in that workbook.

MR. BROPHY: Okay, great. Thank you. Thank you for that.

Okay. So my next question is in relation to hydrogen, which we talked a little bit about before, and Guidehouse indicated that you included hydrogen storage via geological storage, and I'm assuming that assumption is still the same, nothing changed there; is that correct?

MR. RINGO: There was one change in our hydrogen storage calculation approach, and if you switch back to April 5th letter on that table -- I don't know if you want to count your way down, but the 14th row of that table -- no, I'm sorry. Which row was it? 17th row -- a model enhancement.

Yup. Updated hydrogen storage to better reflect the seasonality of hydrogen storage.

What the model was doing before was all of the hydrogen produced in one year, it could be stored from season to season but could not be stored from year to year, and so it would clear out all of the hydrogen storage at the end of the year, and we had enhanced the model so that hydrogen storage could carry over from one year to the next, just to be more -- better reflect reality, right? That's not like you have to spend it all by December 31st.

So that was the only change.

I don't think it had a material change on the results, but, you know, you asked what changes we made. That's it.

MR. BROPHY: Okay. Great. Thank you. And the geological storage for hydrogen, you used that because that's the most economic way to store large volumes? Is that why you picked that?

MR. RINGO: Right.

MR. BROPHY: Okay. So one of the items -- and I think you were here when Enbridge -- I think it was their director of engineering was talking a bit about this in the technical conference previously, and they had indicated that, you know, Enbridge wouldn't be using geological storage and then releasing hydrogen into its transmission and distribution system that way, and I won't get into all the reasons, but part of it is because, you know, they don't know which pipelines can handle hydrogen or not, so they do it on a very isolated systematic basis like what they're doing with the Markham pilot that they're doing.

And that they'd actually be having to include hydrogen by zone and by subsection rather than using it the way you've modelled.

So I guess the challenge is if we do what Enbridge says they're going to have to do from an engineering point of view rather than store it geologically and then, you know, release it into the system, is there any way for you to model that, or you just -- that is too big a change to your modelling and report and cost models.

MR. RINGO: In other studies, larger, more complex, multi-year studies, we have in the past done a regional approach where some regions have storage and some don't, and you model the transfer between regions to put it in and out of storage or not.

This was not that level of detail.

This was -- you know, we had one region, Ontario, and its connection to its neighbours, and so if it's stored in Ontario, it's stored there, we don't model the shifting around or the alternative, you know, options that would be required -- we don't get down to the pipes and tubes, you know -- I'm sorry, that's not the way to phrase it.

It's just not done at that level of granularity. This is meant to be a high-level study where we're looking at, you know, hydrogen is produced. It has -- you know, we want to save some for later, we have to store it, there is a cost associated with that, trying to capture all the different moving pieces, but without going all the way, you know, ten levels down on any single one of those, because then you set yourself up with a study you can never finish.

So to your question, can we do that, it's possible. Can we do that with this study? No, that's not how this was framed.

MR. BROPHY: Okay. I'm going to end there. Thank you very much. I appreciate all the answers.

MR. RINGO: Thank you, Mr. Brophy.

MR. MILLAR: Thank you, Mr. Brophy.

Next on our list we have the School Energy Coalition, which I assume is Mr. Rubenstein, and there he is.

EXAMINATION BY MR. RUBENSTEIN:

MR. RUBENSTEIN: Good morning, panel -- or good afternoon.

I just have a couple questions left. And one of the issues that the updated study reveals is that one of the big driving points remaining between the two scenarios is the price of carbon.

And so if ultimately that there's a -- if you remove the price of carbon, or there is a difference in the price of carbon, it could have a substantial difference in the outcome, and I want to just understand just some of the assumptions in how you essentially made some of the calculations.

And as I understand -- and this is in Appendix A of your report, table A2 in either report -- you have assumed different carbon prices for the diversified and electrification scenario, and I understand, because the principle behind the different prices for each of those scenarios is the idea that to meet the electrification goals the government will undertake a different set of policy choices, which would include a higher price of carbon; do I have that correct?

MR. RINGO: This may be a question for the Enbridge Gas panel, or should we confer, Enbridge, on this question?

MS. MURPHY: No, I can take that.

This is Jennifer Murphy from Enbridge Gas. So, yes, that's correct. We envisioned these two scenarios and started that work with Posterity and then a transition scenario analysis, and when we looked at the carbon price we felt that that would be a lever that the federal government would just pull harder on to get that level of electrification that was needed, so that's where the assumption stems from, was from the earlier work, and because that value does have an impact on demand, that -- that level of carbon price was continued into the Pathways study, because it's baked into the demand that came out of the ETSA work that was used as the foundation for the Pathways work.

MR. RUBENSTEIN: And did you assume any other -- let's call it policy or regulatory differences that would affect prices of any of the inputs? That differ between the two scenarios, let me clarify.

MS. MURPHY: I think I'll start that and then invite Guidehouse to jump in.

I think there were some that were -- where there was different prices of things that were between the scenarios, and then if we were to look at the list of what has changed in this most recent report, some of them were reverted to the common. Those were ones where it was possible to do so because it didn't -- you know, that was independent of the earlier ETSA work.

This one's a bit more tricky to make the change, because it was done [audio dropout]. So, I mean, I still think that it's accurate to think that in electrification scenario this is a lever the government could pull, but if we wanted to change this only in the Pathways study it would be a bit difficult to do that.

MR. RUBENSTEIN: Don't worry. I'm not going to ask you to re-run the model. I'm just trying to understand that.

But my question is: Are you -- and I understand the history here.

Did you assume any explicit regulatory changes, so this is a policy change that -- policy regulatory change that affects the carbon price, but others that has implicit -- let's call them implicit price effects on the other inputs to the models.

MR. RINGO: I think Jennifer gave an answer, and I'll follow up there. No, I can't recall any explicit policy or regulatory -- other influences that differed between scenarios.

MR. RUBENSTEIN: So when I go look and I'm now reading how you determine the carbon price forecast, and I think there is a reference in some other documentation in the evidence, but, as I understand, for the diversified, you essentially took the 2030 price that the government has already announced, then you -- either it was Enbridge based on some previous work, or Posterity, I don't know -- inflated that to a 2038 price. Do I have that correct? And then Guidehouse or Enbridge, I'm not clear, used a 2 percent inflation after 2038. Do I have that correct?

MS. MURPHY: I think so. I'll just play back the part that happened in the earlier Posterity work and then Decker can comment on that and what they did for the Pathways study, but we took the -- Posterity took the announced carbon price to 2030 and then applied inflation for the remaining years; 2 percent sounds about right. And then, Decker, do you want to comment? Then what did you do after that? I believe you continued the inflation.

MR. RINGO: That's right.

MR. RUBENSTEIN: Yes, but this is where I get a little confused. I'm not aware of the 2038 price. Right? There is a 2030 price.

MS. MURPHY: That's right.

MR. RUBENSTEIN: And then, as I understand, there was some inflated -- either Enbridge or Posterity inflated it to 2038. Correct?

MS. MURPHY: Just at an annual rate of inflation.

MR. RUBENSTEIN: And so my question to you is: What was that rate, since it's not 2 percent? Some number that I believe would be higher if you just run the numbers. Is that something you can undertake to tell us?

MS. MURPHY: Please just give us one moment. This late in the day, we don't necessarily want to take an undertaking if we can find the answer so, if you can give us a minute, we'll try to find it.

MR. RUBENSTEIN: That's fair. And I will ask you another question that you are almost certainly going to need to take an undertaking, too, that is sort of related, so maybe....

MR. STEVENS: Sure, go ahead.

MR. RUBENSTEIN: So then my second question is about the electrification carbon price. And, as I understand, you looked at PBO estimates for a study they did to determine what we would need -- what the carbon price would need to reach the Paris 2030 targets. Do I understand that at a high level? That was step one.

MR. STEVENS: When you are say "you," Mark, are you speaking of Guidehouse?

MR. RUBENSTEIN: No. I understand -- well, I believe this was either Enbridge or Posterity. Do I have that correct?

MS. MURPHY: Yes. That was done in the earlier work, working with Posterity.

MR. RUBENSTEIN: I'm told Guidehouse is in the break-out room. I'm not sure.

MR. STEVENS: They're back.

MS. MURPHY: Yes, we're here.

So, yes, that carbon price in the electrification scenario was based on the work that was done with Posterity and the ETSA work.

MR. RUBENSTEIN: But I understand, and it says so right here in -- it says at some places in other parts of the evidence, but it says:

> "For the electrification scenario, the Parliamentary Budget Officer's estimates required to meet Canada's 2030 climate targets are used."

That was step one. Do you see that?

MS. MURPHY: Yes.

MR. RUBENSTEIN: And there is a footnote to that. I cannot draw the line between the 2030 numbers you are using in the electrification and the numbers in that study, and so I was wondering if, by undertaking, you could draw that line for me.

MS. MURPHY: Okay. I think we can take that. And we can just confirm it -- if you don't mind if we do it on the same one, we can confirm the rate that it was inflated for the diversified.

MR. RUBENSTEIN: Yes.

MS. MURPHY: So I just want to clarify that I understand the undertaking. So the first part is we would clarify the inflation rate used from 2030 to 2038, and then the second part is to clarify how we arrived at -- is it the 2030 number that you are saying doesn't align?

MR. RUBENSTEIN: Well, part one is, as I understand, the intent of that report is to get you to some sort of 2030 number. That would be part one. And then the second part is: What is the inflation that gets you to 2038? I'm presuming it's the same as for the diversified scenario, but you can tell me in the undertaking if I'm wrong about that.

MS. MURPHY: Okay. Yes, I think that makes sense. I believe the same inflation rate would have been used in both cases, but there is a lot of paper in that report and I'm just not finding it in the ETSA study, so we can confirm that and then also clarify the number for 2030 in the PPO report.

MR. RUBENSTEIN: Now, I call these carbon input prices. And I use the term "input" because they are the

inputs to the model. And, if we go to ED-60 --
MR. MILLAR: Mr. Rubenstein, I just wish to mark that undertaking before by carry on.
MR. RUBENSTEIN: Oh, sorry. I apologize.
MR. MILLAR: So it was, as described by you, JT9.24.
UNDERTAKING NO. JT9.24: (A) TO CLARIFY THE INFLATION RATE USED FROM 2040 TO 2039; (B) TO CLARIFY THE INFLATION RATE USED TO GET TO THE 2038 NUMBER; TO CONFIRM THE CALCULATION OF THE 2030 NUMBER
MR. RUBENSTEIN: If we can scroll down to the table in part (c), there you're showing carbon cost per tonne, and I call that the carbon prices that are the output of the model. Is that a fair characterization?
MR. RINGO: No, those are also the input, just expressed in real 2020 dollars.
MR. RUBENSTEIN: Okay. So that's the only difference, is that they are expressed in real 2020 dollars?
MR. RINGO: Instead of nominal dollars, right.
MR. RUBENSTEIN: So the 2050 at $138.78 in the carbon cost per tonne in 2020 real dollars equals $251 in the nominal dollars that were shown in Appendix A?
MR. RINGO: That's right. And it also equals the 2040 cost of $138.78, because all that is done between 2040 and 2050 is applying inflation; which, if you are looking at real 2020 dollars, doesn't change it.
MR. RUBENSTEIN: Okay. I just wanted to clarify that. Now, if we can go to 1.10 SEC 67. I just want to clarify something. As I understand....

MS. ROSZELL: We're trying to move to a different -- pulling something up on the screen. Right?

MR. RUBENSTEIN: Yes.

MS. ROSZELL: Perfect.

MR. RUBENSTEIN: So if we go to the attachment, as I understand this memo, this was a memo that Guidehouse -- essentially, Guidehouse completed a table for Posterity. Do I have that correct? It is both oddly worded in the underlying evidence and it is oddly worded in the memo.

MS. ROSZELL: It is by Posterity to Guidehouse, so it is submitted to us. It is inputs that are from the Posterity study for the Guidehouse study.

MR. RUBENSTEIN: But, as you read it, it talks about how this template has been provided to Guidehouse from Posterity.

MS. ROSZELL: Right.

MR. RUBENSTEIN: And then it is filled out, so presumably --

MR. WOOD: Sorry, it is Cody Wood from Enbridge. Could we have a moment to confer with Guidehouse for a second? I just want to make sure we have a common understanding of what this memo is.

MR. RUBENSTEIN: That's fine. It would be helpful.

MR. WOOD: Thank you.

[Witness panel confers]

MS. ROSZELL: So, Mark, to clarify, this table is provided by Posterity to Guidehouse, and then we filled it in, so it is really, not super-clear, but the filled-in table is the Guidehouse product describing how we extrapolated from the ETSA to the Pathways study.

MR. RUBENSTEIN: And my question with respect to this table is I just want too confirm that, in light of the changes that were made to the report over the last month, this table is still correct.

MR. WOOD: Hi, this is Cody Wood with Enbridge Gas.

That is correct. This table is still correct in relation to this information and this -- so we use the word "recipe" for how the extrapolation occurred and how it was given to Posterity and then what Posterity took from it.

MR. RUBENSTEIN: Sorry, no, no, I meant -- it is really a question for Guidehouse. They completed the table, explaining essentially how they made some extrapolations, and I just want to clarify that, in light of the changes that they've made to their report, that the contents of the table in this memo are still correct, because you didn't seek to change this interrogatory, and that just because it is an old document, right, not a -- it wasn't asked -- it wasn't a table you prepared in the context of the interrogatories?

MS. ROSZELL: That's correct. So similar to what Michael Brophy was asking us, the approach, which is what's described here, didn't change, so none of the inputs here require an update.

MR. RUBENSTEIN: Okay. Thank you --

MS. MURPHY: Mr. Rubenstein, it's Jennifer Murphy from Enbridge Gas, just to [audio dropout] we did speak to

ENBRIDGE GAS INC.

Answer to Undertaking from
Pollution Probe (PP)

Undertaking

Tr: 184

To confirm for each customer segment in the posterity model that is identified as having ccs applied, what's the percent of the customers in that segment that CCUS is applied to, or if there's other rules applied as well, including any screening done.

Response:

The following response was provided by Posterity Group:

The tables below present the volume of natural gas with carbon capture for the Diversified Portfolio and Electricity Centric scenarios in the year 2038.

- For each scenario, the volume of natural gas with carbon capture is presented by segment.
- For each segment, we identify the regions where the customers consuming natural gas with carbon capture are located, the end-uses that have adopted carbon capture, and the percent of customers in that segment-region combination that have converted these end-uses to natural gas with carbon capture.
- Exhibit 1, Tab 10, Schedule 5, Attachment 1, page 21 of 116 presents the end-use combustion emission factor assumptions for natural gas with carbon capture and storage. The emission factor includes a capture rate assumption for end-uses that have adopted carbon capture.

CCS Conversion in the Diversified Portfolio Scenario:

Segment	Regions	Relevant end-uses	% of Customers applying CCS	Total m3 with CCS
Chemicals Mfg	Union-South	Process Heating (Direct) Process Heating (Water and Steam)	100%	851,845,795
Non-metallic Minerals Product Mfg	EGD-GTA	Process Heating (Direct) Process Heating (Water and Steam)	87%	108,155,249
Petroleum Mfg	Union-South	Process Heating (Direct) Process Heating (Water and Steam)	100%	1,151,935,410
Power and Other Utility	Union-South	Power and Utility	100%	465,439,353
Primary Metals Mfg	Union-South	Process Heating (Direct) Process Heating (Water and Steam)	100%	651,527,987

CCS Conversion in the Electricity Centric Scenario:

Segment	Regions	Relevant end-uses	% of Customers applying CCS	Total m3 with CCS
Petroleum Mfg	Union-South	Process Heating (Direct) Process Heating (Water and Steam)	100%	1,146,482,754

AIRD BERLIS

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April 5, 2023

BY EMAIL AND FILED VIA RESS

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

Dear Ms. Marconi:

Re: Enbridge Gas Inc. ("Enbridge Gas")
EB-2022-0200 – 2024 Rates Application
Updated Guidehouse datasets and related deliverables

We represent Enbridge Gas.

Further to our letter from yesterday, we write to provide a letter from Guidehouse along with their Low Carbon Pathways (LCP) Model input and output datasets and the response to Exhibit JT 1.28 (which includes excel spreadsheets). Guidehouse's summary of the corrections, changes and improvements made is also attached.

For reference, the following files are being provided in a zip file along with this letter:

Datasets responsive to items listed in Guidehouse March 19th letter

- Intervenor Requests 2022-03-24_Submission - Updated 2023-04-05
- Intervenor Requests HP Contribution and Peak Demand 2022-03-31_Submission Updated 2023-04-04

These files will be available on the OEB's webdrawer.

Spreadsheets response to Exhibit JT 1.28

- JT1.28-Attachment-1-Building Space Heating.xlsx
- JT1.28-Attachment-2-Enbridge Transport Industry Demand Decade Forecast.xlsx
- JT1.28-Attachment-3-Enbridge Buildings Demand Decade Forecast.xlsx
- JT1.28-Attachment-4-Loadshapes.xlsx
- JT1.28-Attachment-5-LCP-Inputs.xlsx

- JT1.28-Attachment-6-LCP Results ON Electrification Scenario.xlsx
- JT1.28-Attachment-7-LCP Results ON Diversified Scenario.xlsx
- JT1.28-Attachment-8-Pathway Costs Electrification Scenario.xlsx
- JT1.28-Attachment-9-Pathway Costs Diversified Scenario.xlsx
- JT1.28-Attachment-10-Emissions Results.xlsx
- JT1.28-Attachment-11-Scenario Development Methodology.pdf

These files will be included in Enbridge Gas's undertakings filing tomorrow, and thereafter available on the OEB's webdrawer.

In our letter from yesterday, we proposed some revisions to scheduled dates relevant to the Guidehouse P2NZ Report and the pending report from Energy Futures Group. We will discuss those proposed dates/steps with the most impacted intervenors after they have had the opportunity to understand what is being provided with this letter. We will provide updates as appropriate.

Please let us know if you have questions about this letter.

Yours truly,

AIRD & BERLIS LLP

David Stevens
DS/
c: All parties registered in EB-2022-0200

Guidehouse

April 5, 2023

Via Email: dstevens@airdberlis.com
David Stevens
Aird & Berlis LLP
Brookfield Place,
181 Bay Street, Suite 1800,
Toronto, Ontario M5J 2T9

Re: Enbridge Gas Inc. 2024 to 2028 Rates Application EB-2022-0200

Dear Mr. Stevens:

Guidehouse Inc. ("**Guidehouse**") is writing to provide updated information to Enbridge Gas Inc. ("**Enbridge Gas**") relating to inputs and outputs underlying Guidehouse's Pathways to New Zero Emissions for Ontario Report, dated June 2022 ("**Pathways Report**").

As you know, Guidehouse has been engaged in responding to several undertakings from the technical conference proceedings in EB-2022-0200 (the "**Application**") before the Ontario Energy Board ("**OEB**"). During the process of collating the spreadsheets related to the inputs and outputs of Guidehouse's model used in the Pathways Report in response to undertaking JT1.28, Guidehouse identified certain corrections to the Pathways Report. Guidehouse has taken this opportunity to also include certain enhancements, clarifications and improvements to the modeling data that further refines the information in the Pathways Report. These enhancements, clarifications and improvements arise primarily from questions posed by intervenors at the technical conference held the week of March 20 in this Application.

In an effort to make Guidehouse's input as useful as possible, enclosed with this letter is a summary of the corrections, enhancements, clarifications and improvements that may be shared with the OEB and intervenors to the Application. Furthermore, the requested spreadsheets in response to JT1.28, which reflect the updated inputs and outputs, have been provided to Enbridge Gas and labelled as JT 1.28 attachments 1 through 11, respectively. The Guidehouse deliverables under cover of our March 24 email that were sent to certain interveners and OEB staff have also all been updated and those updates have been provided to Enbridge Gas and labelled as Intervenor Requests 2022-03-24_Submission - Updated 2023-04-05.

For ease of reference, Guidehouse is in the process of preparing an updated report which incorporates the corrections, enhancements and improvements which it expects to deliver to Enbridge Gas by April 21, 2023. If needed, Guidehouse can be available to attend a further technical conference on May 2 or 3, 2023.

Very truly yours,

Guidehouse Inc.

Max J Brady

By: Max J. Brady, Associate General Counsel

Summary of Changes in P2NZ Analysis

Categorization	Change	Type of input/output
Consistency Improvement	Reconciled maximum allowed capacity build out across the scenarios for a number of supply technologies including onshore wind, offshore wind, solar, hydro, and nuclear.	Input Workbook: Supply Technology Costs, Maximum ON New Supply
Consistency Improvement	Reconciled uranium cost assumptions across both scenarios.	Input Workbook: Fuel Import Costs, Supply Technology Costs
Consistency Improvement	Energy efficiency of residential gas-heated homes was increased to 15% energy savings by 2050 instead of 5-7% energy savings, to make the Diversified scenario and electrification consistent	Buildings demand forecast
Consistency Improvement	Performance of gas heat pumps projected to improve by 15% by 2050 in both scenarios, instead of just the Diversified scenario.	Buildings demand forecast
Consistency Improvement	Updated electricity reference case scenario to IESO APS 2019 to be consistent with methane reference case	Buildings demand forecast
Consistency Improvement	Aligned commercial building efficiencies across both scenarios.	Buildings demand forecast
Consistency Improvement	Changed residential space heating equipment and retrofit costs to account for salvage value. This aligns the approach with the capital costs of new supply technologies.	Pathway Cost Results: End User Costs
Post Processing Correction	Total electricity capacity and energy tables/figures now include all electricity generation assets, including Nuclear SMR and Biomass + CCS.	Energy System Results
Model Enhancement	Updated H2 turbine cost to be 115% of natural gas turbine value to reflect likely cost differential between these technologies	Input Workbook: Supply Technology Costs
Post Processing Correction	Ensure inclusion of Nuclear SMR costs in all cost totals	Pathway Cost Results: SupplyTechCosts - Elec
Model Enhancement	Relaxed minimum fuel limit for RNG to allow for better model decision making regarding use of RNG versus fossil methane, while meeting emissions targets	Input Workbook: Annual Fuel Limits
Consistency Improvement	Make Diversified and Electrification Winter Peak Wind dispatch consistent with "no wind" condition, to make scenarios consistent	Input Workbook: Supply Tech Efficiency by Szn
Consistency Improvement	Updated hydro costs in the Diversified scenario to be aligned with the Electrification scenario	Input Workbook: Supply Technology Costs
Consistency Improvement	Updated hydrogen transmission retrofit capital costs to be consistent between intra and inter-regional pipelines	Input Workbook: Infrastructure Costs
Input Correction	Updated nuclear SMR costs to reflect the cost of fuel (uranium) and to have a fixed O&M of 2.5% of the CAPEX cost.	Input Workbook: Supply Technology Costs
Consistency Improvement	Updated the maximum allowed electricity transmission lines in the Diversified workbook to reflect the Electrification scenario.	Input Workbook: Maximum ON New Infrastructure
Model Enhancement	Updated hydrogen storage to better reflect seasonality of H2 storage and improve consistency with methane storage	Input Workbook: Supply Tech Characteristics
Input Correction	Updated discount rate to 4% to be consistent with OEB source	Input Workbook: Financial Parameters
Input Correction	Corrected data entry error in the carbon price in the Electrification scenario.	Input Workbook: Carbon Costs
Input Correction	Updated loadshape for electric vehicles to reference the light duty load profile from NREL.	Light duty transport loadshape
Input Correction	Updated power generator emissions factor to account for efficiency of power plant. This is consistent with the National Inventory Report.	Input Workbook: Supply Tech Characteristics
Model Enhancement	Included hydrogen transmission capital costs for intraregional pipelines into the model inputs (previously only included in post processing)	Input Workbook: Infrastructure Costs
NO CHANGE, Clarification	Emissions rates for fossil methane for power generation and end users contain a small factor associated with upstream emissions associated with extraction and processing. This rate was included in the original P2NZ analysis and has not changed in the updated analysis. Inclusion or exclusion of this factor has a negligible impact on the study results.	Input Workbook: Emissions Rates

ENBRIDGE GAS INC.

Answer to Undertaking from
Environmental Defence (ED)

Undertaking

Tr: 190

With reference to the table in ED-56, for all of those parameters that were produced upstream of the model or downstream of the model to provide the underlying calculations and assumptions, and to do that with the actual spreadsheets that were used, (under advisement.)

Response:

The following response was provided by Guidehouse Canada Ltd.:

Guidehouse provides the files listed in the tables below that were used for the development of inputs to the LCP model.

The table below maps the modeling parameters discussed in JT1.27 to specific files. The inputs represent Guidehouse's research and professional judgement at the time of the analysis.

Modeling Parameter	**Source**	**Submitted Material**
Natural gas price forecast	Determined by Guidehouse, based on Dawn Hub consensus forecast	*JT1.28-Attachment-5-LCP-Inputs.xlsx*
Carbon price forecast	Sourced from ETSA	*JT1.28-Attachment-5-LCP-Inputs.xlsx*
Discount rate	OEB guidance	*JT1.28-Attachment-5-LCP-Inputs.xlsx*
Overall scenario definitions and high-level implications for the buildings, industry, transportation, and power sectors	Determined by Guidehouse, with input from Enbridge Gas subject matter experts	*JT1.28-Attachment-11-Scenario Development Methodology.pdf* *[Note: this document is a historical artifact and snapshot of the intent of these scenarios towards the beginning of the analysis – the exact scenarios including model input parameters evolved over time in the analysis within the framework set forth in this document]*

Modeling Parameter	**Source**	**Submitted Material**
Estimated gas savings in the buildings sector due to retrofit building codes	Sourced from ETSA	*JT1.28-Attachment-3-Enbridge Buildings Demand Decade Forecast.xlsx*
Forecasts of natural gas, RNG, and hydrogen demand for Enbridge customers, for 2020-2038	Sourced from ETSA	*JT1.28-Attachment-5-LCP-Inputs.xlsx*
Forecasts of natural gas, RNG, and hydrogen demand for Enbridge customers, for 2039-2050	Determined by Guidehouse	*JT1.28-Attachment-5-LCP-Inputs.xlsx*
Forecasts of natural gas, RNG, and hydrogen demand outside Enbridge network, for 2020-2050	Determined by Guidehouse	*JT1.28-Attachment-5-LCP-Inputs.xlsx*
Forecasts of annual electricity consumption and peak electricity demand	Determined by Guidehouse	*JT1.28-Attachment-5-LCP-Inputs.xlsx*
Forecasts of conversions of space conditioning and water heating technologies in the buildings sector	Determined by Guidehouse	*JT1.28-Attachment-3-Enbridge Buildings Demand Decade Forecast.xlsx*
Forecasts of conversions of transportation sector technologies	Determined by Guidehouse	*JT1.28-Attachment-2-Enbridge Transport Industry Demand Decade Forecast.xlsx*

Modeling Parameter	Source	Submitted Material
Forecasts of conversions of industrial sector technologies	Determined by Guidehouse	*JT1.28-Attachment-2-Enbridge Transport Industry Demand Decade Forecast.xlsx*
Equipment efficiency ratings	Determined by Guidehouse	*JT1.28-Attachment-3-Enbridge Buildings Demand Decade Forecast.xlsx*
Electric generation capacity expansion	Determined by Guidehouse	*JT1.28-Attachment-5-LCP-Inputs.xlsx*

Guidehouse also provides the following files used in the development of demand inputs.

Modeling Input	File
Demand Forecast	*JT1.28-Attachment-1-Building Space Heating.xlsx* *JT1.28-Attachment-2-Enbridge Transport Industry Demand Decade Forecast.xlsx* *JT1.28-Attachment-3-Enbridge Buildings Demand Decade Forecast.xlsx* *JT1.28-Attachment-4-Loadshapes.xlsx*

Guidehouse provides the following files listed in the table below that are the outputs of the LCP model for both the Diversified and Electrification scenarios.

Modeling Output	Submitted Material
Energy System Results	*JT1.28-Attachment-6-LCP Results ON Electrification Scenario.xlsx* *JT1.28-Attachment-7-LCP Results ON Diversified Scenario.xlsx*
Cost Results	*JT1.28-Attachment-8-Pathway Costs Electrification Scenario.xlsx* *JT1.28-Attachment-9-Pathway Costs Diversified Scenario.xlsx*
Emissions Results	*JT1.28-Attachment-10-Emissions Results.xlsx*

David Stevens
Direct: 416.865.7783
E-mail: dstevens@airdberlis.com

April 4, 2023

BY EMAIL AND FILED VIA RESS

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

Dear Ms. Marconi:

Re: Enbridge Gas Inc. ("Enbridge Gas")
EB-2022-0200 – 2024 Rates Application
Update re Guidehouse Pathways to Net Zero Emissions for Ontario report

We represent Enbridge Gas.

We write to advise the Ontario Energy Board (OEB) and parties about upcoming updates and changes to the Guidehouse report titled Pathways to Net Zero Emissions for Ontario (P2NZ) Study.[1]

In a letter dated March 23, 2023, Guidehouse indicated that it would provide additional model output datasets for its Low Carbon Pathways (LCP) Model in two tranches, with the one on March 24th and one on March 31st. The first set of data was delivered by Guidehouse to several intervenors and OEB staff on March 24th. On March 31st, we sent an email to those parties to advise that there was a delay in relation to the second dataset and that we expected that Guidehouse would provide that material, as well as certain excel spreadsheets in response to Exhibit JT 1.28 on Tuesday April 4, 2022.

In the course of preparing and confirming its model input datasets, Guidehouse has identified certain corrections, and has been working to determine the related implications and impacts. Additionally, it has been determined that other enhancements or improvements will be made by Guidehouse to its LCP Model inputs that arise primarily from questions posed by intervenors at the technical conference. Guidehouse has been working to confirm these items, and then to quantify the impacts to be seen when the items are addressed and the LCP Model is re-run.

While Guidehouse's work is not yet complete, Enbridge Gas recognizes that it is important to inform the OEB and parties of these developments even where the precise impacts and details are not yet available.

[1] Filed as Exhibit 1, Tab 10, Schedule 5, Attachment 2.

At a very high level, we understand that the main items to be updated are the following:

1. Demand forecast changed to be more consistent across scenarios

2. Uranium costs changed to be aligned across scenarios

3. End user costs adjusted to account for salvage value at the end of the study period to be consistent with supply cost calculations

Based on work completed to date, it is expected that the combined impact of the updates will be to narrow the difference between the Diversified and Electrification Scenarios to below $50 billion, with the costs of both scenarios reducing.

Notwithstanding, the conclusion remains that the Diversified Scenario examined is less expensive than the Electrification Scenario. Enbridge Gas continues to believe and assert that the P2NZ Study provides support for showing that a diversified approach to achieving GHG emission reductions targets is as plausible as electrification.

Guidehouse is working to complete the model output datasets for the LCP model, as promised in Guidehouse's March 23rd letter, as well as the spreadsheets referred to in Exhibit JT 1.28. This work includes updates to the model output datasets provided on March 24th. We are aiming to provide these materials tomorrow together with a letter from Guidehouse.

Enbridge Gas plans to file formal updated evidence from Guidehouse about the P2NZ Study addressing Guidehouse's corrections and changes in inputs, process, analysis and outcomes, along with updates to certain interrogatory responses impacted by the changes. This will take some additional time. A proposed updated schedule is set out below.

Recognizing that some parties are very interested in the P2NZ Report, Enbridge Gas believes that it's important to summarize the role that the P2NZ Report plays in the Company's Application. As summarized below, the P2NZ Report does not play a central role in this rebasing application.

- From Enbridge Gas's perspective, the P2NZ Report is filed as only one support for the OEB to be comfortable that there can be an important role for Enbridge Gas and its distribution system in a resilient, cost-effective, low-carbon energy future. Other supports for this conclusion include the Federal Government hydrogen and low-carbon strategies, Provincial Government focus on affordability and on the future role for hydrogen, and the customer engagement that has been undertaken. Of course, the future role for Enbridge Gas is not something that the OEB is specifically charged with determining in this case. However, Enbridge Gas recognizes the electrification-only position taken by some stakeholders on this topic and believed that it was appropriate to have the P2NZ Report prepared and filed in this proceeding.

- Enbridge Gas never expected that its own pathways report would be determinative of any OEB decisions in this case. In this regard, it is important to note that the work of the Electrification and Energy Transition Panel is now underway, and that the Panel's work will be complemented and supported by a Ministry of Energy sponsored independent Cost-Effective Energy Pathways Study.

- Virtually all mention of the P2NZ Report in Enbridge Gas's Application is confined to the Pathways to Net Zero, Safe Bets and Role of Gaseous Fuels portions of the prefiled evidence.[2] Enbridge Gas's requested approvals in these areas are modest, and are generally included in Phase 2 of this proceeding.[3]

None of this is to say that the Company's Energy Transition evidence is not important. Rather, the point here is to anticipate and argue against the position that may be taken by some parties that the process for this case should be suspended until the updated evidence from Guidehouse is received. Enbridge Gas believes that the OEB's current schedule for this Application (as set out in Procedural Order No. 1) can be maintained, with timing and process allowances made for the expert evidence regarding energy transition pathways.

Enbridge Gas recognizes that the information in the P2NZ Report is important to the work being done by the expert jointly retained by ED and GEC – Chris Neme of Energy Futures Group. We do not believe that the P2NZ Report is central to any other intervenor evidence being prepared.

Based on discussions with Guidehouse, Enbridge Gas understands that some time is needed for Guidehouse to prepare and provide updated evidence, in the form of either an addendum or a fully updated P2NZ Report. Additionally, previously provided interrogatory responses from Guidehouse will have to be updated, and Enbridge Gas will have some modest updates to its own evidence (primarily within the Pathways to Net Zero section[4]).

Enbridge Gas proposes that all of the updated evidence would be provided by around Friday April 21st. Of course, Enbridge Gas has no objection to an extension to the April 14th deadline for Mr. Neme's evidence, and subsequent related deadlines related to IRs on that evidence.

Enbridge Gas recognizes that there may be additional and follow-up questions in relation to the updated Guidehouse evidence. The Company believes that it would be most efficient to address such questions through an additional single half or full day of Technical Conference. Enbridge Gas proposes that this could take place on May 2nd or 3rd.

If Mr. Neme is able to then complete and file his expert report by May 10th, all evidence will be available by the start of the Settlement Conference on May 11th.[5]

Enbridge Gas acknowledges that these proposed schedule updates are impactful for the parties most engaged with the Guidehouse P2NZ Report – ED, GEC, SEC and Mr. Neme (those are the same parties who had a pre-meeting with Guidehouse before the Technical Conference to discuss the operation of the LCP Model). Enbridge Gas plans to reach out to these parties to discuss the proposed schedule updates by the end of the week (after the additional model datasets have been provided). We will advise of any further or different proposed approach that is agreed upon through those discussions.

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[2] Exhibit 1, Tab 10, Schedules 5&6 and Exhibits 4, Tab 2, Schedules 6&7.
[3] See Issues List, Phase 2, Section C – Technology Fund & Voluntary RNG Program.
[4] Exhibit 1, Tab 10, Schedule 5.
[5] If Enbridge Gas has interrogatories for Mr. Neme (which the Company can agree to limit to a reasonable level), these could be asked and answered in advance of any oral hearing dates.

Please let us know if you have questions about this letter.

Yours truly,

AIRD & BERLIS LLP

David Stevens
DS/
c: All parties registered in EB-2022-0200

ENBRIDGE GAS INC.

Answer to Undertaking from
Pollution Probe (PP)

Undertaking

Tr: 190

For Guidehouse to confirm what their cost in the model is in relation to CCUS and what elements of CO2 capture, transportation, and storage costs are reflected in that value.

Response:

The following response was provided by Guidehouse Canada Ltd.:

Guidehouse assumed CCS costs of 95 CAD$/t$CO_2$e. A source that Guidehouse used for this assumption includes the costs of capture, transport, and injection/storage.[1]

[1] Gas for Climate (2019). "The optimal role for gas in a net zero emissions energy system", p. 146. Available at: https://gasforclimate2050.eu/wp-content/uploads/2020/03/Navigant-Gas-for-Climate-The-optimal-role-for-gas-in-a-net-zero-emissions-energy-system-March-2019.pdf

ENBRIDGE GAS INC.

Answer to Interrogatory from
Pollution Probe (PP)

Interrogatory

Reference:

"Of the 2,278 investments that were evaluated through Enbridge Gas's IRP Binary Screening, 878 investments passed the screening, relating to $10.4 billion worth of projects that will progress to the technical evaluation."

Question(s):

a) In Enbridge's stakeholder consultation it indicated that only a portion of the projects in the AMP have been screened for IRP purposes. Please indicate when the remaining projects will be screened and how that will be communicated to the OEB and stakeholders.

b) Please explain what passing the screening means and what Enbridge's process is for technical evaluation of projects that passed the screening.

c) For the projects moving forward to an IRP alternatives assessment (e.g. economic evaluation), please provide an estimated date for when the assessment will be complete for each project.

d) Is it correct that 2,278-878 = 1,400 projects in the IRP failed the Binary screening and what is the next steps for those projects?

e) Please provide a copy of the completed screenings for all projects screened out of the 2,278 investments.

Response:

a) Enbridge Gas is targeting to complete technical evaluations for those projects in the AMP that passed the binary screening at the time of the October 31, 2022 Rebasing filing, by Q3 2023.

b) An addendum to the Enbridge Gas AMP will be filed by Q4 2023 which will include IRP updates.

c) The Binary Screening is intended to screen out projects falling under the categories of projects that do not warrant IRP evaluation as noted in the OEB's IRP Decision in EB-2020-0091, pages 47 to 49.

Projects that have passed the Binary Screening will then undergo technical evaluation, which assesses the technical feasibility and likelihood of each IRP alternative (IRPA) eliminating, reducing or deferring the project scope. IRPAs include CNG, Market Based Supply Side, Demand Response, enhanced targeted energy efficiency (ETEE) and other technologies that can reduce or shift peak hour consumption.

Please see response at Exhibit I.2.6-STAFF-81 for information on the process used to complete a technical evaluation for projects that passed the Binary Screening.

d) Enbridge Gas does not have an estimated date for when an economic evaluation will be completed for each project. Enbridge Gas is targeting completion of the economic evaluations for AMP projects that have passed technical evaluation by the end of Q4 2023. The economic evaluation will be completed using the DCF+ Guide filed with the first non-IRP pilot as directed by the OEB's IRP Decision; however, this timing is dependent on the number of economic evaluations to be completed, the complexity of the economic evaluations, the timing of the IRP Plan applications and the timing of the DCF+ Guide review.

e) The number of gas carrying projects passing Binary Screening was 886, and 1,392 projects failed the Binary Screening. In responding to this question, Enbridge Gas realized that "878" in the referenced section was a typo. If during the AMP's update process there is a material change to the scope of a project that has previously failed a Binary Screening, the project will undergo another Binary Screening and technical evaluation. In addition, projects that fail the Binary Screening will have their scopes confirmed at the detailed design phase before filing an LTC application, if applicable, and if the scope has changed materially another Binary Screening and technical evaluation will be completed. In addition, if there is potential for other IRPAs to be implemented due to changes in the IRP framework, these projects will be re-evaluated.

f) Please see response at Exhibit I.2.6-STAFF-82.

Enbridge IRP Website: [Regional Planning & Engagement | Enbridge Gas]

About | Our process | Find projects | Sign up for updates | FAQs

Find Integrated Resource Planning projects in your region

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

Current projects

Parry Sound Pilot Project

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

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

Learn more

BACK TO TOP

Integrated Resource Planning

Regional Webinar

ENBRIDGE
Life Takes Energy®

Eastern Region
Tuesday, April 11, 2023

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.

Agenda

- Engagement process & webinar objectives
- Pathways to Net Zero Study
- Actions/next steps
- Integrated Resource Planning
- Eastern regional overview
- How to stay involved
- Q&A

Engagement process and objectives

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:

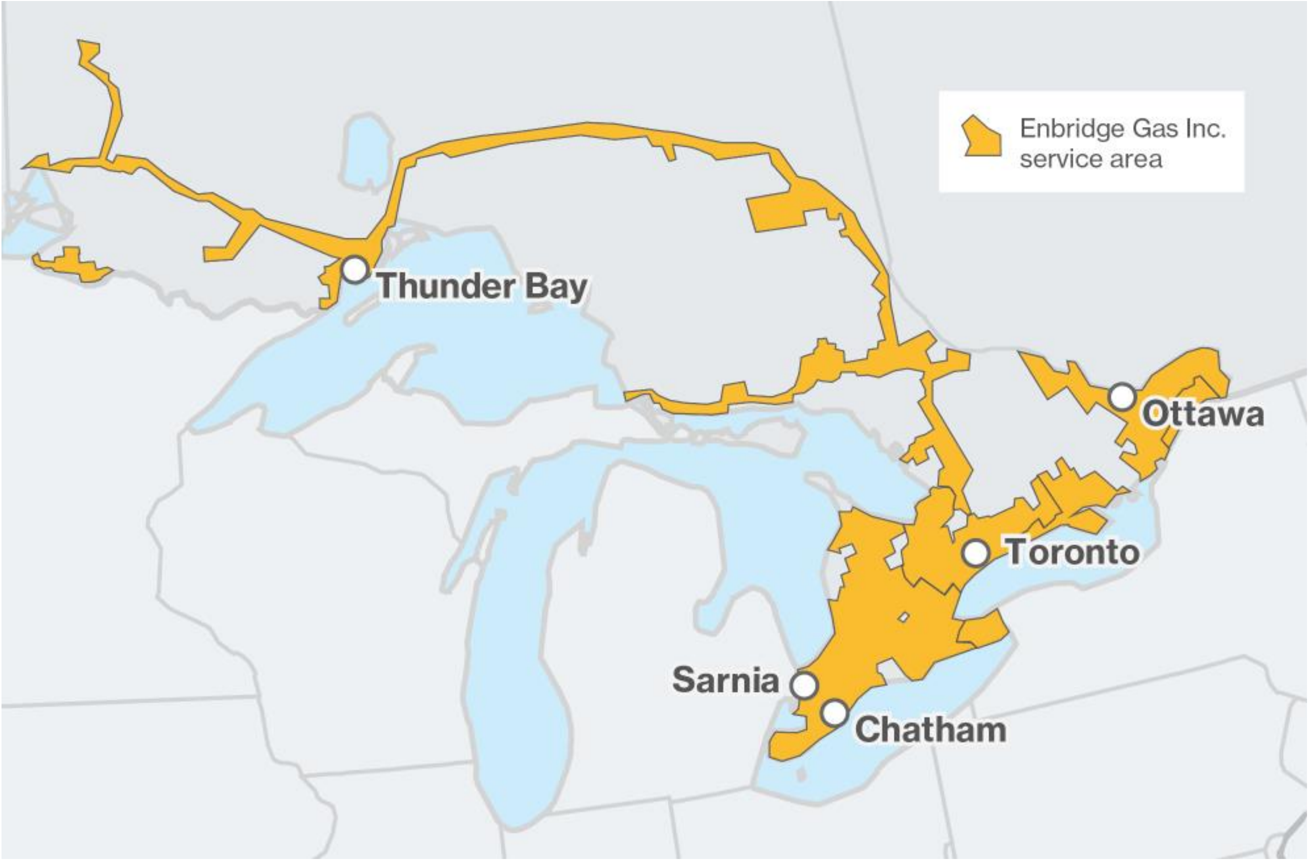
- Highlight the benefits of a Diversified Pathway to Net Zero study in Ontario.
- Introduce Natural Gas Integrated Resource Planning (IRP).
- Provide an update on natural gas planning underway within the region.
- Seek feedback on the demand forecast for the region to confirm current customer growth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

Enbridge Gas Inc.

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.

Pathways to Net Zero Emissions for Ontario

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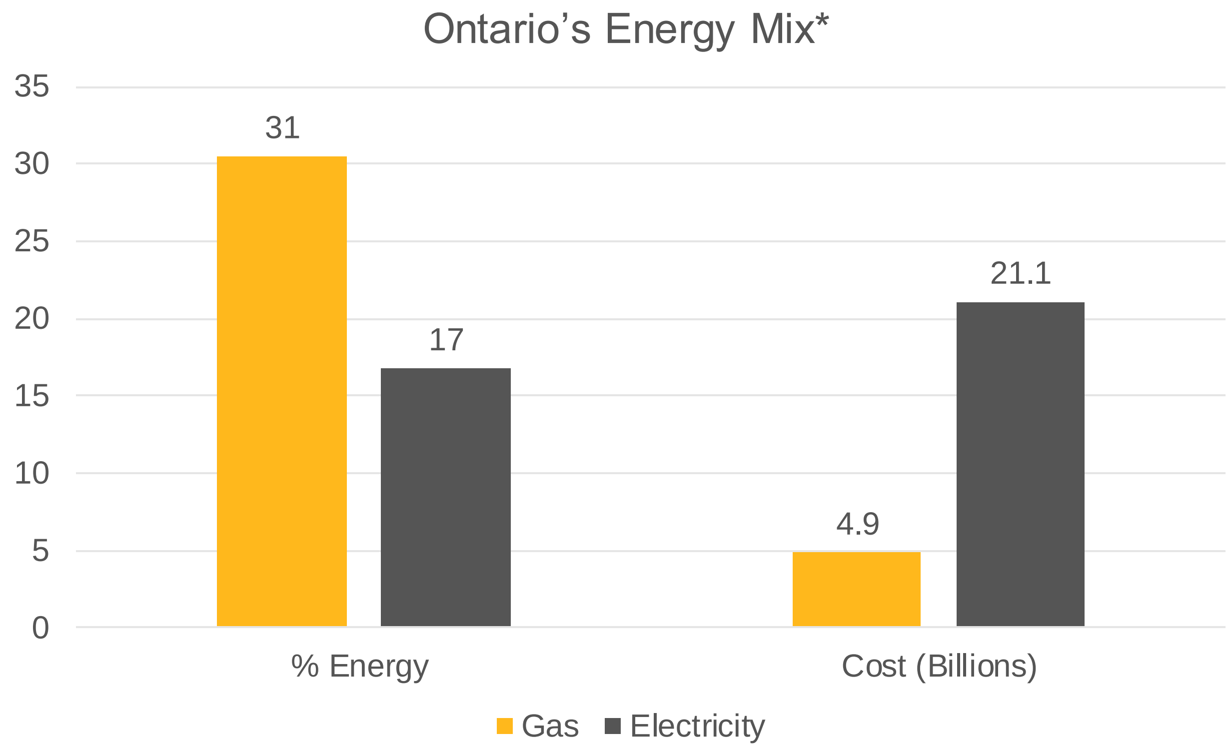
Ontario's energy systems

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.

Enbridge's role in Ontario's energy transition

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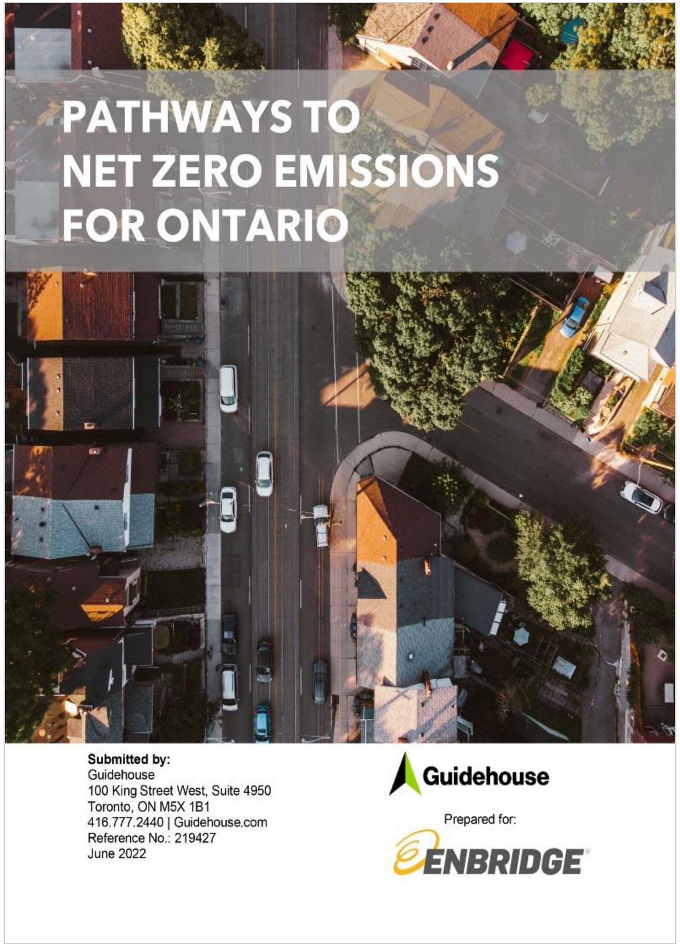
Life Takes Energy

- 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.

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.



Energy transition study findings

A diversified pathway that leverages both Ontario’s gas and electric systems can achieve net zero, with greater:

Reliability

Meets the energy needs of Ontario homes and businesses, even on the hottest and coldest days of the year

Resiliency

Protects against impacts from extreme events, such as weather and cybersecurity incidents

Affordability

Achieves the same outcome as the electrification pathway at a lower cost

Consumer choice

Allows Ontario energy consumers the flexibility to make choices on the path to net zero

Competitiveness

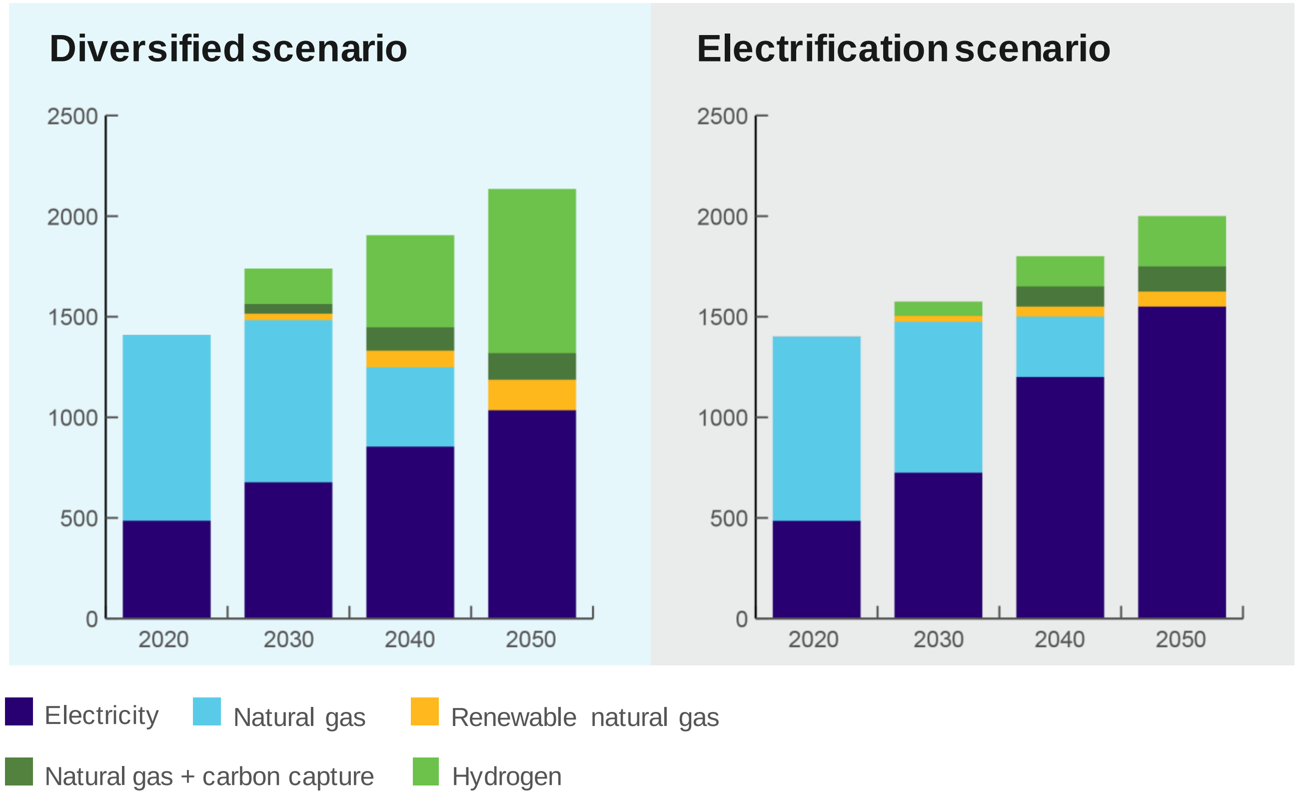
Provides more affordable energy to help businesses stay competitive and thrive.

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



Path to Net Zero

- 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.

Actions/next steps

Life Takes Energy®

Actions to achieve net zero

“Safe-bet” actions to take today to reach net zero:

Maximize energy efficiency

Reduce energy use.

Optimize and coordinate energy system planning

Co-ordinate electric and gas system planning.

Invest in low-carbon gases

Transition to increasing amounts of RNG and hydrogen over time.

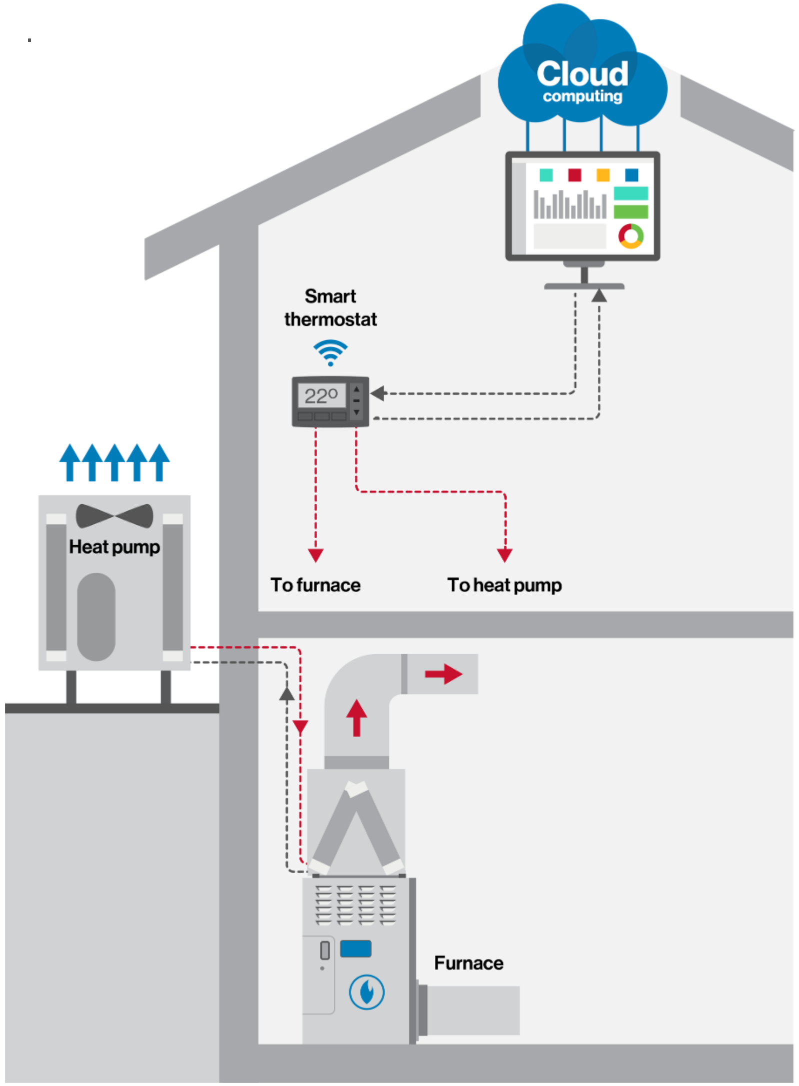
Utilize carbon capture and storage

Invest in CCS for heavy industry and blue hydrogen production.

Actions to achieve net zero

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.



Integrated Resource Planning

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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.

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.

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.

How does IRP support energy transition?

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

How we are planning our system today with IRP

- Demand forecast:
  - Economic forecast
  - Customer additions
- Hydraulic and annual simulation modelling
- Asset Management Plan
- IRP assessment process

Eastern regional overview

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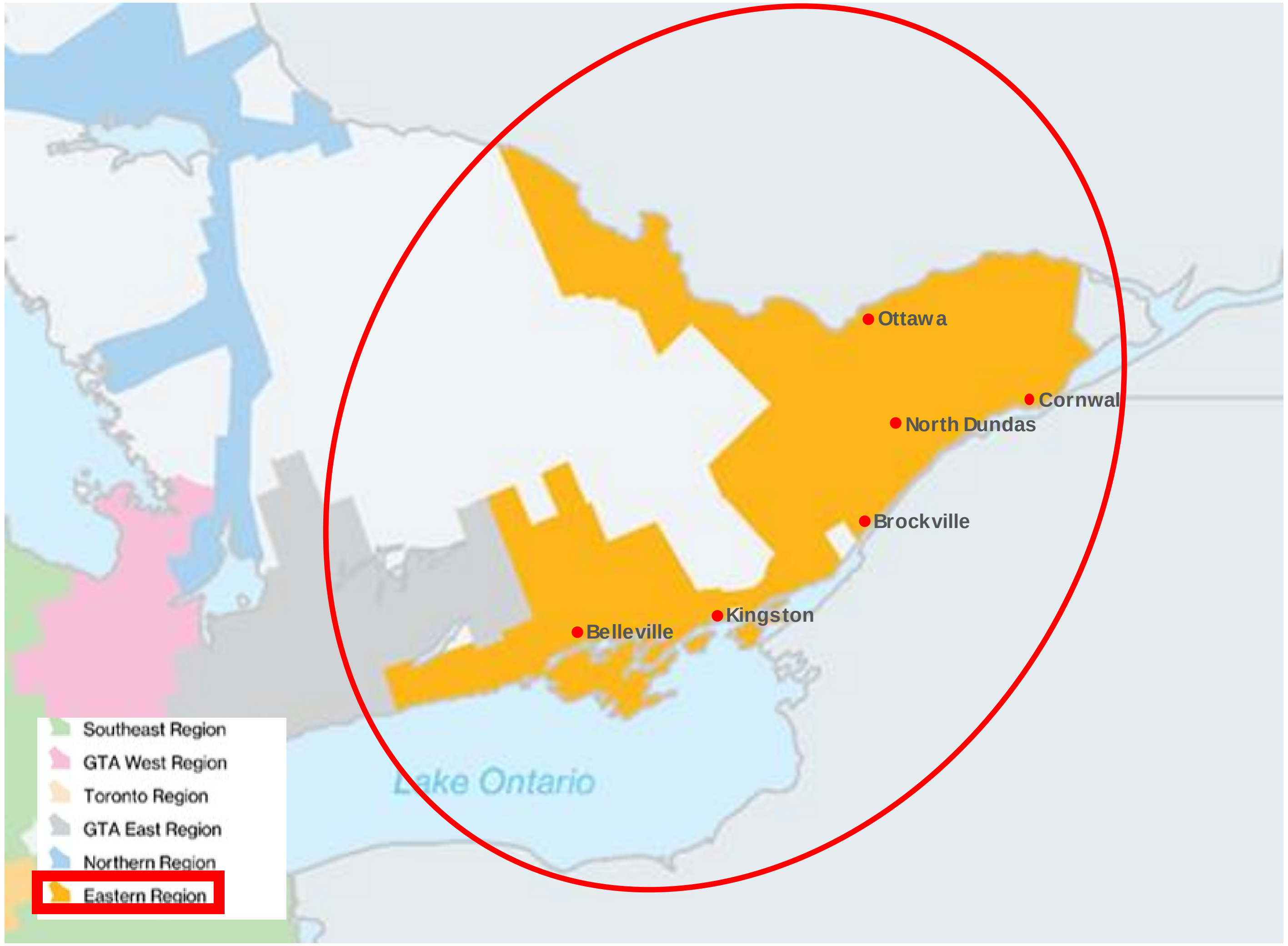
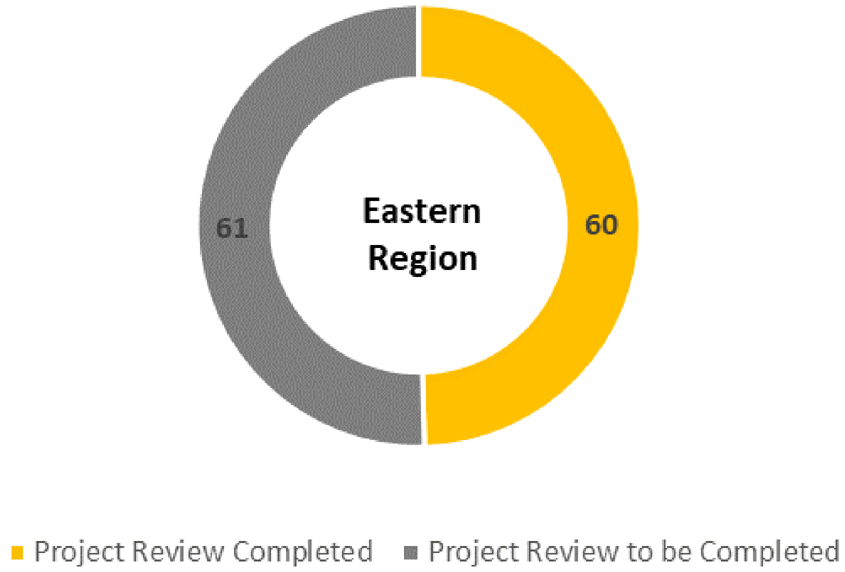
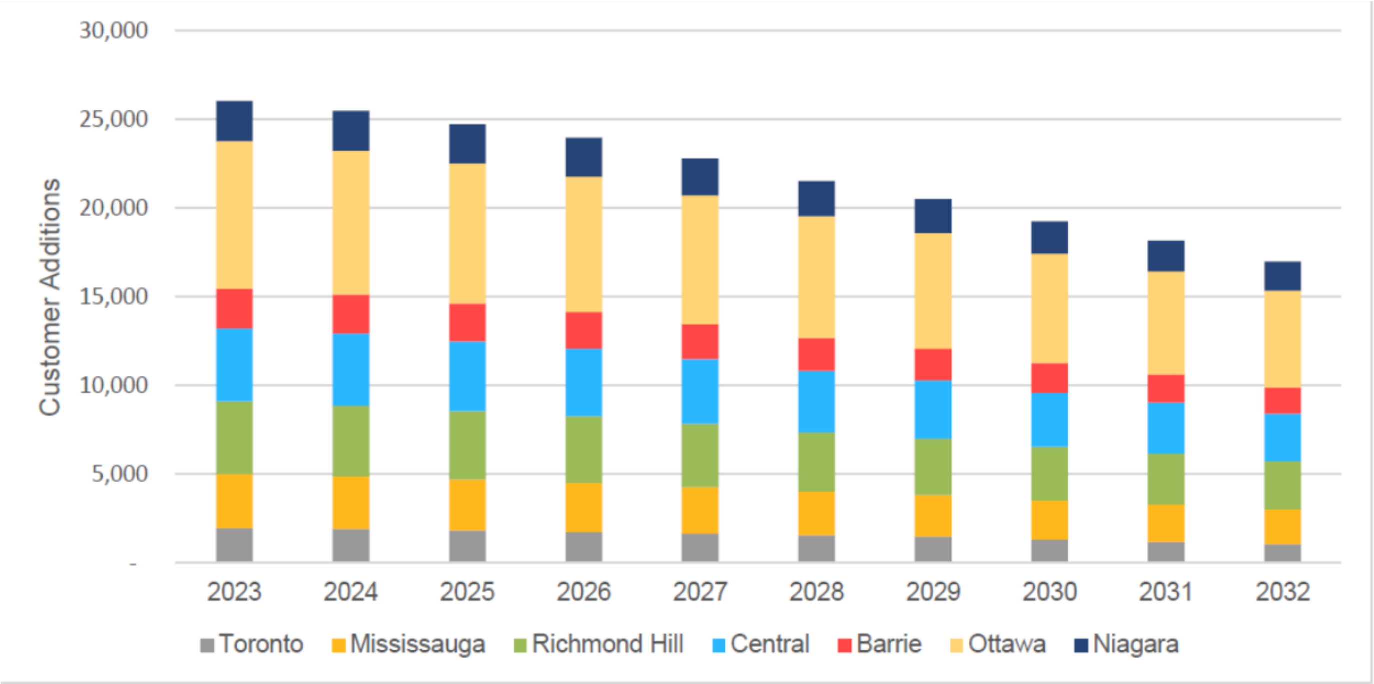
Regional overview: Eastern

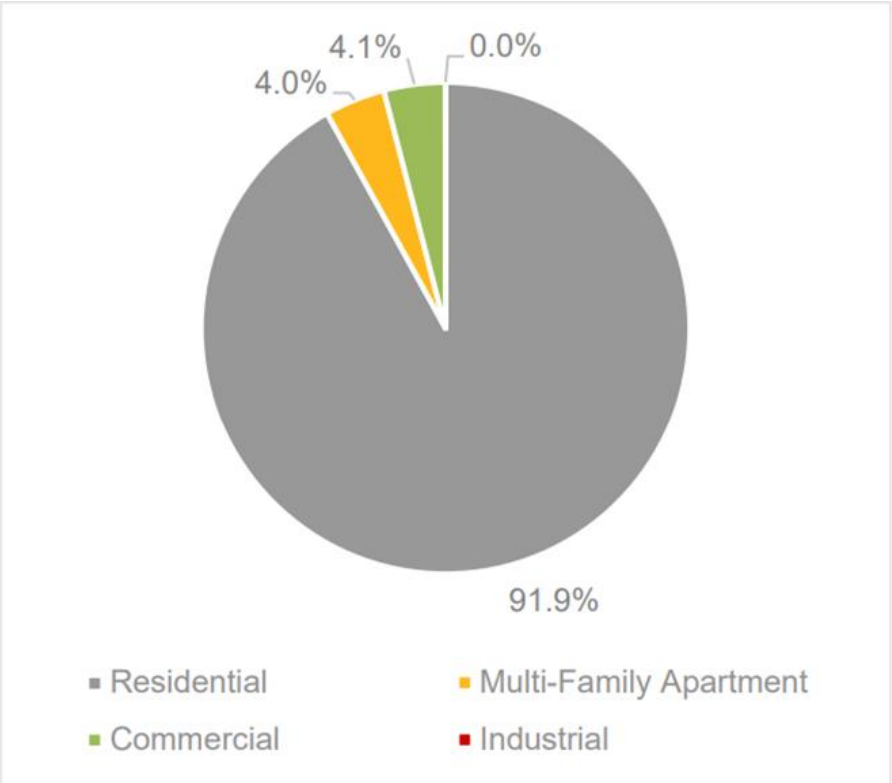


IRP Technical Evaluation Progress

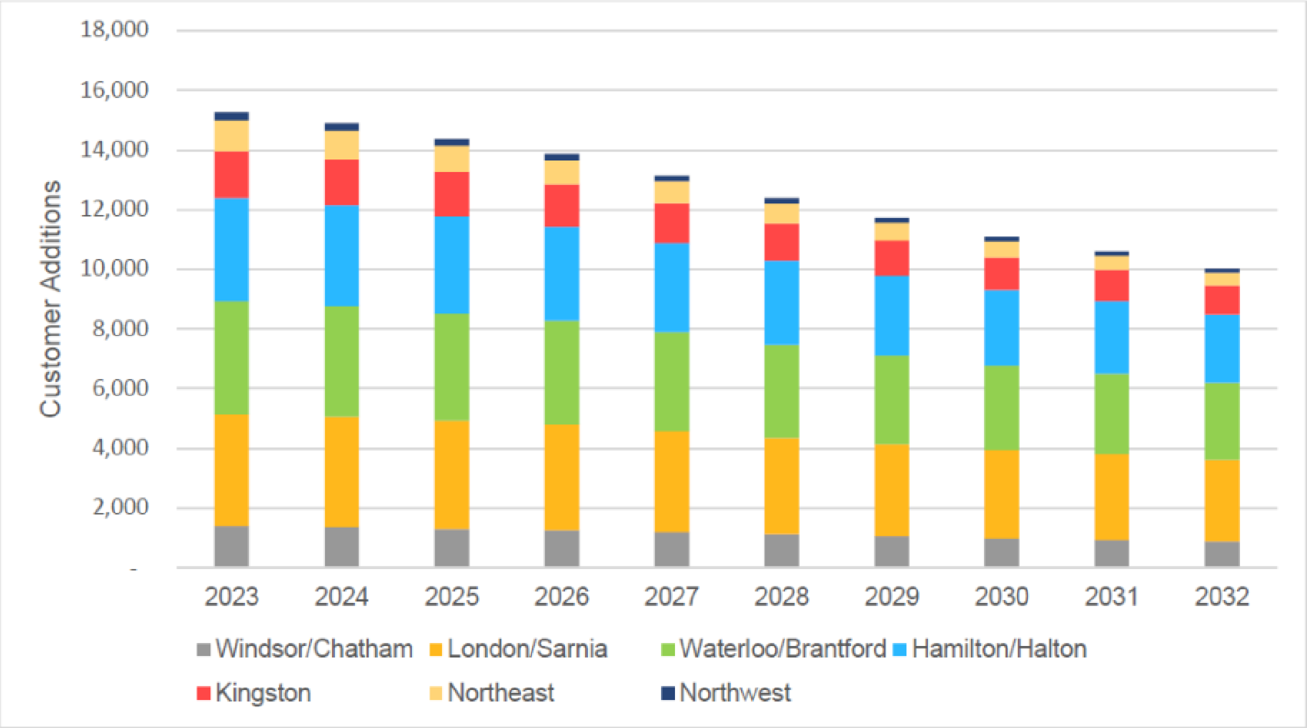


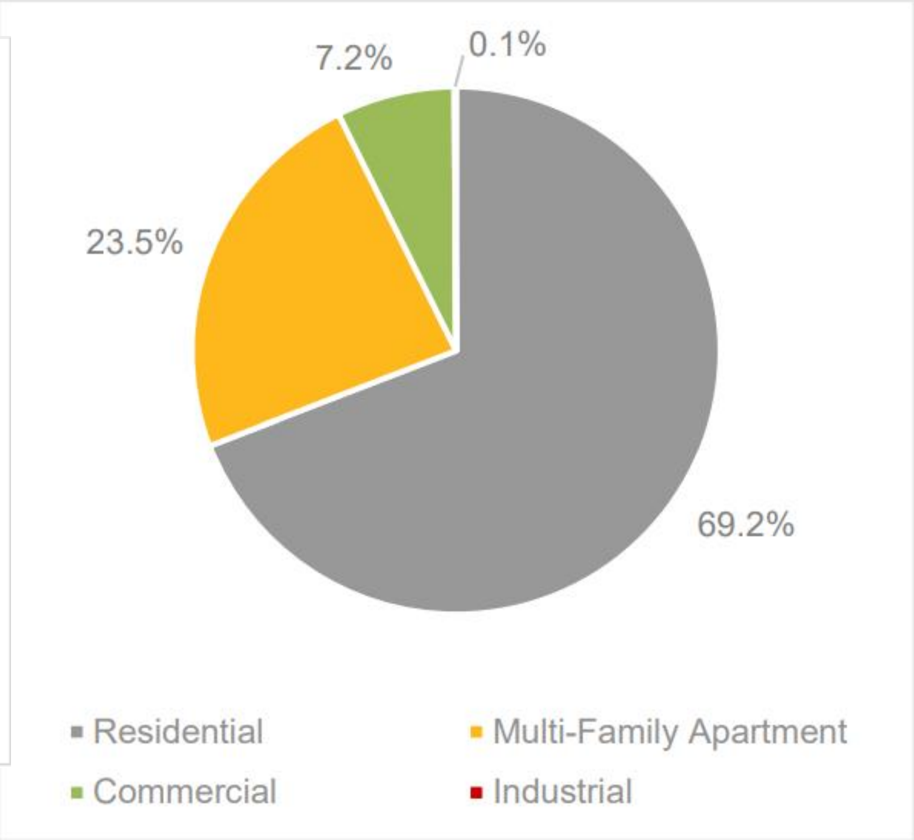
Meeting regional energy needs: customer additions





Meeting regional energy needs: customer additions





Feedback and next steps

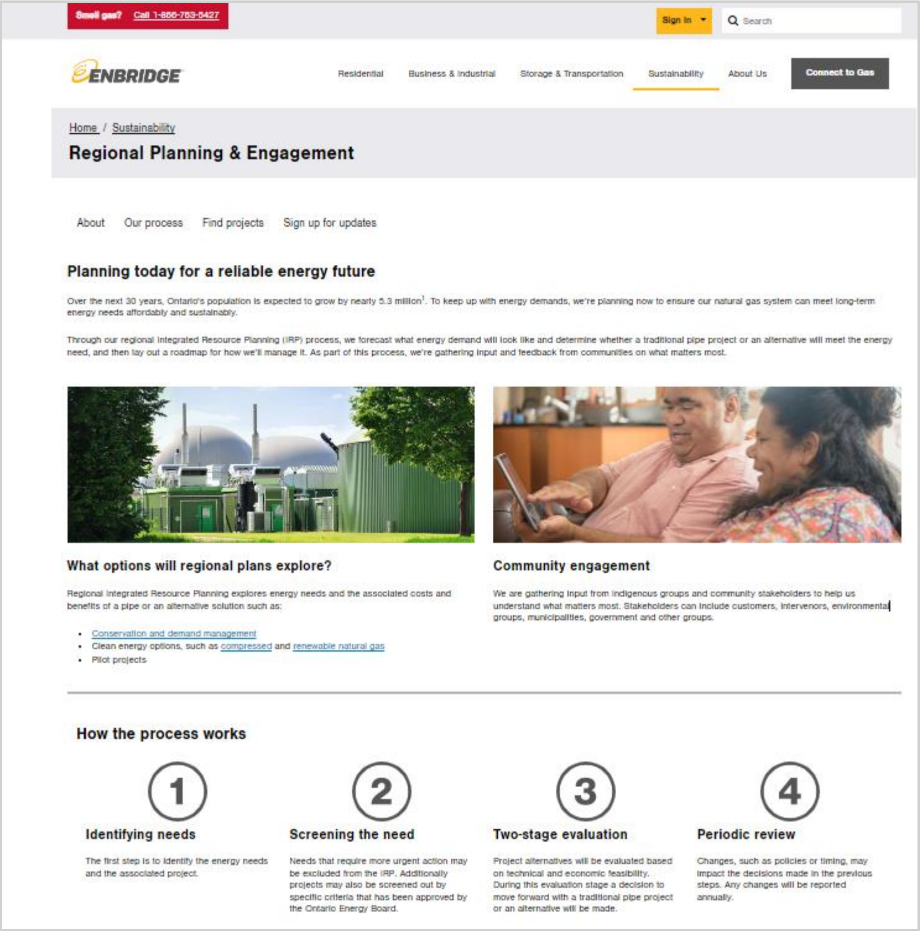
- Feedback from stakeholder engagement initiatives is necessary to inform our IRP activities.
- We welcome feedback on the following:
  - Information that could affect natural gas demand that Enbridge Gas has not considered for this area and/or that you believe Enbridge Gas should be aware of, such as:
    - 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.

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

Q&A

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Thank you

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Life Takes Energy®

Feedback Form: Greater Ottawa Regional Electricity Planning Webinar

From: IESO Engagement (engagement@ieso.ca)

To: engagement@ieso.ca

Date: Wednesday, February 15, 2023 at 04:08 p.m. EST

Thank you for participating in this week's Greater Ottawa regional electricity planning webinar. The presentation materials and the recorded presentation are available for download from the Greater Ottawa region engagement webpage.

Your input is important to us. Please submit your feedback through completing a feedback form, available online and attached to this email, by **February 28** to engagement@ieso.ca. The feedback submissions received and the IESO's responses will be posted on the engagement webpage along with the final Scoping Assessment, by March 20.

Please feel free to contact engagement@ieso.ca if you have any questions.

IESO Engagement

greater-ottawa-20230228-feedback-form.docx
153.8kB

Review of Enbridge Gas Inc. 2022 Integrated Resource Planning (IRP) Annual Report and Update on IRP Working Group Activities

From: Integrated Resource Planning
Technical Working Group

May 30, 2023

Contents

1. Introduction & Overview of IRP Working Group

An Integrated Resource Planning (IRP) Framework for Enbridge Gas was established by the OEB through its *July 22, 2021 Decision and Order* (IRP Decision). The IRP Decision directed the OEB to establish an IRP Technical Working Group (Working Group) and required a Working Group report to be filed in the same proceeding in which Enbridge Gas's annual IRP report is filed.

This Working Group report provides comments on Enbridge Gas's implementation of the IRP Framework in 2022 (as described in Enbridge Gas's 2022 annual IRP report), including member comments or concerns with the implementation of the IRP Framework to date, and also discusses priorities for implementation of the IRP Framework in 2023. The Working Group report also provides a summary of activities undertaken by the Working Group over the previous year.

The Working Group report has been prepared by OEB staff with input from all Working Group members, and approved by all Working Group members, as an accurate summary of the Working Group's activities.[1] Where views expressed in the report do not reflect the views of all members, this is clearly indicated.

1.1. Overview of IRP Working Group

Membership to the Working Group was announced in a *letter* issued by the OEB on December 6, 2021. Members were determined through a *call for nomination* process where the OEB selected seven non-utility members, representatives from the OEB and Enbridge Gas, and observers from the Independent Electricity System Operator and EPCOR Natural Gas LP. The Working Group members have not changed since inauguration and are listed in **Table 1** below. Per the IRP Decision, the Working Group led by OEB staff, was instructed to provide input on IRP issues that will be of value to both Enbridge Gas in implementing IRP, and to the OEB in its oversight of the IRP Framework. Accordingly, a *Terms of Reference* was issued by the OEB on February 17, 2022, after considering the review and input from the Working Group.

Working Group meetings are typically held monthly. Considering the complexity of the discounted cash flow-plus (DCF+) test and as suggested by Working Group members in last

[1] The IRP Technical Working Group includes observers from the Independent Electricity System Operator and EPCOR Natural Gas LP. As noted in the Working Group's Terms of Reference, any materials authored by the IRP Working Group (including this report) should not be considered to represent the views of Working Group observers, or their organizations.

year's Working Group report, a DCF+ subgroup was formed with the first meeting held on July 5, 2022. As such, meetings occurred bi-weekly, generally alternating between the General Working Group and the DCF+ Subgroup. Meeting notes and meeting materials for all IRP Working Group meetings are published on the OEB's website following meetings to allow stakeholders to follow the Working Group's progress.[2] These materials can be found at: https://engagewithus.oeb.ca/irp

Table 1: IRP Working Group Membership

Name	Role
Michael Parkes	OEB staff representative (Working Group chair)
Stephanie Cheng	OEB staff representative
Chris Ripley	Enbridge Gas representative
Whitney Wong	Enbridge Gas representative
Amber Crawford, Association of Municipalities of Ontario	Non-utility member
John Dikeos, ICF Consulting Canada Inc.	Non-utility member
Tamara Kuiken, DNV Inc.	Non-utility member
Cameron Leitch, Enwave Energy Corporation	Non-utility member
Chris Neme, Energy Futures Group	Non-utility member
Dwayne Quinn, DR Quinn & Associates Ltd.	Non-utility member
Jay Shepherd, Shepherd Rubenstein Professional Corporation	Non-utility member
Kenneth Poon, EPCOR Natural Gas LP	Observer
Steven Norrie, Independent Electricity System Operator	Observer

[2] Meeting materials are typically posted online shortly after the meeting. Meeting notes are not typically posted until after the following meeting, to allow for members to review draft notes and identify any omissions or inaccuracies.

2. Review of Enbridge Gas's Annual IRP Report and Comments on IRP Framework Implementation

The IRP Decision notes that the Working Group is expected to review a draft of Enbridge Gas's annual IRP report. The review is coordinated by OEB staff, and Enbridge Gas should provide a draft of the annual IRP report to the Working Group far enough in advance of its planned filing to the OEB to allow the Working Group adequate time to review and comment. The IRP Decision also indicates that the Working Group report should include any comments on Enbridge Gas's annual IRP report, including material concerns that remain unresolved within the Working Group. The Working Group's review took the following steps:

STEP 1:

Enbridge Gas

Provided a draft of its 2022 IRP annual report to the Working Group for review

STEP 2:

Working Group Members

Provided suggested edits/ comments/ clarifying questions

- Member comments were generally aimed at improving the accuracy and completeness of Enbridge Gas's description of its IRP activities, and also suggested some content additions (e.g., listing facilities proceedings where IRP alternatives were considered but rejected, addition of descriptive information on supply-side IRP alternatives to the appendix)

STEP 3:

Enbridge Gas

Revised and finalized its annual report

- Enbridge Gas provided a revised draft of the annual report to the Working Group, documenting how it considered comments from Working Group members
- After a second round of review, Enbridge Gas finalized its annual report. Final determinations as to the contents of Enbridge Gas's IRP annual report were made by Enbridge Gas, not the Working Group

STEP 4:

Working Group Members

Provided final comments on implementation of the IRP Framework including the highest priority items for 2023, for inclusion in the Working Group report

Member comments are discussed further below in section 2.1

2.1. Working Group Comments on Implementation of the IRP Framework

Working Group members (with the exception of observers) were asked the following question:

Having reviewed Enbridge Gas's final annual IRP report's description of Enbridge's IRP activities in the previous year and having also participated on the IRP Working Group, do you have any comments or concerns with the implementation of the IRP Framework to date? What do you think should be the highest priorities for the implementation of the IRP Framework in 2023?

With regards to implementation of the IRP Framework, some Working Group members expressed concerns with the pace of Enbridge's IRP implementation to date, particularly given the need for the OEB to consider the impacts of IRP and the energy transition as they relate to key aspects of Enbridge's active rebasing application, such as Enbridge's forecast capital expenditures during the rebasing term. Members also noted some concerns with Enbridge's engagement with the Working Group, regarding the scope of IRP-related topics discussed with the Working Group, the level of information provided, and the stage at which the Working Group was engaged. Members noted that this limited the Working Group's ability to meaningfully contribute to improving Enbridge's IRP implementation. Priorities for 2023 are discussed in chapter 4 of this report.

More specifics are provided in the comments from individual members in Table 2, and the comments of Enbridge Gas Working Group members follow in Table 3.

Table 2: Individual Comments of IRP Working Group Members

Working Group Member	Comments (optional)
Amber Crawford (non-utility member)	While some progress has been made over the past year, there remain key concerns around whether the Working Group (WG) is being used in accordance with its intended purpose or being used to fulfill a regulatory requirement.

	1. WG brought in too late in the process: In my opinion, by the time feedback was sought from the WG, Enbridge was often too far along in the process for our contributions to have meaningful impact. For example, the WG felt limited in its ability to provide comprehensive and insightful advice around the technical evaluations of the pilots because there was minimal information or analysis on why particular pilots were selected and what justified the absence of others. 2. WG provided with information too slowly: The pace at which information was distributed to the WG has also been concerning given the speed at which Enbridge's Rebasing Application and its plan to add more than $7 billion of capital additions in 2024-2028 is proceeding. 3. WG members not apprised of certain IRP activities: Members of the WG were only apprised of the Kingston IRP after the fact, for reasons that Enbridge has not made clear. Additionally, there was a breakdown in communication, and promotion of the IRP webinar consultations were not shared broadly or with enough notice for most WG members to participate.
John Dikeos (non-utility member)	I generally agree with the feedback that other WG members have provided in terms of opportunities to make better use of WG member expertise and ensure broader communication on all of Enbridge's work related to IRP alternatives. Also, I believe that there is still room for improvement regarding the pace of the development and implementation of Enbridge's IRP pilots. Given the current pace of progress, it is increasingly unlikely that Enbridge Gas will be able to "deploy and implement the projects in time to influence natural gas consumption for the winter of 2023/2024", as noted in the 2022 IRP Annual Report. The timeline for the collection of baseline data further complicates the deployment of these pilots. Although the data that will be collected from the IRP pilots will help refine the evaluation of IRPA projects in the future (e.g., through access to more reliable estimates of costs, peak demand impacts, and customer participation), Enbridge should be encouraged to make parallel progress on the deployment of additional IRPA projects prior to the completion

	of the IRP pilots. Supply-side options, such as CNG, should be increasingly considered as bridge options to help address any near-term performance concerns with demand-side IRPA projects. In terms of upcoming priorities, I am in general agreement that WG members should support the evolution and refinements of Enbridge's processes and tools to consider IRPA projects. I also believe that Enbridge should continue to monitor relevant developments in other jurisdictions and communicate them with WG members so that they can be considered in the evolution of Enbridge Gas' IRPA strategy.
Tamara Kuiken (non-utility member)	{no additional comments}
Cameron Leitch (non-utility member)	Like Dwayne, having had the benefit of Jay and Amber's comments before writing my own, I do not believe there is a benefit in repeating them. Suffice to say, I also agree with their feedback and would defer to Chris Neme and others on another important topic: application of DCF+. There are two focus areas for 2023 that I would add to the feedback from other members. **1. Implementing and Refining IRP using Feedback** Now that the development of an IRP Framework is well underway, and having spent a considerable amount of the WG's time working through process, the next phase will hopefully be focused on implementation and refinement of these processes and tools. Having focused on developing the structure, the detailed application of IRP (and exposure of the WG to the application of it) will provide better insight into the effectiveness of the process. Having reviewed the draft IRP Annual Report prepared by Enbridge, and presuming I've understood Exhibit I.2.6 from the rebasing application correctly, it appears that there are nearly 2,300 investments in the AMP. Of these, 1,392 failed the binary screening with high-level reasons including "Dollar Threshold", "Emergent Safety", or "Timing". The "Dollar Threshold" reason accounts for 1,341 of the failed binary screening items, with forecasted spend ranging from $15.8M to under $1,000.

	Of those investments that passed binary screening, 25 (or approximately 1%) have passed the technical evaluation. And of those, presumably the majority will not pass the final economic evaluation. It is appreciated that the IRP process is relatively new, that additional resources have been hired to manage the process, and that the sheer volume of projects in the AMP requires a considerable amount of effort to evaluate, and so going forward in 2023 I am hoping to (a) see considerable progress toward the identification and implementation of feasible IRPAs, (b) witness the implementation of the processes and tools that the WG had input into so that refinements may be made, and (c) better understand the specific practices that go into defining the Facility Alternative and the IRPA (such as metric-based pricing, assumptions around ETEE/DR uptake, etc.) for the three "levels" of evaluation (binary screening, technical, and economic evaluation). In addition, the investments in the AMP are influenced by the existing customer base and growth, whether replacing/upgrading existing infrastructure or constructing new. Modelling is used to forecast these requirements, and with the changing climate and regulatory environment I would like to better understand how aspects such as global warming and customer upgrades and attrition have been factored into the model. Additionally understanding historical agreement between forecast models and actual system demand may help highlight whether historical perceived need reflects reality. **2. Proposed IRPA Solutions** Enbridge has identified several "conventional" options to consider when evaluating IRPAs, with demand-side options such as ETEE, DR, and supply-side options such as CNG injection. Additionally Enbridge alluded to the implementation of thermal storage and gas heat pumps (in the IRP Report), and the direct installation of these systems in a recent WG meeting. Given the potential challenges in the identification of feasible IRPAs as identified above, efforts to expand the list of opportunities to consider are valuable. That said, how those opportunities are implemented requires further discussion as the direct installation of gas-consuming systems would extend beyond simply bringing the service to the meter.

	Conclusions In 2023 I believe that implementation of IRP and refinement through a deliberate feedback loop, as well as continued scrutiny of the current and former demand modelling that informs the investments in the AMP, are most important.
Chris Neme (non-utility member)	Like many of the other members of the Working Group, I have concerns about how slowly Enbridge has moved to implement the IRP process. I do appreciate that it is somewhat complex and that there is a lot of work associated with assessing the applicability and ultimately cost-effectiveness of IRPAs. I suspect Enbridge is not adequately staffed to enable systemic and routine IRP assessments of hundreds of potential projects. However, as others have noted, given the massive scale of the system investments being proposed in the current AMP – and their implications for gas ratepayers and risks of creating stranded assets because of the energy transition – that cannot be considered an excuse. I also share concerns of others about Enbridge often not using the Working Group to collaboratively consider how best to apply IRP practices rather than informing the working group about decisions that have largely (or entirely) already been made. Going forward, I think there are five areas on which it would make sense to focus Working Group activities: 1. **Refining strategies for the IRPA pilots**. Experience in other jurisdictions suggests that things rarely go exactly as planned for such pilots. There is therefore a need to be closely tracking progress and being prepared to modify strategies quickly in response to market feedback and other factors such as revised estimates of load growth. In my view, this requires at least monthly check-ins initially on the roll-out of strategies. Over time, that could shift to quarterly. Of course, this is only useful, if the Company sees the WG almost as partners in the design, implementation and on-going refinement/adaptation of the pilots. 2. **Refining details of the revised DCF+ test**. There are key elements of our discussion of modifications to the DCF+ test framework that require further work. The devil really is in the details. To give just one

	example, we talked about the need to make estimates of job impacts more accurate and balanced, but haven't moved beyond that concept to actual application of the principle. It would be helpful to actually develop specifics for this issue, commission a jobs and economic development study to quantify things as other jurisdictions have, etc. This applies potentially to other DCF+ issues/impact categories too. 3. **Working through specific details of the Company's binary screening and, perhaps more importantly, its technical screening of IRPA applicability**. It would be super helpful to get more specifics from Enbridge on how these screens are being applied and for the WG to work through potential modifications to the Company's approach to such screening where appropriate and applicable. This needs to be done while the pilots are being implemented (not just afterwards) as we cannot afford to wait until the pilots are complete to revise current practices or we will be too late to influence hundreds of millions or billions of dollars of investments. 4. **Penalties and incentives for IRPAs**. I strongly suspect that Enbridge (like other utilities) will respond much more expeditiously and effectively to IRP requirements if shareholder dollars are at stake. Thus, I personally think it is important that there are both penalties for failing to adequately review IRPAs (or to review them early enough to enable them to proceed if cost-effective) and incentives for pursuit of IRPAs that are effectively deployed. The WG should endeavor to identify a short list of options and, ideally, a consensus recommendation for the Board (if not, at least a summary discussion of pros and cons of different options) on such penalties/incentives. I believe that the Board's order in the Gas IRP proceeding suggested this is a topic the WG should take up. Seems like it needs to happen soon. 5. **Modifications of Gas IRP Framework and/or approach to application of the framework to address the energy transition**. The current rebasing case has made clear that major changes are coming. We may disagree about exactly what those changes will be or how fast they will come, but they will be major in any case and are coming. This has huge

	implications for consideration of IRPAs. For one thing, I think at a minimum that IRPAs should be assessed under several different demand growth futures, so that we better understand the risks of creating stranded assets and better assess the risk mitigating potential of IRPAs. I appreciate that the above list is substantial, and it is probably not possible to tackle all of it within the current WG structure and process. But it is also all urgent. So maybe there needs to be a discussion about how to modify the WG process to better enable addressing more of these fundamental issues. as long as it addressed all of the aforementioned issues.
Dwayne Quinn (non-utility member)	Having the opportunity to follow Jay and Amber, I can state that I fully support their expressed concerns and will not restate them. Instead, we provide specific concerns as examples of the problems identified in their submissions. Many times, the WG asked about getting information on IRP processes or projects and were told that these items were "under review" or still being "developed" by EGI. These requested items were not being released until "signed off" by all of the pertinent areas of EGI. This approach clearly inhibited the opportunity for the WG to contribute to the development of approaches or projects where ideas from the group could have enhanced the process and outcome. One specific example is the Parry Sound project. Several times, I suggested ideas or requested information and it took months to get responses. When I did get information, it was limited to my specific ask and was not complete leading to my speculation on approaches (I would guess or estimate to get the requested information by being corrected). Three months ago, after making some progress, I was told that once EGI finished their USM model, it would be a good idea to have a meeting. That meeting has not been scheduled.
Jay Shepherd (non-utility member)	The Enbridge approach to IRP continues to be a disappointment, although there have been improvements over the 2022 year. ***Role of the Working Group.*** Enbridge and the Working Group appear to have different views of the role and value of

	the Working Group. The members of the WG generally agree, I think, that we should be seen as an expert resource that Enbridge can tap to a) improve the quality of their approach to IRP, and b) increase the speed with which they implement to meet the expectations of their customers and the OEB. That has not been the experience to date. Instead, the WG has been treated as a regulatory requirement that Enbridge must meet, but only on topics specifically set out in the IRP Decision. Information has been doled out in a limited manner, and input sought on only a few narrow items (pilot projects and DCF+, mainly). Thus, at no time did Enbridge share their strategic planning for the rollout of IRP with the WG. Effective use of the resource would have meant sharing final copies, or even drafts, of their staffing plan, their stakeholdering and communications plans, their technical assessment process, and their economic evaluation process, to name just a few components. None of that was done, despite the fact that around the WG table there are people who have considerable experience in those areas. For example, early on Enbridge made a decision that, in adding FTEs for IRP work, they would add those new people to the non-IRP functional areas, rather than create a cohesive team focused on IRP and interacting as a team with the other functional areas. The WG found out about this as a *fait accompli*, already finalized and implemented. Both staffing strategies have strengths and weaknesses, and the Enbridge approach may or may not be the best one. It is, though, surprising that the experience of the WG members was not tapped to provide input to that important decision. Another example is the technical evaluation process. Since the beginning the WG members have been asking for information on that process so that they could provide input. At this point, with the AMP going before the OEB in the rebasing proceeding in just a few weeks, we still do not have details on this process. This is particularly problematic since so few of the AMP projects have passed the technical evaluation. A more effective approach to the IRP function at Enbridge would have been to develop a comprehensive internal business plan/strategy for that initiative, and share that at all stages of the drafting with the WG. To the best of our knowledge, nothing like that has even been prepared, let

	alone shared, and certainly the Enbridge IRP strategy is opaque. It is also worth noting that Enbridge did implement one IRP in 2022, the Kingston project. The WG was not involved in that process, finding out about it only after the fact, for reasons that Enbridge has not made clear. ***Continued Resistance to Implementing Meaningful IRP.*** The pace remains very slow. In parallel, the Rebasing Application is proceeding at full speed, with Enbridge's plan to add more than $7 billion of capital additions in 2024-2028 a key element of that application. It now appears clear that the OEB will be required to make a determination on that application, and that capital plan, without any information on the ability of IRP to make a dent in that spending. This WG report itself will be made public the day before the ADR in that application, and less than a month before the oral hearing. At that point, the WG will have had limited ability to look at how IRP is being done this year, and the AMP will not include any IRP alternatives. This may have the effect of deferring the disciplined consideration of actual IRP implementation by the OEB for up to five more years. This is all against the backdrop of the Energy Transition, perhaps the most overarching issue in the Rebasing Application. We have seen no indication that Enbridge has any sense of urgency in their IRP rollout, despite the increasing intensity of the Energy Transition debate. It is as if the continuing additions to rate base, month after month, can continue indefinitely, with no "brakes" being applied through IRP or anything else. At the current pace of IRP planning and implementation at Enbridge, I believe it is unlikely that even 1% of the $7 billion of capital additions over the next five years will be avoided by IRP alternatives (i.e. less than $70 million). ***Stakeholder Engagement.*** It is of concern that members of the WG that would have attended community meetings hosted by Enbridge found that they were not invited, or that their invitations were "lost". This is particularly problematic in the context of municipal engagement, since past reports have suggested that stakeholder engagement could be used to "sell" more continued use of natural gas rather than other alternatives. Further, Enbridge presentations to municipal representatives routinely promote the gaseous fuels model for

	getting to Net Zero, and downplay the alternative, increased electrification. It would be helpful if Enbridge maintained a schedule of community engagement activities for IRP that was available to WG members – and members of the public - well in advance, so that those who wish to attend could do so.
Mike Parkes/ Stephanie Cheng (OEB staff representatives)	In OEB staff's view, Enbridge Gas made significant progress towards implementing the IRP Framework in 2022, as compared to 2021, although to date this has only resulted in one instance where Enbridge Gas has used IRP alternatives to defer a facility project (Kingston Reinforcement Project, section 6 of Enbridge Gas annual IRP report). In particular, Enbridge Gas's integration of IRP assessment into its Asset Management Plan (section 3) and study and proposal for interruptible rate design (section 9), are important steps towards implementing the IRP Framework in alignment with the IRP Decision,[3] as are the work done with Working Group input to refine IRP pilot proposals (section 4) and enhance the DCF+ test (section 10), although Enbridge Gas's key milestones for these items will not be reached until later in 2023. Enbridge Gas should build on this work and further leverage the expertise of the Working Group in 2023. OEB staff provides the following additional comments: • **Transferring Learnings from IRP Pilots:** In last year's comments, OEB staff noted that Enbridge Gas was not on track to have pilots deployed by the end of 2022, which was the expectation of the IRP Decision, and that it would therefore be important for Enbridge Gas to make use of learnings from the pilots while they are still in-flight, to inform Enbridge Gas's broader consideration of IRP alternatives in system planning decisions. As this year's annual report shows, the timing of pilots has been further delayed, and Enbridge will be filing its pilot application in June 2023. OEB staff recommends that Enbridge provide regular public updates on pilot progress, so that, in the context of non-pilot proceedings (e.g., Leave to Construct applications, IRP Plans), the OEB and other parties will have an up-to-date understanding of what Enbridge is

[3] Both of these items are part of the evidence in Enbridge Gas's rebasing proceeding (EB-2022-0200), which is active at the time of writing. OEB staff's acknowledgement of their importance for the IRP Framework should not be interpreted as taking a position on the substance of Enbridge's actions and proposals as they relate to the approvals requested in the rebasing proceeding.

	learning from its pilots, and how this has informed Enbridge's planning determinations. • **Scope of Input on Enbridge Gas's IRP Activities by the IRP Working Group:** In last year's comments, OEB staff noted a concern that the Working Group had not been provided with substantive advance details of IRP-related proposals in Enbridge Gas's rebasing application, and that any review by the Working Group in advance of Enbridge Gas's filing would be quite limited. This proved to be true, with limited consideration by the Working Group of some aspects after the filing of the rebasing application (e.g., IRP screening process applied to the Asset Management Plan), and no consideration of others (e.g., interruptible rate design). OEB staff recognizes that the timing of the rebasing application made it difficult for Enbridge Gas to seek advance input from the Working Group on all IRP-related proposals; going forward, OEB staff encourages Enbridge Gas to broadly share information on IRP-related developments with the Working Group, and work collaboratively with the Working Group to identify and prioritize areas where Working Group input at early stages will add the most value. • **2023 Priorities:** OEB staff generally agrees with the 2023 IRP priorities identified by Enbridge Gas. In particular, OEB staff agrees with the Working Group that understanding, refining, and improving the evaluation process used by Enbridge as it continues its IRP evaluations of system needs in the Asset Management Plan should be a high-priority item for Enbridge Gas and for the Working Group. Among the list of items in the IRP decision that were not identified as 2023 priorities by Enbridge Gas, OEB staff also believes that some consideration of performance metrics for IRP (at the level of an individual IRP Plan or for Enbridge's system-wide use of IRP) by Enbridge Gas and the Working Group may be valuable. This could include consideration of the metrics for non-wires alternatives discussed in the OEB's Filing Guidelines for Incentives for Electricity Distributors to Use Third-Party DERs as Non-Wires Alternatives, and whether they are applicable or useful for natural gas IRP.

Table 3: Comments of Enbridge Gas IRP Working Group Members

Working Group Member	Comments (optional)
Chris Ripley/ Whitney Wong (Enbridge Gas representatives)	Enbridge Gas values the technical expertise and experience of each IRP TWG member and appreciates that their technical input can help facilitate an effective implementation of the OEB's IRP Decision. Enbridge Gas understands, via discussion at the IRP TWG and from the above noted comments, that TWG members have concerns with the pace by which Enbridge is implementing the IRP Framework Decision, as well as the scope and timing of information that Enbridge Gas has brought forward to the IRP TWG for input. Implementing IRP into a utility's established asset management planning process, as seen across other jurisdictions, is complex and time intensive. Over the course of 2022, Enbridge Gas has worked with the IRP TWG to confirm its IRP Pilots and to evolve the DCF+ Test. In addition, to ensure progress is not slowed, Enbridge has evolved its asset management planning process via the development of draft IRPA assessment processes, and by drafting and trialing stakeholder engagement processes for its seven planning regions. Enbridge believes this progress is reasonable given the many facets of Enbridge's Planning process that must be evolved, and that the advancement has happened in parallel to Enbridge Gas's 2024 Rebasing application and proceeding. In terms of the scope and timing of information that Enbridge Gas has brought forward to the IRP TWG for input, Enbridge has focused its time with the TWG on the areas that the Board noted as a priority, the IRP Pilots and the DCF+ Test. With significant progress made on these initial priorities, Enbridge Gas has highlighted the topics it would like to focus on with the IRP TWG in 2023 and these priorities are aligned with most of the topics that the TWG would like to have input into. There are a number of topics that TWG members would like to discuss that indicates some members view the scope of the TWG as more expansive than what Enbridge Gas understands it to be from the Board's IRP Decision and from the TWG's TOR. Enbridge Gas has included comments below to further address these key concerns as well as other comments that have been noted above.

	2022 IRP TWG Priorities as defined by the IRP Decision and the IRP TWG Terms of reference (TOR) The role of the IRP TWG was defined in both the IRP Decision and in the Terms of Reference (TOR). The OEB's IRP Decision indicated that "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.[4]" These initial priorities were reiterated in the Terms of Reference (TOR), "The OEB expects that the first priorities of the Working Group will be: Consideration of IRP pilot projects to better understand how IRP can be implemented to avoid, delay or reduce facility projects. Enbridge Gas is expected to select and deploy two IRP pilot projects by the end of 2022. Enhancements or additional guidance in using the Discounted Cash Flow-plus economic evaluation methodology to assess and compare the costs and benefits of using either facility solutions or IRP alternatives to meet system needs.[5]" Given this clear direction from the Board, the Pilots and the DCF+ Test have been the initial focus of the TWG and, therefore, what Enbridge has initially focused its TWG content on. In 2022, Enbridge was committed to developing and contributing a great deal of relevant TWG content and to obtaining the expertise of the TWG on these topics. To ensure there was sufficient time allocated to gathering input, Enbridge advocated to move the TWG meetings from monthly to bi-weekly. In addition, as outlined within its 2022 IRP Annual Report, Enbridge has identified new/additional topics that it would like the IRP TWG's input on given the status of the two initial areas of focus. This level of engagement does not align with some of the above noted TWG member comments, most specifically, comments noting that Enbridge treats the TWG process solely as a regulatory requirement. An overview of the work Enbridge Gas undertook in 2022 on the IRP Pilots and the DCF+ Test has been highlighted in its 2022 Annual IRP Report. To address the above noted comments regarding the IRP Pilots, Enbridge has added some additional details below.

[4] EB-2020-0091 Decision and Order, page 7
[5] IRP Working Group - Terms of Reference (oeb.ca)

	IRP Pilots In 2022, Enbridge Gas presented and requested input and expertise on a number of specific proposals and concepts related to the IRP Pilot projects, including: pilot objectives, pilot project selection criteria, eight potential pilot projects potential IRP alternatives for the projects and rationale for the selection of the two projects through a decision matrix. Throughout 2022, Enbridge continued to engage the TWG on the pilot projects to discuss the IRP alternatives considered and chosen, pilot budgets, ETEE programming, approach to cost benefit test for the pilot application, pilot stakeholder meeting objectives and outcomes and overall pilot project timing. The TWG reiterated to Enbridge Gas throughout 2022 that Enbridge Gas is responsible for the selection and implementation of the pilot projects. ***Advancing IRP Implementation in Parallel to working through the IRP TWG's Initial Areas of Focus (Pilots and DCF+ Test)*** While the IRP TWG has focused on the Board's initial two priorities, Enbridge Gas has moved other IRP implementation activities forward to ensure progress is not slowed. Working on other activities does not mean that TWG member contributions made in 2023 won't have a meaningful impact as some members have expressed. Rather, it means that Enbridge Gas is in a position to bring forward draft processes, for example the draft technical evaluation process, for both discussion and input. This feedback can and will be considered as these processes have and will continue to be iterative. Some IRP TWG members do not feel Enbridge Gas has moved fast enough with regards to implementing IRP; however, some members also believe that Enbridge Gas has moved things forward without fulsome consultation with the TWG. These two requests, to move more quickly and to bring all IRP activity underway to the IRP TWG would not have been feasible in 2022 given the magnitude of IRP implementation work required and that the IRP TWG had to move to biweekly meetings to create the capacity to address the two areas of focus identified by the Board. A complete list of areas that Enbridge Gas focused on in 2022 has been highlighted in its 2022 Annual IRP Report. To

	address comments made above by IRP TWG members, details regarding some of these areas are noted below. *Stakeholder engagement roll out:* The stakeholder engagement plan is being implemented per the Boards Decision [6]. As outlined in more detail within Enbridge's 2022 Annual IRP Report, Enbridge Gas focused its 2022 stakeholder engagement efforts on building its web page and webinar hosting capabilities, marketing to external stakeholders to garner interest and participation in the IRP / regional planning initiatives and on engaging municipalities to ensure awareness and understanding of IRP. The regional webinar sessions were rolled out in early 2023. TWG members have indicated that they were not invited to these webinars and that it would be helpful if Enbridge maintained a schedule of community engagement activities so that those who wish to attend could do so. As noted in the 2021 Annual Report and as socialized with the TWG during the TWG meetings starting in January 2022, the IRP website is the primary site for all communications related to upcoming IRP initiatives, pilot projects, regional webinars and presentations. It was noted in TWG meetings that dates of upcoming sessions would be posted on the web site and that to receive notifications and updates, individuals must register on the site, if not registered an individual would have to check back periodically. The IRP Regional Planning web page can be accessed here: Regional Planning & Engagement | Enbridge Gas Unfortunately, as sometimes happens when new digital initiatives are launched, Enbridge experienced a small technical issue that resulted in seven registrants, including one TWG member, not receiving emails regarding upcoming regional engagement sessions. Once notified of this issue Enbridge was able to rectify the situation immediately. Enbridge notes that although some TWG members have registered on Enbridge Gas's IRP web page no other non-utility TWG members attended the webinars. To ensure those that can't attend the IRP webinars have access to the information presented, the regional

[6] EB-2020-0091 Decision and Order, page 66

	presentations are posted on the IRP web page[7]. These presentations include an overview of Energy Transition to provide context about how Enbridge forecasts and plans its distribution system. Enbridge Gas disagrees with some working group members' comments that the inclusion of content related to Energy Transition is meant to sell more and/or continued use of natural gas, rather Enbridge Gas believes it provides context as to how IRP fits into the Energy Transition. *Ongoing IRP Alternative Assessments:* As noted above, Enbridge Gas has drafted an IRP Technical Assessment process. This draft process was iterated continually as Enbridge moved through its first AMP IRP review process. Despite this process occurring in parallel to the 2024 Rebasing proceeding, Enbridge Gas continued to progress its review and as it was able to provide additional information throughout the rebasing interrogatory and technical conference phase, it did so[8]. Enbridge Gas expects that with each AMP cycle the process will be refined, with input from the TWG and become more seamless and less time intensive. *Non-Pilot IRP Plans* In moving through its first IRP Alternative Assessment process Enbridge identified and implemented its first feasible IRPA, the Kingston Creekford project, as outlined in the 2022 Annual Report Section 6 – Non–Pilot IRP Plan Updates and in Enbridge Gas' 2022 Annual Deferral Disposition proceeding, Exhibit c, Tab 1. Some TWG members have noted that they were not, and had expected to be, made aware of the Kingston Creekford IRPA prior to its implementation. Enbridge Gas agrees that when identified IRPAs include new or unusual circumstances or technical considerations it would benefit from consultation with the IRP TWG. Enbridge Gas notes, however, that the Kingston project's IRP alternatives evaluation and implementation were straightforward. Enbridge Gas agrees with TWG members' comments regarding continuing to make progress on non-pilot IRP Plans

[7] Regional sessions were held on April 4, 6, 11, 13, 18, 25 and May 4, 2023 [Regional Planning & Engagement | Enbridge Gas]

[8] Section 3 – Integrated Resource Planning Alternatives (IRPAs) Evaluation and Asset Management Plan (AMP) Update & EB-2022-0200 Exhibit I.2.6-STAFF-81

	in parallel to the deployment of the IRP Pilots. Enbridge Gas has reviewed its 2023-2032 Asset Management Plan and is actively evaluating non-pilot IRP Plans. Enbridge Gas will continue to review facility projects for IRP alternatives and will engage the TWG on new technical issues. *<u>Jurisdictional scan</u>* Enbridge continues to monitor Natural Gas IRP in other jurisdictions on an ongoing basis to inform its own IRP progress. In 2022 Enbridge shared a jurisdictional review it had commissioned on ETEE / DR NG IRP programs with the TWG. Enbridge will continue to share any IRP learnings from other jurisdictions with the TWG and looks forward to further contribution from TWG members on any insights they have from other areas. Enbridge Gas notes that in moving these other areas of focus forward it has fulfilled the directives as outlined by the Board in its Decision, the status of which can be found in the 2022 Annual Report Appendix A: OEB IRP Directives. ***Scope of the IRP TWG 2023+*** Finally, comments received from IRP TWG indicate that some members view the scope of the IRP TWG as more expansive than what Enbridge Gas understands it to be from the Board's IRP Decision and from the TWG's TOR. The IRP Decision and the TWG TOR both note that the TWG's initial priority areas of focus are the Pilots and the DCF+ Test; other potential areas of focus for the Working Group may include addressing: • Learnings from natural gas IRP in other jurisdictions • Performance metrics for IRP • Accounting treatment of IRP costs • Treatment of stranded assets in system planning • Other activities relevant to the IRP Framework, as identified by the Working Group or as directed by the OEB[9] Some working group members have indicated that they interpret this list to include areas such as consultation and input into Enbridge Gas's hiring of IRP employees and the

[9] IRP Working Group - Terms of Reference (oeb.ca)

	associated staffing/organizational structure, internal strategic planning, review and input into each project within the AMP, and consultation on Enbridge Gas's broader demand forecast process; which was identified in the IRP Decision as a topic best addressed in the Rebasing proceeding[10]. Enbridge Gas, however, understands the IRP Decision and TOR to scope the IRP TWG's initial areas of focus to the Pilots and the DCF+ Test, and that other potential areas of focus would be those clearly defined items noted above, as well as processes and approaches that are new for Enbridge Gas as a result of the IRP Decision (e.g. technical evaluation, economic analysis / use of the DCF+ Test, IRP stakeholder engagement etc.) that benefit from the broad technical expertise of the TWG. It is important to note, that the topics that Enbridge Gas has highlighted as 2023 TWG priorities are aligned with most of the topics that TWG members have said that they would like to have input into. This illustrates that, contrary to some IRP TWG comments noted above, that Enbridge Gas is not opposed to, and values, the IRP TWG's expertise and insight in these areas.

[10] EB-2020-0091 Decision page 4

3. Description of Other Key Activities to Date

In accordance with the IRP decision, the Working Group's *Terms of Reference* confirmed the consideration of IRP pilot projects and guidance on the DCF+ economic evaluation methodology as the highest initial priorities for the Working Group (in addition to the review of Enbridge Gas's annual IRP report). The Working Group's efforts over the previous year focused primarily on these two items.

A high-level summary is provided below - refer to the Meeting Folders on the Engage with Us (EwU) IRP webpage[11] for meeting materials and meeting notes summarizing key discussion points and outcomes.

Consideration of IRP pilot projects to better understand how IRP can be implemented to avoid, delay or reduce facility projects.

Per the IRP Framework, 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 IRP Framework indicated that the OEB expects that the IRP pilot projects will be selected and deployed by the end of 2022.

The Working Group had several meetings to provide input to Enbridge Gas on the objective of the pilots, criteria to be used to select and prioritize pilots, and types of IRP alternatives (IRPAs) that should be of priority to test and learn from the pilots. IRPAs of notable interest to the Working Group include enhanced targeted energy efficiency (ETEE), peak shaving supply-side IRPAs including compressed or renewable natural gas (CNG or RNG) as a bridging solution, and demand response (DR) programs and/or interruptible rates focused on general service customer's heating loads and/or larger contract customers. After considering the Working Group's input, Enbridge Gas identified potential pilot areas based on specific system needs identified in its Asset Management Plan. Eight potential pilot areas were presented to the Working Group with an evaluation matrix of Enbridge Gas's ranking and weighting of criteria for each option. The Working Group provided input on the options presented by Enbridge Gas and this led to Enbridge Gas's decision to select:

[11] https://engagewithus.oeb.ca/irp

- Pilot # 1 Southern Lake Huron Pilot (a portfolio option targeting a larger area to offer a suite of IRPAs (ETEE and DR program)).
- Pilot #2 Parry Sound Pilot (a single option to address a specific need in a specific area (geotargeted ETEE and CNG as a bridging solution)).

Once Enbridge Gas determined which two pilot areas to proceed with, the Working Group had several meetings to provide input on Enbridge Gas's development of the pilot design and budget. Matters discussed included selection of specific energy efficiency measures/technologies; best practices and considerations regarding forecasting program participation and peak demand impact (including consideration of the use of derating factors, and the methodology for assessing peak demand impact developed for Enbridge Gas by Posterity Group), budgeting, and stakeholdering; mechanisms to potentially increase program uptake; collection of timely and sufficient baseline data using viable technologies; cost-effectiveness considerations including whether and how to use the DCF+ test; and tracking the effectiveness of the pilot program through monitoring, evaluation, and an audit plan. Throughout the year, members shared their experience, expertise, and research on the topics discussed during Working Group meetings and at individual member discussions when requested by Enbridge Gas. Enbridge Gas was also encouraged to reference previous pilots and IRP efforts in other jurisdictions for learnings. Members provided various examples and information sources like Con Edison, National Grid and Northwest Natural pilots they thought would be of value to Enbridge Gas.

In December 2022, Enbridge Gas filed a letter to inform the OEB that it would not be in a position to file a pilot application by the end of 2022, and anticipated filing an application in early 2023. At the time of writing, the Working Group is in the final stages of reviewing Enbridge Gas's pilot proposals, after which a pilot application is expected to be filed with the OEB by Enbridge Gas.

Enhancements or additional guidance in using the Discounted Cash Flow-plus economic evaluation methodology to assess and compare the costs and benefits of using either facility solutions or IRP alternatives to meet system needs.

Per the IRP Framework, a three-phase discounted cash flow-plus (DCF+) test was established as the economic evaluation that will be used to compare the costs and benefits of different approaches to meeting system need (IRP alternatives, facility alternatives, or a combination). The OEB concluded that the DCF+ test could be improved to better identify and define the costs and benefits of Facility Alternatives and IRP Alternatives, 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 was directed to study improvements to the DCF+ test, and encouraged to consult with the Working Group, and use the IRP pilot projects as a testing ground. Enbridge Gas was directed to file an enhanced DCF+ test for approval as part of the first non-pilot IRP Plan.

The Working Group made significant progress in providing Enbridge with suggestions to arrive at an enhanced DCF+ test, resulting in a Working Group report, *Report of the IRP Working Group on the Discounted Cash Flow-Plus Test*, finalized and made public in May 2023.

Starting July 2022, a DCF+ subgroup was formed to focus discussions on this subject matter. During the first few meetings, the agenda was set out to address some foundational issues. This included defining the purpose of each phase, aligning categories of cost and benefits with the purpose of each phase, and addressing the concept of additivity of phases in conjunction with interpreting and assigning value to the results of the different phases. The DCF+ subgroup then examined more specific issues, such as the valuation of specific categories of cost and benefits like greenhouse gas emissions, gas supply costs, risk that a constraint remains unresolved, the cost impact of other energy sources including electricity, and the treatment of non-energy benefits, including the question of monetizing such impacts versus qualitative consideration. Throughout these meetings, members shared their knowledge and expertise including a second presentation done by Working Group member and cost-effectiveness expert Chris Neme on demand related commodity price effects and risk. The subgroup also provided suggestions for improvement of a simplified DCF+ sample calculation prepared by Enbridge Gas and provided input on Guidehouse's recommendations to Enbridge Gas on matters like how to quantify and account for non-energy benefits.

Although consensus could not be reached for all items discussed during subgroup meetings, documentation of differing perspectives along with any items where consensus was reached have been captured in the Working Group's DCF+ Report. The next step will be for Enbridge Gas to develop an enhanced DCF+ Test and accompanying handbook, giving consideration to the perspectives noted in the Working Group's DCF+ Report. Enbridge Gas will then file the enhanced DCF+ test for approval with the OEB, as part of its first non-pilot IRP Plan application, as required by the IRP Decision.

Other IRP Items Discussed by the Working Group: Apart from the two pilots and enhancements to the DCF+ test, the IRP Working Group briefly discussed some additional matters in 2022 related to Enbridge Gas's overall approach to identifying system needs and considering IRP alternatives, including Enbridge's approach to developing system reinforcement plans (including the approach to customer forecasting and the degree to which hydraulic modeling is used), and the evolution of its approach to binary screening and technical evaluation of IRP alternatives for identified system needs in its Asset Management Plan. As discussed in the next section, it is expected that some of these issues will receive further consideration by the Working Group in 2023.

4. IRP Priorities and Working Group Activities in 2023

The Working Group's role on its initial priority items (DCF+ test and pre-application review of pilots) is nearly complete. In May 2023, the Working Group held a preliminary discussion of subsequent priorities for implementation of the IRP Framework in 2023, and the role the Working Group should have. Several members also made suggestions for 2023 priorities in their individual comments (chapter 2).

The Working Group gave consideration to the activities Enbridge Gas identified as priorities in its annual IRP report:

- External stakeholder outreach (including broader discussions with municipalities and municipal organizations, collaboration with IESO on best practices, regional engagement sessions, and geotargeted engagement in pilot areas)
- IRP evaluations of system needs in Asset Management Plan through technical and economic evaluation process
- DCF+ Test (submission as part of first non-pilot IRP proceeding)
- Pilot projects (regulatory review and implementation)

Of Enbridge Gas's identified 2023 priorities, the Working Group agreed that understanding, refining, and improving the evaluation process used in Enbridge Gas's IRP evaluations of system needs in its Asset Management Plan should be a high-priority item for the Working Group. Several members expressed an interest in considering the approach to demand forecasting and energy transition assumptions that is embedded in the IRP assessment process. The Working Group also agreed that the stakeholder outreach process is an important IRP priority for Enbridge Gas. Enbridge Gas is seeking advice from other organizations in developing the stakeholder outreach process, so the Working Group's role may be more limited, but there could still be opportunities for the Working Group to add value. The Working Group also generally agreed that, as Enbridge Gas works towards its identified 2023 IRP priorities, Enbridge Gas should engage the Working Group earlier in the decision-making process, rather than as a group to report out to, to make better use of the Working Group's expertise.

The Working Group also considered the other potential areas of work for the Working Group that were identified in the IRP Decision and the Working Group Terms of Reference:

- Learnings from natural gas IRP in other jurisdictions
- Performance metrics for IRP
- Accounting treatment of IRP costs
- Treatment of stranded assets in system planning
- Other activities relevant to the IRP Framework, as identified by the Working Group or as directed by the OEB

At the May 2023 Working Group discussion and in written comments, some interest was expressed in the following topics: learnings from other jurisdictions, performance metrics and incentives/penalties for IRP, expanding the list of technologies/solutions that are considered as IRP Alternatives, and how broader co-ordination of gas and electricity planning may affect IRP. There was insufficient time to discuss these additional topics in depth at the initial meeting. While there were no specific work products/deliverables identified by the Working Group or Enbridge Gas related to these additional topics at this time, this is likely to change.

OEB staff will work with Enbridge Gas to develop an updated Work Plan for the Working Group, based on 2023 priorities, to outline workstreams and expected timing of key deliverables.

Review of Enbridge Gas Inc. 2021 Integrated Resource Planning (IRP) Annual Report and Update on IRP Working Group Activities

From: Integrated Resource Planning
Technical Working Group

June 9, 2022

Contents

1. Introduction

An Integrated Resource Planning (IRP) Framework for Enbridge Gas was established by the OEB through its *July 22, 2021 Decision and Order* (the IRP Decision). The IRP Decision directed the OEB to establish an IRP Technical Working Group (Working Group) and required a report from the Working Group to the OEB (Working Group report) to be filed in the same proceeding in which Enbridge Gas's annual IRP report is filed. The IRP Decision indicated that the Working Group report should include any comments on Enbridge Gas's annual IRP report, including material concerns that remain unresolved within the Working Group, and may also describe other activities undertaken by the Working Group in the previous year.

This report has been prepared by OEB staff with input from all Working Group members, and approved by all Working Group members, as an accurate summary of the Working Group's activities.[1] Where views expressed in the report do not reflect the views of all members, this is clearly indicated.

2. Establishment and Initiation of Working Group

The IRP Decision instructed the OEB to establish a Working Group led by OEB staff, to provide input on IRP issues that will be of value to both Enbridge Gas in implementing IRP, and to the OEB in its oversight of the IRP Framework.

The IRP Decision further required the OEB to establish a terms of reference and select the membership for the Working Group. On October 19, 2021, the OEB issued a *letter* seeking nominations from individuals interested in participating on the Technical Working Group as non-utility members. The OEB selected seven non-utility members from the twenty nominations received, and announced the establishment and initial membership of the Working Group in a *letter* issued December 6, 2021. In addition to non-utility members, the Working Group includes

[1] The IRP Technical Working Group includes observers from the Independent Electricity System Operator and EPCOR Natural Gas LP. As noted in the Working Group's Terms of Reference, any materials authored by the IRP Working Group (including this report) should not be considered to represent the views of Working Group observers, or their organizations.

representatives from the OEB and Enbridge Gas, and observers from the Independent Electricity System Operator and EPCOR Natural Gas LP.

The current membership of the Working Group is shown below.

Table 1: IRP Working Group Membership

Name	Role
Michael Parkes	OEB staff representative (Working Group chair)
Stephanie Cheng	OEB staff representative
Chris Ripley	Enbridge Gas representative
Whitney Wong (replacing Amrit Kuner)	Enbridge Gas representative
Amber Crawford, Association of Municipalities of Ontario	Non-utility member
John Dikeos, ICF Consulting Canada Inc.	Non-utility member
Tamara Kuiken, DNV Inc.	Non-utility member
Cameron Leitch, EnWave Energy Corporation	Non-utility member
Chris Neme, Energy Futures Group	Non-utility member
Dwayne Quinn, DR Quinn & Associates Ltd.	Non-utility member
Jay Shepherd, Shepherd Rubenstein Professional Corporation	Non-utility member
Kenneth Poon, EPCOR Natural Gas LP	Observer
Steven Norrie, Independent Electricity System Operator	Observer

The inaugural meeting of the Working Group was held on January 18, 2022. Meetings have subsequently been held on a monthly basis, with five meetings completed as of the date of this report.

Meeting notes and meeting materials for IRP Working Group meetings are published on the OEB’s website following meetings to allow stakeholders to follow the Working Group’s progress.[2] These materials can be found at: *https://www.oeb.ca/consultations-and-projects/policy-initiatives-and-consultations/natural-gas-integrated-resource.*

As required by the IRP Decision, a draft terms of reference for the Working Group was developed by OEB staff. Following review and input from Working Group members at the initial meeting, a final terms of reference was issued by the OEB on February 17, 2022.

[2] Meeting materials are typically posted online shortly after the meeting. Meeting notes are not typically posted until after the following meeting, to allow for members to review draft notes and identify any omissions or inaccuracies.

3. Review of Enbridge Gas's Annual IRP Report and Comments on Implementation of the IRP Framework

The IRP Decision notes that the Working Group is expected to review a draft of Enbridge Gas's annual IRP report, with the review coordinated by OEB staff, and that Enbridge Gas should provide a draft of the annual IRP report to the Working Group far enough in advance of its planned filing to the OEB to allow the Working Group time to review and comment. The IRP Decision also indicates that the Working Group report should include any comments on Enbridge Gas's annual IRP report, including material concerns that remain unresolved within the Working Group.

The Working Group's review took the following steps:

Enbridge Gas

Provided a draft of its 2021 annual IRP report to the Working Group for Review

This draft included the appendix "Integrated Resource Planning Demand-Side Alternatives – Best Available Information of IRPAs".

STEP 2

Working Group Members

Provided suggested edits and comments/clarifying questions

Member comments were generally aimed at ensuring that Enbridge Gas's annual IRP report accurately describes what Enbridge Gas has done and is doing regarding IRP, and includes the information required by the IRP decision. Members also suggested opportunities to improve the usefulness of the contents of the annual IRP report.

STEP 3

Enbridge Gas

Revised and finalized its annual IRP report

Enbridge Gas provided a revised draft to the Working Group, documenting how it had taken into account comments from Working Group members, and (after a second stage of review), finalized its annual IRP report. Final determinations as to the contents of Enbridge Gas's annual IRP report were made by Enbridge Gas, not the Working Group.

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STEP 4

Working Group Members

Provided final comments on implementation of IRP Framework

Member comments are discussed further below in section 3.1

3.1. Working Group Comments on Implementation of the IRP Framework

All Working Group members (with the exception of observers) were asked the following question:

Question: Having reviewed Enbridge Gas's final annual IRP report's description of Enbridge's IRP activities in the previous year and having also participated on the IRP Working Group, do you have any comments or concerns with the implementation of the IRP Framework to date?

To varying degrees, all non-Enbridge Gas Working Group members expressed some concerns. These concerns relate primarily to: (1) the pace of Enbridge Gas's efforts to implement the IRP Framework since the IRP Decision in July 2021; and (2) the ability of the Working Group to make progress on its identified priorities (discussed in chapter 4 of this report) and meaningfully contribute to Enbridge Gas's IRP implementation, due in part to Enbridge Gas's determinations regarding the topics and level of detail that it has brought forward to the Working Group to date. More specifics are provided in the comments from individual members in Table 2, and the comments of Enbridge Gas Working Group members follow in Table 3.

Several members (including Enbridge Gas representatives) noted that more frequent meetings or focused subgroups may help advance progress on IRP implementation. The Working Group has agreed to add a second monthly meeting, with a subgroup focusing on the discounted cash flow-plus (DCF+) test, beginning in July 2022.

Table 2: Individual Comments of IRP Working Group Members

Working Group Member	Comments (optional)
Amber Crawford (non-utility member)	Since the Decision and Order was published on July 22, 2021, Enbridge Gas and OEB jointly created the nomination for membership of the IRP Technical Working Group. There have been five meetings held in 2022, and the following observations can be made thus far: **Little Progress Made on IRP Pilot Projects:** According to the Decision and Order, “the OEB expects that the [two] IRP pilot projects will be selected and deployed by the end of 2022.” (p.24). Meetings to date have discussed pilots at a very high-level, and have not yet seen substantive materials that would help the IRP Technical Working Group provide input on. While this may be in part due to Enbridge’s Asset Management Plan being developed this year, the criteria and potential choices should be further along to meet Enbridge’s deadline. **Lack of Transparency and Reliance on 2024 Rate Rebasing:** When asked to see data pertaining to pilots, the DCF+ test, binary screening results, best practices in other jurisdictions, or Enbridge’s Asset Management Plan, it has often been denied or mentioned it will be part of the 2024 Rate Rebasing in the Fall. Enbridges view that these topics are better addressed through testing of the evidence within the rebasing application. If this group is to provide input and expertise, it is incumbent on Enbridge to provide those details as otherwise, the consultation will not be meaningful. **Minimal Information in Annual IRP Report:** As a function of the slow progress in 2021, the Annual IRP Report fails to include details on key sections that would have been helpful and set up the 2022 year better (e.g. Sections 2, 6, 9). The Working Group’s review has been quite limited and question whether input to date has had a meaningful impact on Enbridge’s annual IRP report.

John Dikeos (non-utility member)	I agree with many of the comments from other Working Group members that Enbridge's progress on identifying and screening potential IRPA pilots and updating its DCF+ cost-effectiveness approach has been relatively slow. There was very limited progress on these items in advance of the first Working Group meeting in January 2022 and progress since has been slow as well. To date, this has limited the Working Group's ability to provide more meaningful contributions to the future of IRPA planning in Ontario. I noted the following additional items based on my review of Enbridge's final 2021 IRP Annual Report: **Evolution of binary screening criteria:** Enbridge has included high-level details regarding its binary screening criteria for IRPAs. Although the criteria appear to be reasonable at this stage given the current knowledge and experience with IRPAs, Enbridge should be encouraged to revisit and evolve the criteria on an ongoing basis. For example, the Timing criteria should likely be condensed as Enbridge gains additional knowledge and experience with demand-side IRPAs. **Interruptible rates:** Enbridge notes that it is completing a study on interruptible rates, which will be filed as part of its rebasing application in fall 2022. As part of this study, Enbridge should investigate alternative and/or enhanced approaches to interruptible rates, such as the pilot projects that are being run by some utilities in New York (e.g., ConEd).
Tamara Kuiken (non-utility member)	I agree with many of the comments made by other reviewers, including those related to the lack of progress made on IRP pilots, the lack of progress made on improving the DCF+ test, communication about IRP elements delayed until the rebasing application, all initial IRPAs failing the binary test, and the perfunctory IRP Report. In my opinion, Enbridge shows little urgency toward advancing the IRP process, despite their commitment to deploy pilots before the end of 2022. The initial stated reason was a desire to engage with the TWG prior to making commitments; however, the lack of progress since the TWG was initiated suggests that other barriers exist.
Cameron Leitch (non-utility member)	From the definitions within the IRP Framework, this process is meant to address system needs by considering alternatives to conventional facility projects. At the core of this process is clarity on the determination of system needs, and without

	insight into this determination (outside of the future AMP submission), it is difficult for the Working Group to provide meaningful feedback. Comments by other members of the Working Group are insightful, and my repetition of them will not provide added value to the reader.
Chris Neme (non-utility member)	While there have been some good initial discussions, and the tone of those discussions has been appropriately congenial and open-minded, I have several concerns about the effectiveness of the working group (WG) thus far. The most important are as follows: 1. **Input on key IRP issues related to the Company's next Asset Management Plan (AMP) and rate-basing application has essentially been taken off the table**. Among those key issues are (A) the Company's approach to load forecasting in light of Canada's energy transition commitment, fast-increasing carbon taxes and the potential for the Company to partially control demand growth through limitations on new connections; (B) how binary screening criteria are to be assessed/applied, including the how the timing of needs is to be determined (given the binary screening criterion that says alternatives to traditional infrastructure investments should not be considered if the system need is within three years); and (C) how risks of stranded assets are to be addressed (e.g. if load grows in the near term but then declines as electrification takes hold). Had the Company been willing to engage on these issues prior to its filing in the Fall, some progress eliminating issues – or at least surfacing key issues and ensuring that the filing provided data/info likely to be important – could have been made, saving the Board time and making the filing a better product. These kind of collaborative working groups – speaking here to a groups addressing a range of topics, not just IRP – routinely provide such construction feedback in other jurisdictions. 2. **Little progress on pilots – and therefore likely failure to begin deploy IRPAs as part of pilots before the end of 2022**. This is particularly concerning given that it is essentially one of just two issues that the WG has effectively prioritized for 2022. While I appreciate that the Company may not have wanted to get too far in planning for the pilots until the

	WG had formed, it still could have done a lot of groundwork identifying potential projects/locations for pilots (e.g. maybe developing an initial short list of 10-12) so that we could have jumped right into selection once the WG had talked through priorities. 3. **No progress on the revisions to the DCF+ cost-effectiveness test.** This also has relevance to the Company's upcoming AMP and rate-basing application, so it would have been ideal to have worked through some issues in greater detail in the first half of 2022. 4. **Enbridge's first IRP Report is largely perfunctory, with little useful information**. This seems a function of two related things: (A) no IRPAs have been identified yet for deployment; and (B) the Company has decided that all planning related to IRPA consideration will be addressed in its AMP and rate-basing application. As stated above, the Company's decision to not bring its draft approach to applying the IRP framework to its AMP is an unfortunate missed opportunity. Hopefully next year's IRP report will be more substantive. Note that greater progress on the items above may have been hindered by having just one meeting a month among a dozen or more people. That might suggest the need for some sub-groups focused on particular topics (e.g. cost-effectiveness test) and perhaps with fewer people involved to meet more often. Those subgroups could then report back draft recommendations for the full WG to consider. This model is being used very effectively, for example, by the Illinois Stakeholder Advisory Group (SAG) for energy efficiency. They have full working group meetings quarterly (used to be monthly) but have numerous subcommittees (also with regular meetings) and working groups (more episodically meeting to address specific topics that have more time-sensitive needs). See www.ilsag.info.
Dwayne Quinn (non-utility member)	As the last non-utility member to comment, instead of "piling on" regarding the lack of opportunity for the IRP WG to understand the lack of progress by the utility or even the behind the scene processes, we will simply support contributions of each of the other non-utility members. I am concerned that the Enbridge comments seem to dismiss consensus comments by the group. I believe the reality lies in the fact that Enbridge has not advanced even one single

	concrete example of a potential pilot, which could have been used to allow input from the WG on process matters. The cumulative years of experience and aggregated intellectual capital of the committee is being wasted as we await something substantive to review and to initiate collaboration.
Jay Shepherd (non-utility member)	***Very Little Has Been Done To Date.*** This Report demonstrates that little was done from July 22 to December 31, 2021 to advance IRP in Ontario. The Report discloses that the following steps were taken in that 5+ month period: 1. A bare bones website was created (perhaps a day's work), in which the primary functionality is the ability of customers to indicate their interest in regional constraints and the related IRPAs. However, there are no regional constraints or IRPAs identified, and will not be until the end of 2022 at the earliest. Enbridge promises future enhancements to the website late in 2022 or early in 2023. 2. A committee of the stakeholder engagement folks at Enbridge has been created, but they will have nothing to do until late 2022, when constraints and potential IRPAs have been identified. Nothing else appears to have been done. No preliminary work was done on the pilots, or the DCF+ test, or best practices in other jurisdictions, etc. Or, if there was, none of it was brought to the attention of the IRP Working Group. ***Asset Management Plan – Refusal to Disclose.*** In parallel, Enbridge has moved forward with its 2024-2028 Asset Management Plan, but does not appear to have incorporated IRP into that process. Further, when asked to provide information to the IRP Working Group on the process of the AMP, and how it was influenced by IRP, Enbridge refused to do so. Members of the working group sought a draft of the AMP, which should be substantially finalized at this point, but that disclosure was refused. ***Load and Demand Forecast – Refusal to Disclose.*** Related to this, Enbridge has, in 2021 and 2022, been preparing its ten year load forecast for the AMP to be filed in the rebasing application, but has declined to share any information on that forecast with the IRP working group. It does not appear that Enbridge has taken any action so far to

	influence that forecast downward through, for example, longer term planning for, or forecasting of, IRPAs. ***Posterity Group Model – Refusal to Disclose.*** Another refusal from Enbridge was the request from the IRP working group to see the Posterity Group model that Enbridge plans to use to assess IRPAs. Enbridge will not provide that model unless compelled to do so by the OEB. ***Interruptible Rates Study – No Consultation with IRPWG.*** At the same time, Enbridge has proceeded (in 2022, not 2021) with an interruptible rates study as it relates to IRP, but has not brought any information on that study to the IRP working group, and apparently does not intend to do so. ***100% Fail Rate in Binary Screening.*** To date, Enbridge has used binary screening on seven projects, and all have failed, in most cases because of Enbridge's determination that the need must be met in under three years. One of these was the St. Laurent Phase 3 and 4 project, which the OEB determined in the EB-2020-0293 LTC application would not proceed at this time. It is not known yet whether the others that failed the screening can stand up to a similar independent review. No information on that binary screening has been provided to the IRP working group. ***Pilot Projects – Non-Compliance with OEB Direction.*** Enbridge also discloses in the attached Report that they will not comply with the OEB direction to "select and deploy" two IRP pilot projects by the end of 2022. They have unilaterally determined, without input from the IRP working group, that they will complete the "select" stage by the end of the year, but will not have the pilot projects "deployed" until the winter of 2023, rather than the winter of 2022. Against this contextual background, Enbridge has been adding to rate base at an average rate of $100 million of capital additions per month since the IRP Decision, and is continuing to do so. The inescapable conclusion from this Report, and from the actions of Enbridge to date, is that their strategy is a "slow walk" of IRP, consistent with their past resistance to the concept.

Mike Parkes/Stephanie Cheng (OEB staff representatives)	In OEB staff's view, Enbridge Gas is taking the initial steps (as documented in Enbridge's annual IRP report) to implement the IRP Framework in accordance with the OEB's direction. This includes participating in good faith on the IRP Working Group. Implementation of the IRP Framework is still at a preliminary stage. At this time, OEB staff provides additional comments on three topics: • **Slow start on IRP Pilots (section 3 of Enbridge Gas annual IRP report)**: The IRP Framework indicated that Enbridge Gas should develop and implement two IRP pilot projects, with the expectation that the pilot projects would be selected and deployed by the end of 2022. Based on the description in the annual IRP report and the information that has been shared with the Working Group, the amount of preparatory work done by Enbridge Gas in the months following the IRP decision in July 2020 to lay the groundwork for these pilots (in advance of seeking input from the IRP Working Group) was very limited. While OEB staff recognizes that this was in part because Enbridge Gas did not want to overly constrain pilot design prior to receiving input from the Working Group, the result is that it is unlikely that pilots will be deployed (if "deployed" is interpreted to include having received an OEB approval) by the end of 2022, which was the expectation of the IRP Decision. The consequence is that there will be a related delay in transferring learnings from the pilots into Enbridge Gas's system planning decisions. It will be important for Enbridge Gas to make use of learnings from the pilots while they are still in-flight, to inform Enbridge Gas's consideration of IRP alternatives in system planning. • **Insufficient information base to compare IRP Alternatives Versus Facility Projects (sections 2,7, appendix B of Enbridge Gas annual IRP report)**: Under the IRP Framework, Enbridge will use a four-step IRP Assessment Process to determine the best approach to meeting system needs. Where such system needs pass an initial binary screening, Enbridge Gas is required to assess the technical and economic feasibility of IRP Alternatives in comparison with traditional facility solutions.

	The level of detail in appendix B (*Integrated Resource Planning Demand-Side Alternatives – Best Available Information*) of Enbridge's initial annual IRP report regarding IRP Alternatives, including their cost and peak demand reduction potential, is generally insufficient to assist Enbridge Gas in completing this step of IRP assessment, and will need to be improved in future annual IRP reports. Information on IRP Alternatives will be informed and improved by the results of Enbridge Gas pilots. However, Enbridge Gas will need to conduct IRP assessments prior to completion of the pilots (e.g. for potential system needs identified in Enbridge's rebasing application). In OEB staff's view, Enbridge will need to supplement the information obtained from IRP pilots with other sources of information on the expected cost and peak demand reduction potential of IRP Alternatives (including results from other jurisdictions), to assist it in completing IRP Assessments (and to assist the OEB in reviewing Enbridge Gas's determinations). Otherwise, the risk is that no IRP Alternatives will advance past this stage of IRP Assessment for many years. • **Limited information and Working Group review of IRP elements of rebasing application (sections 2, 6, 9 of Enbridge Gas annual IRP report):** The OEB's review of Enbridge Gas's rebasing application (expected to be filed in November 2021) will have significant consequences for implementing the IRP Framework. Issues of particular importance noted briefly in the annual IRP report include: Enbridge Gas's updated asset management plan and its approach (and conclusions) regarding screening system needs for IRP alternatives and reporting on the status of such consideration (section 6), Enbridge Gas's approach to demand forecasting (section 2), and Enbridge Gas's approach to studying the potential for interruptible rates (section 9). In OEB staff's view, Enbridge Gas's approach to demand forecasting in light of the energy transition to lower-carbon energy sources will likely have significant implications for IRP and system planning, both regarding identification of system needs and the role of IRP Alternatives as potential solutions.

	These issues are only mentioned briefly in the annual IRP report, and the Working Group has not to date been provided with substantive details of how these topics will be addressed in Enbridge Gas's rebasing application, and has not commented on them. At this point in time, if any review by the Working Group occurs, it will likely be quite limited. Reasons for this include: these topics were not identified as a priority for the Working Group in the IRP Framework; Enbridge Gas's view that these topics are better addressed through testing of the evidence within the rebasing application; and views of some Working Group members that input at this stage is unlikely to have a meaningful impact on Enbridge Gas's application. The consequence is that these issues will be addressed in the rebasing application without significant prior input from the Working Group.

Table 3: Comments of Enbridge Gas IRP Working Group Members

Working Group Member	Comments (optional)
Chris Ripley/Whitney Wong (Enbridge Gas representatives)	Enbridge Gas has structured its comments to follow the Working Group Participant comments above. For context, Enbridge notes that the Working Group's focus, per the Terms of Reference and the OEB's IRP Decision, are three main issues: the IRP Annual Report, the DCF+ cost/benefit test and the IRP Pilots. Enbridge Gas does not agree with the negative tone of many of the Working Group Participant comments. Enbridge Gas has been working diligently on IRP implementation and engaging responsibly with the Working Group, in a manner consistent with the OEB's directions and expectations from the IRP Framework. As described below, Enbridge Gas expects that the pace of Working Group progress and activities will increase in the coming months. **Minimal Information in Annual IRP Report:** As noted above, the 2021 IRP Annual Report is reporting on 2021 activities and information. While progress has been made on the three main Working Group tasks; Annual Report, DCF+ and pilots the work has been largely completed in 2022 and will appear in the 2022 IRP Annual Report. In addition, in Enbridge's view there is a mismatch between the IRP Annual Report, which relates to 2021, before the Working Group held its first

	meeting, and the comments from the Working Group members on that Report, almost all of which relate to the experience of the Working Group in 2022. Over the next few months, the Working Group will discuss potential pilot projects and review Enbridge Gas' proposals for the DCF+ Test. **Little Progress Made on IRP Pilot Projects:** Enbridge does not agree with the Working Group comments suggesting Enbridge Gas made little effort on the IRP Pilots Projects. The OEB's IRP Decision stated "the OEB expects that the [two] IRP pilot projects will be selected and deployed by the end of 2022." (p.24). Enbridge acknowledges deployment by the end of 2022 is not possible, this is entirely due to the timing of Enbridge's demand forecast and planning processes being completed in Q2 of 2022. The 2023-2032 Asset Management Plan ("AMP"), generated in May 2022, identifies the needs on Enbridge's system. The pilot projects need to be, and will be, based on actual system needs that have been identified in Enbridge Gas' AMP. Enbridge Gas has included an updated IRP pilot schedule in its Annual Report. Enbridge Gas will bring 4-5 actual system needs for each of the two proposed IRP Pilots to the Working Group, including all relevant information to the need. Enbridge Gas will discuss the system needs brought forward with the Working Group, select two IRP Pilot projects and then prepare an application for the OEB's review and approval. In order to complete the IRP Pilot selection process quickly, Enbridge Gas proposed to increase the number of Working Group meetings from once per month to twice per month. **DCF+ Test:** Enbridge Gas engaged Guidehouse Consulting to conduct a review of the DCF+ test approved by the OEB in the IRP Decision. Enbridge Gas expects to receive the Guidehouse Final Report in June 2022 and will use the Guidehouse report in its review of the DCF+ test and in any proposed changes. Enbridge Gas will be communicating the Guidehouse Report and Enbridge Gas' proposed changes in the July IRP Working Group meeting. As discussed at the Working Group, a sub-group will be established to review the Guidehouse Report and Enbridge's associated proposed changes to the DCF+ Test. This review and discussion will happen prior to the cost test being applied to the IRP Pilot projects or an IRPA Plan.

	Lack of Transparency and Reliance on 2024 Rate Rebasing: Enbridge Gas is filing its 2024 Rebasing Application in Fall 2022 which will include a comprehensive review of Enbridge Gas' planning processes, the demand forecast and the Asset Management Plan. Enbridge Gas never understood the Working Group would provide input on the demand forecast process and the asset management requirements. The appropriate time to review Enbridge Gas' planning processes and the Asset Management Plan is in the Rebasing proceeding, not at the IRP Working Group. Enbridge Gas is holding a Rebasing Stakeholder meeting in June 2022 where Enbridge will provide information about the upcoming filing. Enbridge Gas notes there is no direction to review or provide the planning processes, demand forecast or the Asset Management Plan to the Working Group in the OEB's IRP decision or the IRP Working Group Terms of Reference **Posterity Model:** The Working Group have requested Enbridge Gas to provide the model used by Posterity Group to assess energy efficiency opportunities on Enbridge Gas' system. Enbridge Gas does not own the Posterity model and cannot provide it. Enbridge Gas will explain the model, how it is used and the inputs/outputs as it develops the IRP Pilots. **Interruptible Rates:** In its IRP Decision, the OEB ordered 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". (p.35). Enbridge is completing this direction and it will be filed in the Rebasing Application. Enbridge Gas notes there is no direction to review the Interruptible Rates study with the Working Group in the OEB's IRP decision or the IRP Working Group Terms of Reference.

4. Description of Other Key Activities to Date

The Working Group's Terms of Reference confirmed the following items noted in the IRP Decision as the highest initial priorities for the Working Group (in addition to the review of Enbridge Gas's annual IRP report):

- **Consideration of IRP pilot projects to better understand how IRP can be implemented to avoid, delay or reduce facility projects.**

    - The IRP Framework indicated that 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 IRP Framework indicated that the OEB expects that the IRP pilot projects will be selected and deployed by the end of 2022.

    - <u>Working Group activities:</u> The Working Group has had several discussions to provide input to Enbridge Gas on pilot design, focusing primarily on the pilot objectives, the criteria that will be used to select and prioritize pilots, and the types of IRP Alternatives should be a priority to test in the pilots. Enbridge Gas has proposed four potential pilots built on different types of IRP Alternatives: (1) enhanced targeted energy efficiency in combination with a bridging supply-side solution; (2) a peak shaving supply-side IRP Alternative using either compressed natural gas or liquefied natural gas; (3) a demand response program focused on general service customers' heating loads; and (4) a demand response/interruptible rates initiative focused on Enbridge Gas's larger contract customers. Enbridge Gas is also considering a geographical IRP pilot that may address multiple needs within a specific area and include a suite of IRP alternatives, potentially including demand-side and supply-side IRP alternatives, as well as considering enhanced inspection/integrity management measures. In the coming months, it is expected that Enbridge Gas will propose specific projects that match these potential pilots to real system needs identified in its Asset Management Plan, for Working Group review, prior to Enbridge Gas's final selection of pilots. Additional discussion and refinement of the pilot proposals will take place by the Working Group, prior to Enbridge Gas filing pilot applications to the

OEB for approval.

- **Enhancements or additional guidance in using the Discounted Cash Flow-plus economic evaluation methodology to assess and compare the costs and benefits of using either facility solutions or IRP alternatives to meet system needs.**

  - The IRP Framework established a three-phase discounted cash flow-plus (DCF+) test as the economic evaluation that will be used to compare the costs and benefits of different approaches to meeting system need (IRP alternatives, facility alternatives, or a combination). The OEB concluded that the DCF+ test could be improved to better identify and define the costs and benefits of Facility Alternatives and IRP Alternatives, 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 was directed to study improvements to the DCF+ test, and encouraged to consult with the Working Group, and use the IRP pilot projects as a testing ground. Enbridge Gas was directed to file an enhanced DCF+ test for approval as part of the first non-pilot IRP Plan.

  - Working Group activities: The Working Group has had several preliminary discussions on this topic. This included an analysis and *presentation* by Working Group member and cost-effectiveness expert Chris Neme, which made several proposals to improve or refine the DCF+ test, while remaining consistent with the OEB's guidance on this topic in the IRP Decision. Enbridge Gas is also planning to propose several refinements to the DCF+ test, but these have not yet been discussed with the Working Group. In the coming months, the Working Group plans further discussion, with the goal of agreeing on a preliminary approach to cost-effectiveness that can be used for the IRP Pilot applications. Additional work will be done as needed to address issues that were not completely resolved at the time of filing the pilot applications, and may include development of a supporting guidance document regarding use of the DCF+ test.

The Working Group has also discussed whether to give any consideration to the IRP-related aspects of Enbridge Gas's rebasing application, which would likely be contingent on the degree of information that Enbridge Gas will provide regarding its application. Enbridge Gas has recently indicated that it will bring forward information on one IRP issue that will be part of rebasing - Enbridge Gas's approach to interpreting the IRP Framework's criteria for screening system needs - for discussion at an upcoming Working Group meeting, and is considering whether other IRP-related aspects of the rebasing application, including the draft Asset Management Plan, can be discussed with the Working Group.

Other potential areas of work for the Working Group in the future may include addressing:

- Learnings from natural gas IRP in other jurisdictions
- Performance metrics for IRP
- Accounting treatment of IRP costs
- Treatment of stranded assets in system planning
- Other activities relevant to the IRP Framework, as identified by the Working Group or as directed by the OEB

The Working Group has not to date discussed these topics in any depth (with the exception of some consideration of IRP in other jurisdictions with regards to pilot proposals).

A draft Work Plan is maintained for the Working Group and updated on a regular basis, outlining workstreams and expected timing of key deliverables.

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.

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

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

DECISION AND ORDER

EB-2022-0247

ENBRIDGE GAS INC.

Application for leave to construct natural gas pipelines in the City of Toronto

BEFORE: **Emad Elsayed**
Presiding Commissioner

Fred Cass
Commissioner

May 9, 2023

customer seeking expanded gas service. Environmental Defence also submitted that even if the Project can be characterized as a customer-specific build, under the IRP Framework, Enbridge Gas is required to discuss IRP options with customers who are requesting a facility option underpinned by a CIAC or long-term contract and that Enbridge Gas has provided no evidence that this kind of IRP discussion took place.[9]

In its reply submission, Enbridge Gas argued that Environmental Defence's interpretation of the intent of the Binary Screening Criteria is not correct, as the IRP Framework does not constrain applicability of the customer-specific build criterion in the manner suggested by Environmental Defence solely to projects designed to serve customers seeking incremental natural gas volumes. Enbridge Gas also submitted that there would be limited value in discussing IRP with Metrolinx as such investments would not resolve the system need underpinning the Project.[10]

Findings

The OEB finds that the Project is the best alternative to meet the stated need. Enbridge Gas evaluated several alternatives based on a number of factors such as cost, schedule, system safety and reliability, and environmental and socio-economic impacts.

The OEB also finds that the Project is excluded from IRP considerations for the following reasons:

- The Project addresses a system need that must be met in under three years.
- Because Metrolinx will pay all project costs, the project is within the intent of the findings made by the OEB in the IRP Framework decision regarding customer-specific builds where the customer fully pays for incremental infrastructure cost.

That said, the OEB expects Enbridge Gas to undertake timely in-depth quantitative and qualitative analyses of alternatives that specifically include IRP impacts in future leave to construct applications.

3.3 Project Cost and Economics

Enbridge Gas estimated the total cost of the Project to be $5.4 million, comprised of $4.6 million of pipeline facilities costs and $0.79 million in ancillary facilities costs. Enbridge Gas provided a breakdown of the Project costs for each of Phase 1 and

[9] ED submission, p.3
[10] EGI reply submission, p.11

ENBRIDGE

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Enbridge Gas Inc.
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Canada

December 22, 2022

VIA EMAIL and RESS

Nancy Marconi
Registrar
Ontario Energy Board
2300 Yonge Street, 27th Floor
Toronto, ON M4P 1E4

Dear Nancy Marconi:

Re: Enbridge Gas Inc.
Ontario Energy Board File: EB-2022-0335
Integrated Resource Planning Pilot Projects Update

Enbridge Gas Inc. ("Enbridge Gas" or the "Company") is writing this letter pursuant to the Ontario Energy Board's ("OEB") Decision and Order (dated July 22, 2021) establishing an Integrated Resource Planning ("IRP") Framework for Enbridge Gas. Specifically, within that Decision and Order the OEB stated that,[1]

> 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…

The purpose of this letter is to inform the OEB and parties of the current status of the Company's IRP pilot projects.

Based on system needs identified within its most recent 2022 Asset Management Plan, and with the input of the IRP Technical Working Group, Enbridge Gas has selected two IRP pilot projects and intends to file one or more applications with the OEB seeking approval to deploy and implement the projects in Q1 2023, in time to influence natural gas consumption for the winter of 2023/2024.

The Company is currently reviewing the selected IRP pilot projects with affected stakeholders and has commenced development of evidence to support its application(s) in 2023. Enbridge Gas intends to review its application(s) and supporting evidence with members of the IRP Technical Working Group early in 2023 in order to consider their feedback, in advance of filing with the OEB.

In order to ensure that the IRP pilot projects are deployed and implemented in 2023, in time to influence natural gas consumption, the Company has already taken limited steps to advance their implementation, including installation of necessary measurement

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[1] EB-2020-0091 OEB Decision and Order (July 22, 2021), p. 90

devices within the affected municipalities. However, Enbridge Gas will not fully implement the IRP pilot projects or seek cost recovery unless and until the OEB has granted the Company approval to do so.

Please contact the undersigned if you have any questions.

Yours truly,

Adam Stiers
Manager, Regulatory Applications – Leave to Construct

c.c. Tania Persad (Enbridge Gas Counsel)
David Stevens (Aird & Berlis)

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

DECISION AND ORDER

EB-2020-0293

ENBRIDGE GAS INC.

St. Laurent Ottawa North Replacement Project

BEFORE: Anthony Zlahtic
Presiding Commissioner

Emad Elsayed
Commissioner

May 3, 2022

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

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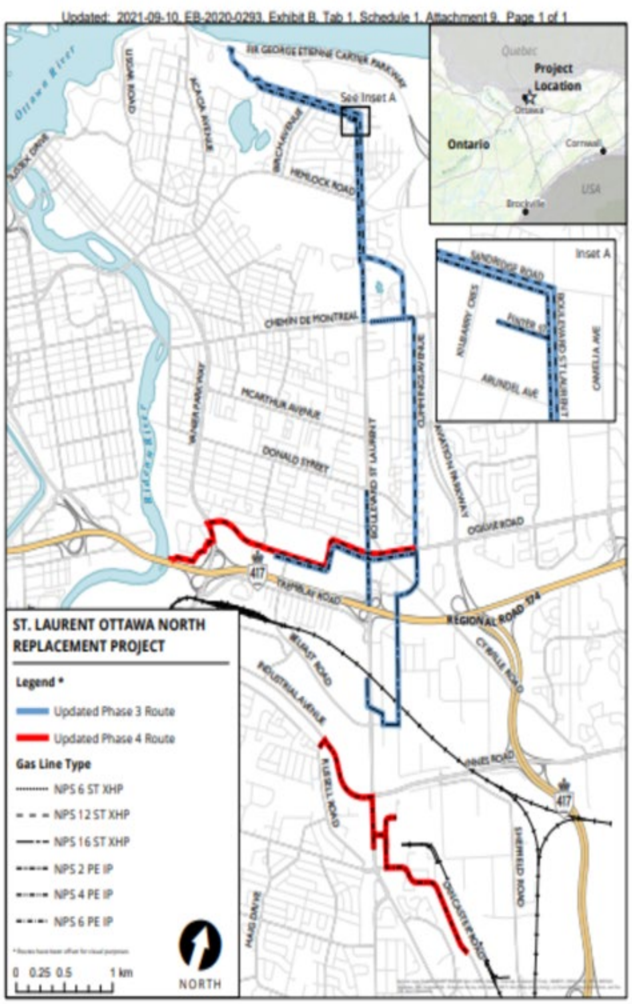
1 OVERVIEW

On March 2, 2021 Enbridge Gas Inc. (Enbridge Gas) filed an application under section 90 of the *Ontario Energy Board Act*, *1998*, S.O. 1998, c. 15, (Schedule B) (OEB Act) seeking an order granting leave to construct approximately 19.8 kilometres of natural gas pipeline and associated facilities in the City of Ottawa (Project). The application is for Phases 3 and 4 of a four-phase project to replace the St. Laurent Pipeline based on integrity issues identified by Enbridge Gas (St. Laurent Ottawa North Pipeline). Phases 1 and 2 have been completed and are in service. The general location of the Project is represented on the map below.



The proposed natural gas pipeline would replace portions of the existing St. Laurent Ottawa North Pipeline in the two final phases of the multi-year project. The OEB's determination on Phases 3 and 4 will not impact the functioning of Phases 1 and 2. Enbridge Gas has also applied under section 97 of the OEB Act for approval of the form of land-use agreements it has offered or will offer to landowners affected by the route of the Project.

Enbridge Gas's expected In Service Dates (ISD) are December 2022 and December 2023 for Phase 3 and Phase 4 respectively. Based on a request for leave to construct approval no later than February 2022, construction was planned to start in March 2022 and March 2023 for Phase 3 and Phase 4 respectively.

For the reasons provided in this Decision and Order, the OEB denies Enbridge Gas's leave to construct application. The OEB finds that the need for the Project and the alternatives to the Project have not been appropriately assessed. Enbridge Gas has not demonstrated that the pipeline integrity is compromised, and that pipeline replacement is required at this time. The OEB urges Enbridge Gas to thoroughly examine other alternatives such as the development and implementation of an in-line inspection and maintenance program using available modern technology, and propose appropriate action based on its findings as part of its next rebasing application.

2 PROCESS

The original Notice of Hearing for this application was issued by the OEB on March 19, 2021. Each of Energy Probe Research Foundation (Energy Probe), Environmental Defence Canada Inc. (Environmental Defence), Federation of Rental Housing Providers of Ontario (FRPO), Industrial Gas Users Association (IGUA), Pollution Probe and School Energy Coalition (SEC) applied and were granted intervenor status and cost eligibility.

On May 5, 2021, the OEB placed Enbridge Gas's application in abeyance to allow Enbridge Gas to adjust a segment of the proposed pipeline route. The route adjustment was required in response to issues raised by the Ministry of Transportation (Ministry). On August 11, 2021, Enbridge Gas filed a letter informing the OEB that after discussions with the Ministry and the Royal Canadian Mounted Police (RCMP), Enbridge Gas had arrived at mutually acceptable modified route to run within RCMP's property near Vanier Parkway. On September 10, 2021, Enbridge Gas filed an updated application with the OEB.

The OEB issued a Notice of Hearing of the updated application on September 30, 2021. By letter dated October 1, 2021, the City of Ottawa applied for and was granted intervenor status.

The status of the previously approved intervenors remained in effect.

The OEB issued six procedural orders. Procedural Order No. 1 set the timeline for OEB staff and intervenor interrogatories and responses by Enbridge Gas. In Procedural Order No. 2 the OEB granted a request by Enbridge Gas for an extension of the deadline for interrogatory responses to December 13, 2021. Enbridge Gas filed the interrogatory responses on December 13, 2021.

On December 17, 2021, the OEB issued Procedural Order No. 3 which set the schedule for a transcribed Technical Conference, undertakings, written submissions by intervenors and OEB staff and written reply submission by Enbridge Gas. On December 21, 2021 the OEB issued Procedural Order No. 4 approving Enbridge Gas's request to extend the final written submission deadline from February 22, 2022 to March 3, 2022.

On December 17, 2021, SEC, on its own behalf and in collaboration with the City of Ottawa and Pollution Probe (collectively, the Sponsors), requested that the OEB allow the Sponsors to submit documentary evidence (Sponsors' Evidence), and produce a witness panel, to speak to the need, cost-effectiveness, and timing of the Project. On

January 13, 2022, the OEB issued Procedural Order No. 5 approving the Sponsors' request to file the evidence and setting a new schedule for the proceeding including filing the Sponsors' Evidence; responding evidence from Enbridge Gas; a transcribed Technical Conference; undertakings from the Technical Conference; written final arguments by intervenors and OEB staff; and written final argument by Enbridge Gas. According to the procedural schedule, the record of the proceeding would be completed by April 4, 2022 with the filing of Enbridge Gas's reply argument.

The Sponsors' Evidence was presented by the City of Ottawa and the Ottawa Community Housing Corporation (OCHC). The Sponsors' Evidence covered the actions and plans of these organizations to reduce their natural gas demand within the area served by the St. Laurent system.

The Technical Conference, which was scheduled to be completed on March 4, 2022 was extended to March 7, 2022. To provide for sufficient time for the remainder of the procedural steps, the OEB issued Procedural Order No. 6 extending the procedural schedule set out in Procedural Order No. 5. Responses to undertakings from the Technical Conference were filed on March 14, 2022. Intervenors and OEB staff filed written submissions on March 24, 2022. The last procedural step was Enbridge Gas's final argument filed on April 7, 2022. That submission completed the record for the proceeding.

3 DECISION

This decision is structured consistent with the standard Issues List for natural gas leave to construct applications, to address the following issues:

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

No party, with the exception of Energy Probe, fully supported the OEB's approval of the Project. The discovery and submissions by OEB staff and intervenors were focused on issues of need for the Project and on the Project alternatives.[1] The cost and economics were discussed in the context of the comparison of alternatives, and of the consequences of stranded (under-utilized) assets for ratepayers due to potential reduction of natural gas demand resulting from decarbonization and net-zero targets and policies under development. Energy Probe supported the OEB's approval of the Project as filed and submitted that Enbridge Gas provided sufficient evidence on each of the issues in the proceeding.

Environmental Defence, FRPO, IGUA, City of Ottawa, Pollution Probe, SEC, and OEB staff all suggested that the OEB deny the application and that repair of the existing pipeline as needed, including monitoring of the declining integrity, would be a more appropriate alternative to the Project. Some these parties and the OEB staff supported retrofitting the pipeline to allow for in-line inspection to facilitate repairs on a proactive, rather than reactive, basis. Summaries of the positions of parties are included in the sections below.

[1] No major concerns were expressed with environmental impacts, landowner agreements or Indigenous consultation related to the Project.

3.1 Need for the Project

Enbridge Gas submitted that the need for the Project is underpinned by the ongoing integrity decline of vintage steel distribution mains. According to Enbridge Gas, the replacement of these portions of the St. Laurent Ottawa North Pipeline is needed to manage the risk to the safe and reliable natural gas service to approximately 165,000 customers in the City of Ottawa and Gatineau.

In its reply submission, Enbridge Gas emphasized that the need for the Project has been demonstrated and that the pipeline replacement as proposed is the best alternative to address the declining integrity of the St. Laurent Ottawa North Pipeline. Enbridge Gas asserted that the need for the replacement has been "…properly assessed through a comprehensive review with substantial documented evidence and review by pipeline integrity experts."

Enbridge Gas submitted that the need for replacement must take into account both the evidence of declining integrity and the potential consequences, should a failure occur. Enbridge Gas identified the key characteristics that give the St. Laurent system a high risk profile: i) single source supplied system; ii) extra high operating pressure; iii) supplies natural gas to approximately 165,000 customers in the City of Ottawa and Gatineau including Ottawa Health Sciences Centre, Parliament Hill, University of Ottawa; iv) feeds 10 district stations, two large control stations, and several private header stations; v) location in high consequence urban area, densely populated and transit routes; vi) pipeline failure could result in loss of service for a large number of residential and commercial customers and cause a public safety risk. Based on these critical characteristics, Enbridge Gas maintained that the St. Laurent system is a critical infrastructure and that the operational risk should be addressed by replacement.

In formulating the findings on the need for the Project, the OEB considered the following issues:

- Integrity of the Existing Pipeline
- Assessment of Risk of Declining Integrity
- Predicted Likelihood of Leaks
- Severity of Consequences of Pipeline Failure

Integrity of the Existing Pipeline

As required by Canadian Standards Association (CSA) Standard Z662 – Oil and Gas Pipeline System standards, Enbridge Gas has been monitoring the condition of its pipeline systems and associated risks and is responsible for implementing an Integrity Management Program. Enbridge Gas's Distribution Integrity Management Program

(DIMP) and Asset Health Review (AHR) determined that vintage steel distribution mains installed in the 1970s and before have demonstrated declining health. This assessment included the St. Laurent Ottawa North Pipeline which Enbridge Gas is proposing to replace through this application.

According to Enbridge Gas, the declining condition of the pipelines was determined based on the results of system surveys and inspections, conducted at various locations between 2006 and 2018. These surveys and inspections included a ground penetrating radar integrity project (2006); field work on leak repairs (2013); integrity dig (2014); bridge crossing inspection (2016); depth of cover surveys (2017); and indirect inspection to assess cathodic protection, coating, and depth of cover (2018). The results of these surveys and inspections identified corrosion, dents, compression couplings, reduced depth of cover, and past deficient cathodic protection as pipeline conditions that create a risk to the integrity of St. Laurent system. Enbridge Gas currently does not have the necessary infrastructure to conduct an in-line inspection of the St. Laurent Ottawa North Pipeline to further assess its condition.

Enbridge Gas noted that the area served by the existing St. Laurent system is a single-source natural gas network serving thousands of customers, and that the consequences of a failure, depending on the severity of the damage or defect, could be severe. In the extreme, Enbridge Gas asserted that it could be faced with the need to shut down the pipeline entirely, causing a loss of service for thousands of customers.

Assessment of Declining Integrity

An assessment of risk is determined by considering the probability or likelihood of a pipeline failure event and the severity of consequences should this event occur. Enbridge Gas provided evidence on the probability of pipeline failures and the severity of the consequences were a failure to occur.

Enbridge Gas provided a qualitative risk assessment, in the Standard Operational Risk Matrix, of service shutdown due to corrosion issues for two periods, including a winter and a summer scenario: i) 20 years average risk (2021-2041); and ii) 40 years average risk (2021-2061).[2]

[2] Enbridge Gas Inc. response to interrogatory I.STAFF.4

Table 1:
20 years Average Risk for Service Shutdown due to Corrosion Related Issues

Impact Category	Winter Scenario	Summer Scenario
Financial	Medium	Medium
Health and Safety	Medium	Medium
Customer Loss	High	Medium
Stakeholder Concerns	Medium	Medium

Table 2:
40 years Average Risk for Service Shutdown due to Corrosion Related Issues

Impact Category	Winter Scenario	Summer Scenario
Financial	Medium	Medium
Health and Safety	Medium	Medium
Customer Loss	Very High	High
Stakeholder Concerns	Medium	Medium

Enbridge Gas assessed the average risk of customer loss as "high" or "very high" in the winter scenarios for the next 20 year and the next 40 year timeframes. Customer loss is defined as the potential for emergency service shutdown to repair leaks due to corrosion related issues. This risk rating was based on the combination of severity of the consequences of leaks and the likelihood of the occurrence of leaks. Enbridge Gas stated that based on its "…Risk Evaluation criteria, risks rated at or above "High" require risk treatment." [3]

Predicted Likelihood of Leaks

Enbridge Gas used its Asset Health Index (AHI) methodology to predict how the condition of the existing St. Laurent Ottawa North Pipeline would change over a forty-year time frame (if not replaced), and to project the number of leaks that may occur. The analysis showed a decline in asset health over time, and the projected number of leaks rising over multiple decades.

Enbridge Gas provided five AHI Pipe Asset Classes based on the predicted time to first or next failure[4] and used these classes to show a graph representing a declining health of the pipeline between 2021 and 2061[5]. The predicted time of the first or next failure is greater than 40 years for the period between 2021 and 2043. The graph shows that,

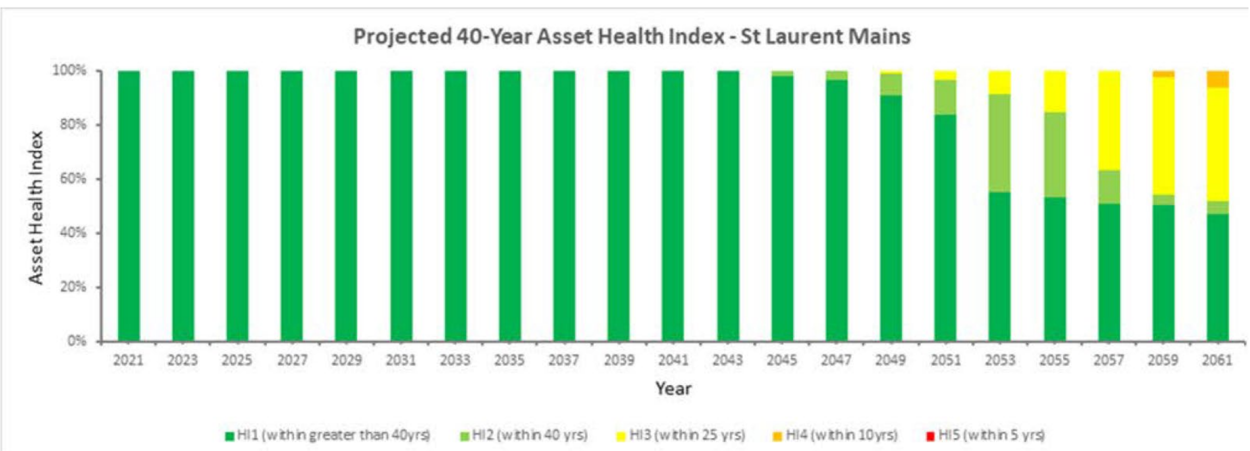
[3] Enbridge Gas Inc. response to interrogatory I.STAFF.4 c)
[4] Application, Tab 1, Schedule 1, page 41, Table 10 Asset Health Index (Pipe Asset Class)
[5] Application, Tab 1, Schedule 1, page 43, Figure 17:St. Laurent Pipeline Asset Health Index

starting in 2045, the projected time of the first or next failure become shorter and that the risk increases from 2045 to 2061.

Table 10: Asset Health Index (Pipe Asset Class)

HEALTH INDEX CATEGORY	TIME TO FIRST OR NEXT FAILURE
HI1	Greater than 40 years
HI2	Within 40 years
HI3	Within 25 years
HI4	Within 10 years
HI5	Within 5 years

Figure 17: St. Laurent Pipeline Asset Health Index



Regarding the prediction of the number of leaks, Enbridge Gas AHI model predicts 4.3 cumulative leaks by 2041. By 2051, it predicts 13 cumulative leaks, and by 2061, 36.8 cumulative leaks. Enbridge Gas's evidence showed that, by 2041, only an estimated 1% of these leaks (0.043 cumulative leaks) would potentially require pipeline isolation leading to customer disconnection. This is shown in table below. [6]

[6] Application, Exhibit B, Tab 1, Schedule 1, Table 11: Asset Health Index and Projected Cumulative Leaks, page 42

Table 11: Asset Health Index and Projected Cumulative Leaks

2041

Asset Health Index	Length (m)	Asset Count	Projected Leaks
HI1 (within greater than 40yrs)	13418.3	167	
Grand Total	**13418.3**	**167**	**4.3**

2051

Asset Health Index	Length (m)	Asset Count	Projected Leaks
HI1 (within greater than 40yrs)	8552.2	140	
HI2 (within 40 yrs)	3592.7	22	
HI3 (within 25 yrs)	1273.4	5	
Grand Total	**13418.3**	**167**	**13.0**

2061

Asset Health Index	Length (m)	Asset Count	Projected Leaks
HI1 (within greater than 40yrs)	4714.1	79	
HI2 (within 40 yrs)	112.8	8	
HI3 (within 25 yrs)	7258.9	70	
HI4 (within 10yrs)	1332.5	10	
Grand Total	**13418.3**	**167**	**36.8**

As for past occurrences, Enbridge Gas indicated that it had one corrosion-related leak in the St. Laurent system in the past 10 years. This leak was repaired by way of a cut-out of an 8 metre segment of the pipeline at a cost of $151,550.47. Enbridge Gas also indicated that in the past 10 years, there had been other repairs to the pipelines in the St. Laurent system due to corrosion that did not result in a leak (loss of containment).[7]

Enbridge Gas estimated that roughly 1% of the system leaks predicted by its AHI model could trigger a scenario where it would have no option but to isolate the pipeline and disconnect customers. Enbridge Gas noted that this was an order-of-magnitude estimate only, and the approach to repair a leak would be entirely dependent on the specific circumstances of any given leak.[8]

Enbridge Gas confirmed that it has not experienced any catastrophic failures (complete ruptures of the pipeline) on any pipelines similar in nature to the St. Laurent pipeline system.[9]

[7] Enbridge Gas Inc. response to interrogatory I.FRPO.14
[8] Tech Conference Day 1, pp. 209-212. Exhibit JT 1.26
[9] Exhibit JT 1.9

Enbridge Gas also indicated that the complete shutdown to repair a leak is assessed as a “rare event”, not a high probability event.

Severity of Consequences of Pipeline Failure

Enbridge Gas modelled two scenarios describing the consequences of pipeline failure which would trigger a complete service shutdown and an emergency response. The first scenario models the consequences of a service shutdown at 47 Degree Day (corresponding temperature of -29C). The second scenario presents the consequences of a shutdown at 1 Degree Day (corresponding temperature of 17C). The tables below from the Enbridge Gas evidence include projections of customer losses by customer type under the two scenarios.[10]

Table 1: Customer Loss at 47 Degree Days by Customer Type

Customer Type	Number of Customers Lost: Enbridge Gas	Number of Customers Lost: Gazifère	Total Customers Lost
Residential	28,226	28,285	56,511
Apartment*	35	248	283
Commercial*	3,345	2,037	5,382
Industrial	17	7	24
Total	**31,623**	**30,577**	**62,200**

*Commercial customers include some apartment customers due to building use.

Table 2: Customer Loss at 1 Degree Day by Customer Type

Customer Type	Number of Customers Lost: Enbridge Gas	Number of Customers Lost: Gazifère	Total Customers Lost
Residential	15,342	0	15,342
Apartment*	31	0	31
Commercial*	1,292	0	1,292
Industrial	11	0	11
Total	**16,676**	**0**	**16,676**

*Commercial customers include some apartment customers due to building use.

Under the 47 Degree Day scenario, customer loss would be 62,200 customers in Enbridge Gas’s and Gazifere’s franchise areas. Under the 1 Degree Day scenario, customer loss would be 16,676 customers in Enbridge Gas’s franchise area and no loss in Gazifere’s franchise area.

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[10] Exhibit B, Tab 1, Schedule 1, pages 7-13, paragraphs 13-22: Consequences of Failure; page 10, Table 1: Customer Loss at 47 Degree Days by Customer Type; and page 12, Table 2: Customer Loss at 1 Degree Day by Customer Type

The estimated cost associated with such an event in the Enbridge Gas franchise area in the 47 Degree Day scenario is $54M (Enbridge Gas estimated the cost of repair in the Gazifere franchise area to be $37M). Under the 1 Degree Day scenario, Enbridge Gas estimated the cost of an event to be $22M in its franchise area. Most of the cost estimates provided by Enbridge Gas for the two scenarios would be attributable to projected customer claims due to loss of service.[11]

Positions of Parties

The City of Ottawa submitted that the evidence on the integrity of the existing pipeline is contradictory. The City of Ottawa recommended that "…provided that integrity issues are not an immediate significant concern" the OEB should consider not approving the Project. The City of Ottawa noted that its Energy Evolution Plan, which would contribute to lowering demand for natural gas, should be considered and that not approving the Project would have benefits such as reducing the impact on local businesses, allowing the transition to a lower natural gas demand, continuing to monitor the integrity of the St. Laurent Ottawa North Pipeline, and allowing for natural gas infrastructure planning integrated with the Energy Evolution Plan.

FRPO's view was that Enbridge Gas's evidence was lacking sufficient technical information (i.e. disclosure of the potential for robotic inspection) to demonstrate that the pipeline is in poor condition and that the replacement is urgently needed. FRPO stated that risk and consequences of failure and outage to the customers were exaggerated. FRPO urged the OEB to deny the application and "…order EGI to perform enhanced in-line inspection and maintenance and report findings as part of its rebasing application".[12]

IGUA submitted that the OEB should carefully consider whether Enbridge Gas has established that the integrity of the existing pipeline is "compromised and full replacement is required at this time".[13] IGUA highlighted the inelasticity of natural gas demand of large industrial customers (compared to residential and commercial), and barriers to their conversion from natural gas indicating that increasing access to natural gas may be part of decarbonization transition for the industrial customers. IGUA is concerned with "…exposure to stranded 'small pipe' assets" such as the potentially under-utilized St. Laurent Ottawa North Pipeline should the trends of reduced demand continue as part of wider decarbonization programs. IGUA noted a risk of higher natural

[11] Enbridge Gas Inc. in response to I.FRPO.25
[12] FRPO Written Submission, March 21, 2022, page 1
[13] IGUA Written Submission, March 24,2022

gas costs to its members who are, in IGUA's words, captive customers, because of the inelasticity of their demand for industrial processes and manufacturing.

Pollution Probe recommended that the OEB reject the Project, stating that the need for a replacement has not been supported by Enbridge Gas's evidence on declining integrity and safety risks.

SEC submitted that the OEB should deny the approval of the Project. SEC's position was that the need for replacement at this time was not supported by Enbridge Gas's evidence.

OEB Staff was not convinced that an immediate pipeline replacement was required. OEB staff noted that, based solely on the predicted likelihood of leaks, the urgency to address the integrity decline concerns did not appear high.

Findings

The OEB finds that Enbridge Gas has not demonstrated that the risk associated with the subject pipelines warrants complete replacement at this time. The issue of associated risk is addressed in this section. The issue of Project alternatives is addressed in the next section.

The risk of a catastrophic failure of the subject pipelines is a function of the probability of failure and the consequences of such failure. While Enbridge Gas may have demonstrated that a catastrophic failure of the pipelines could have severe consequences for its customers by virtue of their location in a densely populated urban area, the OEB finds that Enbridge Gas has not demonstrated that the likelihood of such failure warrants a replacement of these pipelines at this time.

This finding is based on Enbridge Gas's probabilistic analysis which predicted a small number of future leaks over the next 20 to 30 years and a very low likelihood of those leaks requiring pipeline isolation leading to customer disconnection. Enbridge Gas's predicted AHI shows that the subject pipelines would remain in the top (best health) category for at least 20 more years.

In its reply argument, Enbridge Gas downplayed the significance of its AHI statistical analysis stating that "the AHI analysis (and the resulting corrosion-related leak forecast) is derived not from known issues related to the St. Laurent Pipeline, but it is instead derived from a statistical analysis of a number of pipelines across Enbridge Gas's service territory and based upon a specific set of generalizing assumptions."[14] Enbridge Gas introduced and relied on the AHI analysis during the proceeding and did

[14] Enbridge Gas Reply Submission, page 21, para 41.

not describe these limitations in the original application. Given that Enbridge Gas only emphasized these limitations in its reply argument, the parties in this proceeding did not have an opportunity to challenge Enbridge Gas's claims about the AHI limitations and the weight that should be placed on the AHI results. The OEB also notes that the low actual historical incidence of corrosion-related leaks specific to the St. Laurent system (one such leak in the last 10 years) does not demonstrate that pipeline replacement is warranted at this time.

Enbridge Gas did indicate that the AHI information should be considered along with other information obtained from integrity digs and repairs on the St. Laurent Pipeline. Enbridge Gas stated that these other sources of information were excluded from the AHI as they could not be reliably translated into meaningful qualifiers at the time of assessments.

Enbridge Gas also indicated that the risk can be mitigated by increased leak survey frequency and regular monitoring of the pipelines.

The OEB suggests that Enbridge Gas take a proactive approach to inspecting and maintaining the subject pipeline until it can be demonstrated that pipeline replacement is necessary. This may include development and implementation of an in-line inspection and maintenance program using available modern technology as discussed in the next section. The evidence in this proceeding revealed that Enbridge Gas does not currently have the necessary infrastructure to carry out such in-line inspections in the St. Laurent Pipeline.

3.2 Alternatives to the Project

Enbridge Gas presented comparative assessments of alternatives to the Project including:

- Options to manage integrity decline risk: Retrofit Option and Repair Option
- Integrated Resource Planning Alternatives (IRPAs)
- Downsizing the pipeline in response to potential natural gas demand reduction in the future

Enbridge Gas did not accept the Retrofit Option or Repair Option as preferred alternatives to the Project because, in Enbridge Gas's view, these alternative options do not resolve the integrity issues and cause additional costs (the potential cost of ongoing repairs, and, for the Retrofit Option, the upfront cost of retrofit). Enbridge Gas maintained that the proposed Project is the best alternative to meet the need to manage the declining integrity risks and ensure continuous safe and reliable service.

Enbridge Gas rejected IRPA as a viable alternative, as in its view, it does not address the integrity issue which is the underpinning need for the Project. Enbridge Gas also rejected the alternative of downsizing the pipeline in combination with demand reduction by IRPA or other programs and initiatives, on the basis that demand reduction sufficient to downsize the pipeline was not feasible within the short timeframe that the integrity concerns need to be addressed.

In reaching its conclusion regarding the evaluation of alternatives to the Project, the OEB considered the following options and issues:

- Retrofit Option
- Repair Option
- Sponsors' Evidence and City of Ottawa's Energy Evolution Plan
- Integrated Resource Planning Alternatives
- Downsizing the Pipeline due to Reduced Future Demand for Natural Gas

Retrofit Option

As an alternative to the Project, Enbridge Gas considered retrofitting the St. Laurent Ottawa North Pipeline to allow for in-line inspection. This would enable a more comprehensive assessment of the condition of the pipeline and potentially allow for a more proactive (rather than reactive) repair program. Enbridge Gas determined that the cost of retrofits and in-line filters needed to accommodate in-line inspection would be approximately $30.2 M.

Enbridge Gas rejected this alternative, noting that the retrofit would not resolve the integrity issues, with customers being exposed to the possibility of ongoing repair costs (in addition to the high capital cost of the retrofit), which could potentially culminate in a full pipeline replacement if the systemic nature of the integrity concerns was confirmed.[15] However, Enbridge Gas also noted that the retrofit could theoretically enable the pipeline to be inspected and repaired indefinitely.[16] In its reply submission, Enbridge Gas submitted that a retrofit would not guarantee that all future repairs would be solely proactive.[17]

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[15] Enbridge Gas Inc. response to interrogatory I.Staff.5
[16] Enbridge Gas inc. response to interrogatory I.Staff.5
[17] Enbridge Gas Reply Submission, page 40.

Repair Option

The Repair Option involves Enbridge Gas reactively responding to identified leaks or concerns using Enbridge Gas's existing practices.[18]

Enbridge Gas compared the Repair Option to the proposed Project assuming the probability of pipeline failure over 40 years and beyond. Enbridge Gas used the AHI for this comparative assessment.

Enbridge Gas estimated the direct capital cost of the Repair Option to be $33.0 M compared to Project total costs of $73.5 M.[19] The table below indicates lower total cost and Net Present Value of the Repair Option vs. Project (i.e. Replace Option).[20] The costs in the table exclude contingency costs and costs associated with the intermediate pressure polyethylene portions of the Project. Including these costs brings the Project cost (Replace Option) to $123.7 M.

Table 13: Comparison of Repair Option & Replace Option (Project) Costs

($ millions)	Repair Option	Replace Option
Total Cost	$33.0	$73.5
Net Present Value	$(7.7)	$(58.9)

Enbridge Gas rejected the Repair Option, stating that continuing to manage the pipeline in a reactive manner exposes ratepayers and the general public to an unacceptable level of risk to reliable service and safety.

Enbridge Gas also provided an updated cost comparison of the Replace Option and Repair Option in the table below adding the in-line inspection costs which actually would be a Retrofit Option [21].

[18] See Exhibit I.ED.10c for a description of these practices
[19] Enbridge Gas Inc. response to interrogatory I.ED.17
[20] Exhibit B, Tab 1, Schedule 1, page 47
[21] Transcript Technical Conference, March 4, 2022, page 99 line 20 to page 100 line 27 and JT1.16

Table 13: Comparison of Repair Option and Replace Option (Project) Costs Including Abandonment

($ millions)	Repair Option	Replace Option
Total Cost	$63.8	$111.5
Net Present Value	($33.9)	($91.2)

Note:

Replace Option includes both the abandonment costs and the IP PE costs, etc.

The NPV impact for the abandonment cost is approx. ($6.9) million.

Total abandonment cost is approx. 10.3 million.

The comparison in the table above includes additional cost of abandonment and cost of intermediate pressure polyethylene pipelines in the Replace Option and costs of retrofit and in-line inspection costs in the Repair Option. The updated information shows that the Retrofit Option (in-line inspection plus repairs) is $57 M less expensive than the Project.

Sponsors' Evidence and City of Ottawa's Evolution Plan

The Sponsors' Evidence provided details on the City of Ottawa's Energy Evolution Plan, approved by City Council in October 2020, and the programs and plans initiated in support of this plan.

The Energy Evolution Plan aims to reduce the corporate City of Ottawa emissions to zero by 2040 and community-wide emissions from all entities within the City of Ottawa to zero by 2050. The City of Ottawa indicated that by 2050, renewable natural gas is expected to provide approximately 12% of the community's energy requirements, versus the 50% of the community's energy needs that is currently provided by conventional natural gas. The City of Ottawa indicated that it had not yet determined whether or for how long the existing natural gas distribution infrastructure would be needed to distribute renewable natural gas.[22] The corporate City of Ottawa accounts for only about 3-4% of the overall natural gas consumption by the community.[23]

Broadly speaking, this planned reduction in natural gas use (for both corporate City of Ottawa buildings and buildings in the community) would be achieved through a combination of fuel switching from natural gas to electric heat pumps and building retrofits to significantly reduce building energy demand. The City of Ottawa and OCHC both provided details on the initial projects they have undertaken or were in the process of undertaking under this emissions reduction strategy.

The Sponsors' Evidence also stated that the federal government's Energy Services Acquisition Program would materially reduce natural gas use in the St. Laurent Ottawa North Pipeline area, due to conversion of the Cliff Street heating and cooling plant from steam to hot water, with a projected greenhouse gas emissions reduction of 87% by 2025, with almost all of this reduction coming from reductions in natural gas use.[24] However, the City of Ottawa was unable to provide specific details from the federal government on the estimated reduction in natural gas demand from the Cliff Street plant.[25]

[22] Response to interrogatories on Sponsors' Evidence, 2.1-Staff-4
[23] Response to interrogatories on Sponsors' Evidence, EGI.2(b)
[24] Sponsors Evidence, page 4
[25] Response to Undertaking JT 2.8.

Integrated Resource Planning Alternatives

Enbridge Gas submitted that a detailed assessment of IRP alternatives was not required, because the Project is driven by integrity concerns that must be addressed within 3 years, and thus fails the "Timing" screening criterion in the IRP Framework.[26]

Enbridge Gas based its assessment against the Binary Screening Criteria set by the OEB in its Decision and Order on Enbridge Gas's Integrated Resource Planning Proposal issued on July 22, 2021 (IRP Decision)[27]. Enbridge Gas noted that it determined that "… the Project is driven by integrity concerns that must be addressed within three years and no demand or supply side solution can resolve integrity concerns". To support its decision not to include IRPAs in the assessment of alternatives to the Project, Enbridge Gas referred to the following excerpt from the IRP Decision:

> 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.

Prior to the issuance of the IRP Framework, Enbridge Gas had already engaged a consultant to undertake a preliminary examination of the potential for Demand Side Management (DSM) to provide reductions in peak demand, as discussed in the next section. However, once the IRP Framework was in place, Enbridge Gas determined that it was not appropriate or necessary to conduct further IRP assessment due to the timing screening criterion.[28]

Downsizing due to Demand Reductions or IRP Alternatives

Enbridge Gas sized the proposed Project based on the peak design day demand that would need to be met based on its current customers and firm contractual customer commitments, using its existing demand forecasting methodology.[29] Enbridge Gas did not seek to add pipeline capacity for growth, relative to the existing pipeline.

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[26] IRP Framework, section 5.2
[27] EB-2020-0091
[28] Application Exhibit B, Tab 1, Schedule 1, pages 12-13, paragraph 23
[29] Enbridge Gas Inc. response to interrogatory I.ED.6

Enbridge Gas retained a third-party consultant (Posterity Group) to evaluate the potential for targeted DSM or enhanced targeted energy efficiency to provide reductions in peak demand that might reduce the size of the Project, based on estimates of the achievable DSM potential in the 2019 Achievable Potential Study.[30] This analysis concluded that there was not enough DSM potential to reduce the size of the pipeline.[31]

Enbridge Gas indicated that it had not specifically taken into account the programs and plans described in the Sponsors' Evidence in its demand forecast, as these programs were aspirational in nature.[32] In responding evidence, Enbridge Gas estimated the potential peak demand reductions that could be achieved by City of Ottawa sites, OCHC sites, and the Cliff Street heating and cooling plant served by the St. Laurent Ottawa North Pipeline. Enbridge Gas concluded that, even if all of these sites reduced their peak natural gas demand to zero, the overall peak demand reduction would only be about 1/3 of that needed to downsize the proposed Project by one pipeline size.[33] Approximately 75% of the potential peak day demand reductions attributable to these sites is from the Cliff Street plant. Enbridge Gas indicated that despite the plans to reduce emissions and natural gas use at the Cliff Street plant, its understanding was that the facility would retain its current contract demand for natural gas.[34]

Positions of the Parties

The City of Ottawa did not propose a specific alternative to the Project. However, the City of Ottawa indicated that "approving another natural gas pipeline to supply the City of Ottawa for the next 40-100 years is in direct conflict with Energy Evolution in the City of Ottawa."[35] City staff indicated that its preference would be for an integrated energy planning approach that would require the main energy suppliers (gas, electricity and district energy) to work together to build an energy system which meets the Energy, Evolution climate goals while ensuring affordability and energy security.[36]

Environmental Defence requested that the OEB direct Enbridge Gas to implement the Repair Option stating that it is a safe option which also avoids the risk of under-

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[30] Enbridge Gas Inc. response I.Staff.6(d), including attachment
[31] The Posterity memo indicates that a reduction of 63,900 m^3/hr in peak hour demand would be needed to reduce the pipeline size, while the maximum potential peak demand reduction from DSM was only 10,100 m^3/hr. {Elsewhere, in Exhibit I.ED.13 and responding evidence, Enbridge Gas indicates that only a 32,500 m^3/hr peak demand reduction would be needed for downsizing.}
[32] Interrogatory responses to Enbridge Gas's Evidence, Exhibit I.Ottawa,3
[33] Enbridge Gas Responding Evidence, pages 3-5 of 7
[34] Interrogatory response to Enbridge Gas's Evidence, Exhibit I.EP.2; Technical Conference Transcript, March 4, 2022 Day 1, page 209. Technical Conference Transcript, March 5, 2022 Day 2, pages 68-69
[35] Letter to the OEB, City of Ottawa, October 1, 2021
[36] Response to interrogatories on Sponsors' Evidence, 2.1-Staff-4

utilization of the Project's infrastructure. Environmental Defence observed that decarbonization plans by the City of Ottawa and federal 2050 fossil fuels net-zero target legislation [37] exposes the pipeline to becoming a stranded under-utilized asset at the risk of ratepayers.

IGUA recommended that the OEB carefully considers Enbridge Gas's evidence on the need for and alternatives to the Project and suggested that the OEB consider the monitor and repair alternative instead of approving the replacement as proposed in the Project.

Pollution Probe pointed to the higher cost of the Project as compared to the alternatives and noted the likelihood of stranded assets suggested that it would be more beneficial to extend the life of already depreciated existing pipeline assets. Pollution Probe observed that Enbridge Gas did not provide risk assessment of the Project becoming under-utilized over the next decades. Pollution Probe recommended "the more prudent and economic alternative of monitoring and maintaining the existing pipeline".

SEC summarized its submission by stating that there is no urgent need for the pipeline replacement, as major customers will be reducing reliance on fossil-based gas which is consistent with government policies and commitments by Canada and internationally.

In terms of the alternatives to the replacement, SEC proposed that Enbridge Gas should implement the Repair Option and report to the OEB at the time of its rebasing application.[38] SEC argued that a Repair Option has lower and known costs, avoids stranded asset risk and allows time for imminent potential reduction in natural gas demand due to the implementation of decarbonization and net-zero plans. SEC also noted that the Repair Option carries lower regulatory risk compared to the Project (Replacement Option). SEC offered views on future replacement saying that if Enbridge Gas applies in the future for St. Laurent Ottawa North Pipeline replacement, it must include in the evidence a forecast of average and peak demand for the full useful life of the pipeline and consider gas use reduction plans of its customers and complete assessment of all alternatives including IRP alternatives.

OEB staff recognized the need for integrity risk management but was not convinced that the Project would be the best alternative to address the need. OEB Staff suggested that the (reactive) repair option might not be appropriate because of increasing reliability risk of the declining integrity of the existing pipeline. OEB staff submitted that the Retrofit Option could be more appropriate than the pursuit of the Project. In OEB staff's view the

[37] Canadian Net-Zero Emissions Accountability Act, S.C. 2021, c.22
[38] SEC Final Argument, March 24,2022, page 7, paragraph 1.3.8

Retrofit Option would allow the pipeline life to be extended by several decades, and the retrofit would also likely be more economical than a full replacement at this time, due to, among other things, the time value of delaying the high capital cost of the replacement. OEB staff noted that this would also provide flexibility for a possible pipeline size reduction if a replacement would be required should demand reductions associated with Energy Evolution or through IRPA initiated by Enbridge Gas be realized. OEB staff suggested that a Retrofit Option may be the most appropriate alternative to address the declining conditions of the St. Laurent Ottawa North Pipeline.

OEB staff submitted that the IRP alternatives pursued by Enbridge Gas, including targeted DSM, in the near term would not feasibly reduce the peak demand served by the St. Laurent system on a scale sufficient to reduce the sizing of the proposed Project.

OEB staff supported the energy planning approach described by the City of Ottawa, and closer collaboration between Enbridge Gas and the City of Ottawa to proactively plan a course of action.

Findings

The OEB finds that Enbridge Gas has not provided sufficient evidence to demonstrate that the proposed Project (pipeline replacement) is the best available alternative. As an example, Enbridge Gas's comparison of the total cost and Net Present Value of the Project (pipeline replacement) versus the pipeline Retrofit Option which would allow for ongoing in-line inspection and repair, showed that the Retrofit Option is a less costly alternative even though Enbridge Gas presented a number of qualitative factors to demonstrate that the replacement option is preferrable.

Several parties argued the Retrofit Option, in addition to having a lower initial capital cost, would also have the potential advantage of providing flexibility for a possible pipeline size reduction should demand reductions be realized. In its reply argument, Enbridge Gas only provided a qualitative description of some of the disadvantages of the Retrofit Option.

The OEB urges Enbridge Gas to thoroughly examine other alternatives such as the development and implementation of an in-line inspection and maintenance program using available modern technology, and propose appropriate action based on its findings, as part of its next rebasing application.

The OEB suggests that Enbridge Gas should work collaboratively with the City of Ottawa and other stakeholders to proactively plan a course of action if and when pipeline replacement is required, including the pursuit of Integrated Resource Planning (IRP) alternatives. Enbridge Gas has not carried out a detailed assessment of the IRP alternative citing that the pipeline integrity concerns must be addressed in less than three years which is the OEB threshold for carrying out an IRP assessment. As discussed earlier, Enbridge Gas has not provided strong evidence to support the claim that the integrity threat to the pipelines is imminent and that replacement in less than three years is necessary.

In more general terms and to the extent applicable for future leave to construct applications, the OEB encourages Enbridge Gas to undertake in-depth quantitative and qualitative analyses of alternatives that specifically include the impacts of IRP, DSM programs and de-carbonization efforts.

3.3 Project Cost and Economics

Enbridge Gas estimated the Project costs as shown in the table below to be approximately $33.9 M for the IP PE pipeline segments and $89.8 M for XHP ST pipelines, totalling approximately $123.7 M.

The abandonment costs are not included in the cost estimates for the Project.

Table 9: Estimated Project Costs

Item No.	Description	IP PE Costs	XHP ST Costs	Total Costs
1.0	Material Costs	$358,484	$1,268,313	$1,626,797
2.0	Labour Costs	$20,369,317	$48,953,572	$69,422,889
3.0	External Permitting & Land	$6,303	787,387	$793,690
4.0	Outside Services	$2,849,096	$4,523,814	$7,372,910
5.0	Direct Overheads	$531,062	$751,515	$1,282,577
6.0	Contingency Costs	$3,318,390	$16,405,401	$19,723,791
7.0	**Project Cost**	**$27,432,652**	**$72,690,002**	**$100,122,654**
8.0	Indirect Overheads	$6,203,171	$16,340,923	$22,544,094
9.0	Interest During Construction	$230,655	$782,119	$1,012,774
10.0	**Total Project Costs****	**$33,866,478**	**$89,813,044**	**$123,679,522**

*XHP ST costs are a Class 5 cost estimate
**Abandonment costs are not included in the cost estimates. Abandonment costs for IP PE are estimated to be $2,817,235 and XHP ST abandonment costs are estimated to be $7,518,548

Enbridge Gas provided the costs of comparable projects completed in the past and approved by the OEB including the cost of the completed Phase 1 and Phase 2 of the St. Laurent Replacement Project. The table below summarizes this information.[39]

Case #	Project Name	City	Year	Pipe Size (Diameter / Material)	Length (km)	Estimated Total Costs (millions)	Estimated $/meter*	Assumed Contingency	Actual Total Costs (millions)	Actual $/meter
EB-2015-0042	Sudbury NPS 10 Replacement Project	Sudbury	2015	NPS 12 Steel	0.7	$2.023	$2,890	10%	$1.023	$1,461
EB-2016-0122	2016 Sudbury Replacement Project	Sudbury	2016	NPS 12 Steel	0.85	$2.188	$2,574	13%	$3.360	$3,953
EB-2016-0222	Sudbury Maley Replacement Project	Sudbury	2016-2017	NPS 12 Steel	2.8	$6.304	$2,251	12%	$4.206	$1,502
EB-2017-0180 (1)	2018 Sudbury Replacement Project	Sudbury	2018	NPS 12 Steel	20	$74.000	$3,700	15%	$82.616	$4,131
EB-2019-0006 (2)	St Laurent Pipeline Project Phases 1/2	Ottawa	2018-2020	NPS 2, NPS 4, NPS 6, & NPS 8 PE	5.1	N/A	N/A	25%	$10.545	$2,077
EB-2019-0172 (3)	Windsor Line Replacement Project	South-western Ontario	2020	NPS 6 Steel	64	$92.744	$1,449	15%	TBD	TBD
EB-2020-0192 (4)	London Lines Replacement Project	South-western Ontario	2021	NPS 4 & NPS 6 Steel	90.5	$133.909	$1,480	14%	TBD	TBD
EB-2020-0293	St Laurent Ottawa North Replacement Project Phases 3/4	Ottawa	2022-2023	NPS 2, NPS 4, & NPS 6 PE NPS 6, NPS 12, & NPS 16 Steel	19.8	$100.123	$5,053	15% for PE 30% for Steel	TBD	TBD

*Variations in cost per metre are significantly influenced by specific project scope parameters.

Notes

(1) EB-2017-0180: The 2018 Sudbury Replacement Project had large proportions of rock excavation, wetland management, a specialized Cathodic Protection design and bypass installations, which are all costly activities that are not present to the same extent or not present at all in the previously approved OEB projects as indicated in the table. It is the influence of this construction scope that has increased the cost per metre for the 2018 Sudbury Replacement Project. Estimated Total Costs for this project were later increased to $83 million.

(2) EB-2019-0006: The actual costs listed are for all components of St. Laurent Phase 1/2. The estimated costs are listed as N/A because portions of Phase 1/2 were not included in the LTC submission EB-2019-0006. The estimated costs included in LTC submission EB-2019-0006 were $5.511 million for the installation of 1.7 km of NPS 6 PE IP main, resulting in a cost/meter of $3241/m.

(3) EB-2019-0172: For comparison purposes, Estimated Total Costs as indicated in the table for the Windsor Line Replacement Project represents "Estimated Incremental Project Capital Costs" (excludes Indirect Overheads of $14.061 million).

(4) EB-2020-0192: For comparison purposes, Estimated Total Costs as indicated in the table for the London Line Replacement Project represents "Estimated Incremental Project Capital Costs" (includes Stations, Services, Abandonment and IDC; excludes Indirect Overheads of $30.189 million).

Enbridge Gas stated that the contingency levels of 15% for polyethylene and 30% steel segments of the Project apply to all direct capital costs. The contingency levels are, according to Enbridge Gas, determined at the time of filing the application "…to correspond to the project/design maturity at the time of filing…". Enbridge Gas indicated that it would reduce contingency cost as the Project's risks are identified and mitigated and design is finalized [40]

The contingency levels for the projects included in the above comparison table are 15% and below except for the St. Laurent Project Phases 1 and 2 where it was 25%. The estimated cost for the Project is the highest in comparison to the costs of other completed projects.

Enbridge Gas has applied for Incremental Capital Module (ICM) Treatment to receive approval for the recovery of the costs for Phase 3 of the St. Laurent Project as part of the Company's 2022 Rates Phase 2 Application.[41] The OEB issued its decision on this

[39] Enbridge Gas Inc. response to I.STAFF.7 a)
[40] Enbridge Gas Inc. response to I.STAFF.8 a-b
[41] EB-2021-0148, Exhibit B, Tab 2, Schedule 1

application and did not approve the ICM treatment for the Phase 3 of the St. Laurent Ottawa North Pipeline project, on the basis that the need for the Project has not been determined at this time.[42]

Positions of the Parties

Regarding the estimated costs of the Project, OEB staff noted that it could not conclude that the estimated costs are unreasonable. OEB staff noted that, should the Project be approved, the OEB's Standard Conditions of Approval, require that Enbridge Gas file with the OEB the actual capital cost of the Project and explain variances and use of contingencies.

No other party made submissions on this issue.

Findings

Given that Enbridge Gas's application is denied based on the lack of evidence to support immediate need, the OEB is not making any specific findings regarding the reasonableness of the estimated Project cost details. However, for similar future applications, the OEB urges Enbridge Gas to provide more details about life-cycle costs including abandonment costs and the probability of future under-utilization. The OEB also encourages Enbridge Gas in future applications to elaborate on the reasons for any significant discrepancies between its cost estimate for the proposed project and other similar projects which was lacking in this application.

3.4 Environmental Impacts

Enbridge Gas retained Dillon Consulting Ltd (Dillon) to complete an Environmental Report: St. Laurent Ottawa North Pipeline Replacement Project (June 2020) (ER), which assessed the existing bio-physical and socio-economic environment in the study area, the alternative routes, proposed the preferred route, conducted public consultation, conducted impacts assessment and proposed mitigation measures to minimize the impacts.

The ER and the consultation process were conducted in accordance with the OEB's *Environmental Guidelines for Location, Construction and Operation of Hydrocarbon Pipelines in Ontario* [7th Edition, 2016] (OEB Environmental Guidelines).

[42] Decision and Order, EB-2021-0148, April 12, 2022, page 12

On July 21, 2020, the ER was made available to the Ontario Pipeline Coordinating Committee (OPCC), Environment and Climate Change Canada (ECCC), National Capital Commission (NCC), Rideau Valley Conservation Authority (RVCA) and the City of Ottawa for review and comments. The federal environmental assessment may be required for portions of the Project located on federal lands. Enbridge Gas stated that the consultation with the federal agencies is underway.[43]

Enbridge Gas indicated that there were several updates and amendments to the ER as a result of concerns identified in the review of the ER and the route and that these updates were communicated to the parties through the notices and posting of updates to the ER.

Enbridge Gas stated that it would prepare the Environmental Protection Plans (EPP) for the Project. Enbridge Gas confirmed that the EPP will include site-specific environmental management, monitoring and contingency plans to implement the mitigation and contingency measures outlined in the ER and ER Amendment and identified through the consultation process.[44]

Positions of the Parties

OEB staff submitted that Enbridge Gas has completed the ER in accordance with the OEB Environmental Guidelines. No other party made submissions on this issue.

Findings

Given that Enbridge Gas's application is denied, the environmental work carried out in support of the proposed Project is not applicable at this time and has to be updated should Enbridge Gas choose to pursue other options with the subject pipelines.

3.5 Landowner Agreements

Enbridge Gas filed the form of Working Area Agreement which has been previously approved by the OEB as part of the OEB's Decision and Order regarding Enbridge Gas's Innes Road Project. [45] Enbridge Gas also filed the form of Transfer of Easement Agreement has been previously approved by the OEB as part of the OEB's Decision and Order regarding Enbridge Gas's London Lines Replacement Project. [46] Enbridge

[43] Enbridge Gas Inc. response to I.STAFF.10 b)
[44] Enbridge Gas Inc. response to I.STAFF.12
[45] EB-2012-0438, OEB Decision and Order, April 11, 2013, pages 5-6
[46] EB-2020-0192, OEB Decision and Order, January 28, 2021, page 29

Gas has been consulting with the affected landowners and indicated that the landowners raised no concerns. Enbridge Gas expects no delays in acquiring the land rights for the Project.[47]

In addition to working area agreements and to the transfer of easement agreements, Enbridge Gas stated that it required Municipal Consent approval from the City of Ottawa to locate the pipelines within the right of way (ROW) and may require approvals and permits to occupy and use Federal lands from the National Capital Commission (NCC).

Enbridge Gas identified in its application all the permits, approvals and agreements required for the Project including the entities issuing these permits and approvals. Enbridge Gas does not anticipate any delays related to permit acquisition that could affect the Project construction schedule [48].

Positions of the Parties

OEB staff submitted that the OEB should approve the proposed forms of agreements as both forms were previously approved by the OEB. No other party made submissions on this issue.

Findings

The OEB finds that it is not necessary to make a finding in this regard given that it has denied the application.

3.6 Indigenous Consultation

In accordance with the OEB's Environmental Guidelines, Enbridge Gas contacted the Ministry of Energy Northern Development and Mines (MENDM) in respect to the Crown's duty to consult related to the Project, on December 3, 2019. The MENDM, by way of a letter, delegated the procedural aspects of the Crown's Duty to Consult for the Project to Enbridge Gas on January 30, 2020 (Delegation Letter). In the Delegation Letter the MENDM identified two Indigenous communities that Enbridge Gas should consult in relation to the Project:

- Algonquins of Ontario
- Mohawks of Akwesasne

[47] Enbridge Gas Inc. response to I.STAFF.18 a) and b)
[48] Enbridge Gas Inc. response to I.STAFF.17 a)

Enbridge Gas provided the MENDM with its Indigenous Consultation Report (ICR) for the Project on March 2, 2021 and updated it on March 4, 2021. The ICR states that Algonquins of Ontario and Mohawks of Akwesasne expressed no concerns or issues related to the Project.

On April 13, 2021, Enbridge Gas received a letter from the Ministry of Energy indicating that it reviewed the ICR and that, in its opinion, the procedural aspects of consultation undertaken by Enbridge Gas to date are satisfactory (referred to as Sufficiency Letter or Opinion Letter).

The Algonquins of Ontario reviewed the Stage 1 Archaeological Assessment report. Enbridge Gas responded to their comments and is committed to involve the Algonquins of Ontario in the Stage 2 Archaeological Assessment field work and provide capacity funding. Enbridge Gas noted that the Algonquins of Ontario and the Mohawks of Akwesasne participated in virtual monitoring associated with the field work for Phase 3 and Phase 4 Stage 2 Archaeological Assessments. Enbridge Gas confirmed its commitment to involving Indigenous communities in Archeological Assessment work.[49] In response to an OEB staff interrogatory, Enbridge Gas stated that no issues or concerns with the Project were raised by the Algonquins of Ontario or the Mohawks of Akwesasne since September 10, 2021. Enbridge Gas also noted that it received no correspondence or communication from the Ministry of Energy since the Opinion Letter was issued on April 13, 2021.[50]

Positions of the Parties

OEB staff submitted that Enbridge Gas appeared to have made efforts to engage with affected Indigenous groups and no concerns that could materially affect the Project had been raised through its consultations to date. OEB staff observed that Enbridge Gas appeared to be cooperating with the Indigenous communities during the consultation process and that it made commitments to the Indigenous communities related to the Project. OEB staff stated that it was not aware of any potential adverse impacts of the Project to any Aboriginal or treaty rights.

No other party made submission on this issue.

[49] Enbridge Gas Inc. response to I.STAFF 19 d)
[50] Enbridge Gas Inc. response to I.STAFF 19 b) and c)

Findings

The OEB finds that it is not necessary to make a finding in this regard given that it has denied the application.

3.7 Conditions of Approval

OEB staff sought comments from Enbridge Gas on the OEB's Standard Conditions of Approval for leave to construct applications[51]. In response, Enbridge Gas agreed with the Standard Conditions of Approval.

Section 23 of the OEB Act permits the OEB, when making an order, to impose such conditions as it considers appropriate.

OEB staff submitted that, should the OEB grant leave to construct the Project, the approval should be subject to the Conditions of Approval as proposed in the OEB staff submission.

Findings

Since leave to construct the subject pipelines is not being granted by the OEB to Enbridge Gas, Conditions of Approval are not applicable and the OEB is making no findings on the draft Conditions of Approval.

[51] The link to the OEB Standard Conditions for section 90 applications was also provided in the notice of application together with the Standard Issues List for section 90 applications.

4 ORDER

THE ONTARIO ENERGY BOARD ORDERS THAT:

1. Enbridge Gas Inc.'s application pursuant to section 90(1) of the OEB Act, for a leave to construct the Project in the City of Ottawa as described in its application is denied.

2. The information which had previously been designated by the OEB as confidential on an interim basis shall be treated as confidential on a final basis.

3. Parties in receipt of confidential information shall either return the subject information to the Registrar and communicate to the Enbridge Gas Inc. that they have done so or destroy the information and execute a Certificate of Destruction, following the end of this proceeding. The Certificate must be filed with the Registrar and a copy sent to Enbridge Gas Inc.

4. Eligible intervenors shall file with the OEB and forward to Enbridge Gas Inc. their respective cost claims in accordance with the OEB's *Practice Direction on Cost Awards* on or before **May 19, 2022**.

5. Enbridge Gas Inc. shall file with the OEB and forward to intervenors any objections to the claimed costs of the intervenors on or before **May 26, 2022**.

6. If Enbridge Gas Inc. objects to any intervenor costs, those intervenors shall file with the OEB and forward to Enbridge Gas Inc. their responses, if any, to the objections to cost claims on or before **June 2, 2022**.

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-2020-0293** 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 File documents online 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.
- Cost claims are filed through the OEB's online filing portal. Please visit the File documents online page of the OEB's website for more information. All participants shall download a copy of their submitted cost claim and serve it on all required parties as per the Practice Direction on Cost Awards.

All communications should be directed to the attention of the Registrar 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, Zora Crnojacki at Zora.Crnojacki@oeb.ca and OEB Counsel, James Sidlofsky at James.Sidlofsky@oeb.ca.

Email: registrar@oeb.ca

Tel: 1-877-632-2727 (Toll free)

DATED at Toronto May 3, 2022

ONTARIO ENERGY BOARD

Nancy Marconi
Registrar

ENBRIDGE GAS INC.

Answer to Interrogatory from
Pollution Probe (PP)

Interrogatory

Question(s):

Enbridge has indicated that RNG projects may not be included in the AMP or undergo the IRP considerations as part of the AMP process [EB-2022-0203, Exhibit I.PP.3]. Please identify which RNG projects are excluded/included from the AMP and related process. Please explain why RNG projects are excluded.

Response:

RNG projects are excluded from the Asset Management Plan as they are not part of Enbridge Gas's regulated operations.

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

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.

<u>Definition and Scope of IRP for Enbridge Gas</u>

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

[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:

- <u>Risk management</u> - 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:

- <u>Reliability and safety</u> – 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

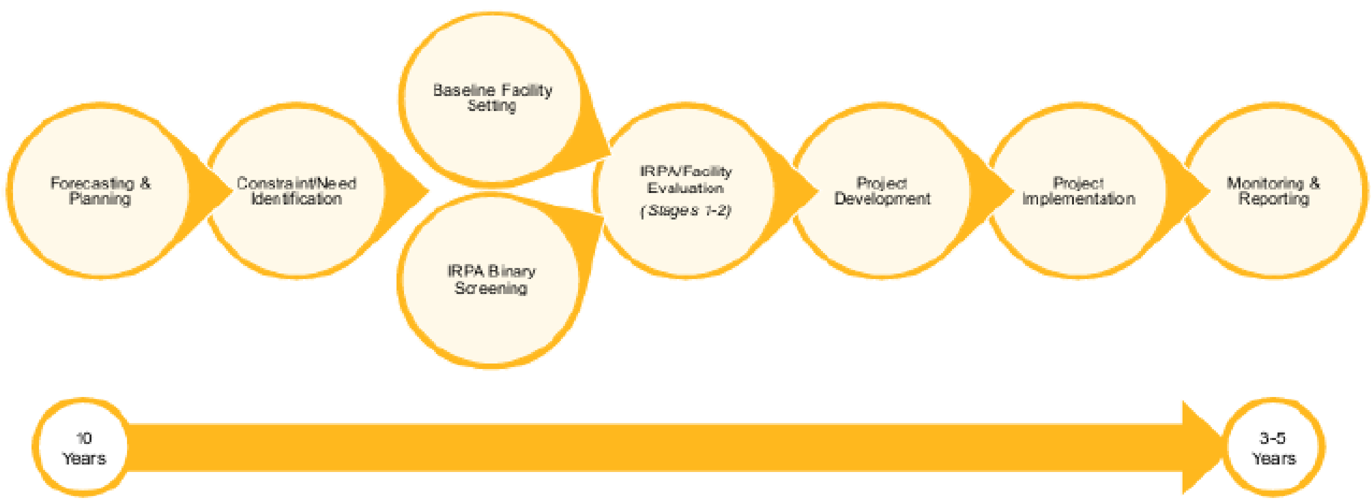
2. Binary Screening Criteria

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.

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[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.

Specific screening criteria

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.

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[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.

<u>Potential Stranding of Assets</u>

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

[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]

[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

[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

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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

[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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TABLE OF CONTENTS

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.*

Pipeline Replacement and Relocation Projects

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").

Binary & Technical Screening

Introduction

The IRP Binary Screening and Technical Evaluation described in this paper are conducted using the direction and guiding principles provided by the Ontario Energy Board in the IRP Decision and Order (EB-2020-0091). The investments considered as part of this Binary Screening and Technical Evaluation process include investments within Enbridge's Asset Management Plan and are limited to regulated Enbridge Gas investments.

As Enbridge has worked through its first IRP Binary Screening and Technical Evaluation of the investments in the Asset Management Plan, certain learnings have been identified. These learnings have led to some investments being removed either ahead of the Binary Screening (this was identified as "Initial Screening") or in the process of completing the Technical Evaluation (this was identified as "Initial Technical Evaluation"). The rationale for the removal of these investments from further evaluation is outlined in this document. In future Asset Management Plan (AMP) investment evaluations, Enbridge Gas will systematically apply these learnings so that time can be focused on the geographical areas and investment types that are most likely to yield an IRP Plan that is both Technically and Economically Feasible.

Initial Screening

Ahead of the Binary Screening, investments in non-Gas Carrying assets were removed. These investments are in **Real Estate & Workplace Services**, **Fleet & Equipment**, and **Technology & Information Services**.

Binary Screening based on the OEB Decision

Based on Binary Screening criteria provided by the OEB, investments were removed from further evaluation.

Investments deemed Emergent Safety Issue
These investment dollars are not yet tied to specific investment projects. Most of the dollars budgeted within this category are what Enbridge Gas refers to as "programmatic spend", which means that they are dollars budgeted to be spent on emergent safety issues when they arise. The programmatic dollars budgeted for Emergent Safety Issues are allocated by region and based on historical spend. Emergent safety issues that this budget would be spent on include replacing mains and services after a leak has occurred. Once an asset is leaking the issue must be addressed quickly for safety reasons and to avoid further GHG emissions. There is no time for an IRP Plan to be developed and implemented.

- ***Investments failing based on Timing***
  These investment dollars are not yet tied to specific investment projects. Most of the dollars budgeted within this category are what Enbridge Gas refers to as "programmatic spend" and are to be spent on various Integrity Management Programs and Station Replacement projects as they arise. The programmatic dollars budgeted are based on historical spend and known drivers such as changes to codes and standards. Specific projects in this category include (1) Integrity Digs, (2) Integrity Retrofits, and (3) the replacement of bypassing valves at Storage Facilities. Although most projects that arise from the Integrity Management Program will not be suitable for IRPA's (see below for a description of these investments and why the investment type and timing would not allow for an IRPA – see Table 1 below, specifically Rows 13, 14, and 27), **any pipeline replacements identified will be subject to the IRP Binary Screening and Technical Evaluation process**.

- ***Investments failing based on $ Threshold***
  As noted in the OEB Decision, "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."[1] Enbridge used a $ value of $2M to screen projects out at this stage. In addition, as part of this binary screen step, programmatic budgets that have an estimated annual spend of less than $2M were screened out. Programmatic budgeted spend that was removed at this stage includes main replacement and main relocation programmatic spend. The annual main replacement programmatic spend budget is based on historical spend and allows Regions to respond to leaking mains and services. Note: moving forward, Enbridge Gas will remove all spend for leaking mains and services through the Emergent Safety Issue category as noted above. The Main Relocation programmatic spend budget is based on the capital expenditures required to replace or relocate segments of pipeline to accommodate municipal infrastructure work. Any specific Main Relocation investments that are identified will be subject to the IRP Binary Screening and Technical Evaluation Process. In addition to the main replacement and relocation programmatic spend removed at this stage, there are several other small programmatic budgets that were screened out. These other small programmatic budgets are designed to address specific issues that arise annually on Enbridge Gas' facilities.

- ***Customer-Specific Build***
  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

[1] EB-2020-0091 Decision and Order, Integrated Resource Planning Proposal, July 22, 2021, p. 49

long-term firm services delivered by such facilities (including new subdivision or small main extensions) then it is not appropriate to conduct IRP analysis for those projects."[2] In this first IRP Binary Screen and Technical Evaluation, Enbridge Gas chose not to Binary Screen out (1) customer-specific build investment projects which includes the Customer Connections budget. The Customer Connections budget is informed by the anticipated number of customer additions and the historical cost to add customers to the system.

- ***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."[3] As noted in the Asset Management Plan[4], Community Expansion and Economic Development projects are not included in the Asset Management Plan and there will be no IRP evaluation.

Technical Evaluation

Enbridge has been completing detailed Technical Evaluation project reviews of its investments to verify that the forecasted needs haven't changed, the project costs are sufficient, and that the project drivers haven't changed. While completing this detailed project review, Enbridge has identified certain trends and groupings of projects for which IRPA's will not be effective. The rationale for this is described below and in Table 1. In the future, Enbridge will remove these investments systematically from IRP Technical Evaluation.

As the Technical Evaluation Project Reviews proceeded, the Enhanced Distribution Integrity Management Program (EDIMP) was being established and matured. As this program has clarified its scope, some of the planned replacement projects will be within that scope and there is a potential for their scope and timing to change (increase or decrease, sooner or later), as a result of the EDIMP findings. This could, in turn, affect their treatment in the IRP Binary Screen and Technical Evaluation Process.

Technical Evaluation Project Reviews will continue to be completed on the remaining investments. These continued detailed Technical Evaluation Project Reviews could identify additional categories of work for which there are no technically feasible IRPA's. Any additional categories would be described in a future draft of Enbridge's "Binary and Technical Evaluation Screening Process".

Initial Technical Evaluation

As noted above, as projects moved through the Technical Evaluation Project Review, Enbridge Gas identified categories of investments that do not have a technically feasible IRP alternative (IRPA). The first five categories were identified, and their associated projects were removed from further Technical Evaluation, in what Enbridge Gas has labelled its "Initial Technical Evaluation". Provided below are the categories of projects that, through this Initial Technical Evaluation, have been deemed not to have a technically feasible IRPA.

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[2] EB-2020-0091 Integrated Resource Planning Proposal, Decision and Order July 21, 2021, p. 44.
[3] EB-2020-0091 Integrated Resource Planning Proposal, Decision and Order July 21, 2021, p. 48.
[4] EB-2022-0200 Exhibit 2, Tab 6, Schedule 2, p. 282

Customer Connections

Enbridge reviewed the investments in this category to see if IRPA's could be identified and, upon review, has confirmed that they should be screened out through the Binary Screening. In its Technical Evaluation, Enbridge Gas determined that implementing an IRPA could not reduce the size of the distribution mains, services or regulating equipment, as these cannot be downsized any further. In addition, there are no non-gas IRPAs available within the current IRP Framework that can be offered to avoid the customer connection service being requested. Note that any associated main reinforcement investments will go through the Binary Screening and Technical Evaluation process.

Compressor Stations

The investments in the Compression Stations Asset Class are related to the maintenance of the existing fleet of compressors and include the periodic OEM prescribed overhauls and replacement of components that are not performing as intended or are obsolete. Enbridge Gas expects that technically feasible IRPA's will only be identified for Compressor Station investments where growth is a driver.

Hydrogen Blending

There are investments in the AMP related to the use of hydrogen in the distribution system. Since these investments are focused on reducing the carbon footprint of the existing transmission and distribution system, they cannot be offset by IRPA's. Enbridge Gas will remove investments in the GTH – Hydrogen Blending Asset Class/Program from Technical Evaluation going forward.

- Expansion of the existing Low Carbon Energy Project (LCEP),
- A Hydrogen Grid Study to establish what would be required to prepare the natural gas distribution system for the introduction of more hydrogen,
- A study to establish how the company could use hydrogen to fuel compressors, and
- A study to establish how the company could use hydrogen to station heating.

Storage Pools & Wells

The investments in the Asset Management Plan for Wells and Pools relate to maintenance and compliance driven upgrades to allow for ongoing deliverability from the storage pools. Enbridge Gas will remove these investments from the IRP Technical Evaluation moving forward as the projects relate to drilling of an observation well for compliance reasons and work that arises annually from the Integrity Management Program.

Project Status

Through the Technical Evaluation Project Review, Enbridge Gas identified several investments that would not have an IRP Technical Evaluation completed due to their project status. Projects that fall within this category are those that are already under construction, already granted Leave to Construct by the Ontario Energy Board or are projects that have been cancelled.

Technical Evaluation

As Enbridge continued to complete its Technical Evaluation Project Review of each investment for the purpose of completing an IRP Technical Evaluation, further categories of spend were identified for which no technically feasible IRPA could be established. These categories are described below and in the analysis of future Asset Management Plans, these will be systematically removed (with noted exceptions) so that better progress can be made on the areas for which a technically feasible IRP may exist.

Distribution Station condition related, IRPA’s not applicable

Through the Technical Evaluation Project Review, the Distribution Station investments were assessed to confirm that the projects were driven by the condition and not by growth. These Distribution Station Condition related projects are prioritized based on inspections that evaluate the condition of various components (regulators, valves, piping, etc) and systems (heating, odourant, communications, etc) at the stations. Sometimes, the specific projects are time constrained and low in dollar value meaning that they fail at the binary screening stage. For larger projects, an understanding of the impact on upstream and downstream facilities is required and replacement size for size is usually preferable – particularly if a full station replacement is not being planned. As such, all condition related station rebuilds, and replacements will be excluded from IRP Technical Evaluation. **However, any station rebuilds that involve an element of growth will be included in IRP Evaluation**.

See investment description – IRPA's not applicable for CNG

Through the Technical Evaluation Project Review, these investments were assessed to confirm that they are related to the ongoing replacement and upgrade of CNG facilities to fuel Enbridge’s natural gas vehicles. These needs cannot be replaced through IRPA’s and these investments will not proceed through IRP Technical Evaluation going forward.

See investment description, IRPAs not applicable

Through the Technical Evaluation Project Review, it was established that there would not be a technically feasible IRPA for a set of investments. This set of investments are classified as **“See investment description, IRPAs not applicable”**. Investments in this category are described below along with the reasons that they will not yield a technically feasible IRPA. Where applicable, there are notes as to how these will be systematically removed prior to IRP Technical Evaluation in future.

Table 1 – Description of Investments Screened out of the Technical Evaluation Project Review

	Sub-category	Asset Class	Asset Program	Description
1	AMI Pilot	Utilization	UTIL-Monitoring Systems	The AMI Pilot will establish the technical and economic benefits related to the installation of AMI meters and associated infrastructure. No technically feasible IRPA's can replace this spend and the investment will be removed from further Technical Evaluation.
2	AMP Fitting	Distribution Pipe	DP-Service Relay	An AMP fitting is a mechanical fitting installed between 1969 and 1984, on below ground residential gas service lines, to transition from a plastic service line to a copper riser. Locations with an AMP Fitting are identified annually and prioritized based on risk. As such the investments should be excluded based on timing and the fact that individual service replacements cannot be offset by IRPA's.
3	Class Location	Distribution Pipe & Transmission Pipe & Underground Storage	DP-Class Location TPUS-Class Location	This is one of the Integrity Management Programs in which the spend is held in a Programmatic spend budget to cover specific projects that are identified each year. Class locations projects arise when a facility needs to be relocated because of increased development and associated population density around the facility. Going forward this programmatic spend budget will be removed from IRP Technical Evaluation, but any **specific pipeline replacements will be included for IRP Evaluation**
4	Compression Stations	Compression Stations	All	See section above on Compression Stations
5	Corrosion	Distribution Pipe	DP-Corrosion	This programmatic spend covers the replacement of depleted anodes, work arising from bridge crossing inspections, and repairs to rectifier beds. Once found, these problems must be addressed quickly to avoid degradation of the pipe and, as such, will be removed from IRP Evaluation based on timing.
6	Depth of Cover Program	Transmission Pipe & Underground Storage	TPUS-Integrity	This programmatic spend budget is for facilities that are identified each year as exposed or shallow leading to an increased risk of 3rd party damage. Once identified the pipeline must be lowered, replaced, or otherwise protected to control risk. Going forward this programmatic budget spend will be excluded from IRP Technical Evaluation, but any **resultant pipeline replacements be included for IRP Evaluation.**
7	District Station	Distribution Stations	DS-Station Rebuilds & B & C Stations	These investments hold $ for specific station rebuild investments that have been identified through annual inspections and that have been prioritized for rebuild based on condition. Currently there are 53 such investments, each of which failed the binary screen based on the $ threshold and because the asset condition once identified, are planned for the following year. As such they will be excluded based on Timing going forward.

8	Farm Taps	Utilization	UTIL-Regulator Refit	This is programmatic spend that is budgeted to cover the costs of remediating situations in which there are problems with the first or second cut of the regulation at a customer's premise. These are repaired as they are found and should be eliminated based on timing.
9	Facilities Integrity Management Program (FIMP)	Distribution Stations	DS-Integrity	This is programmatic spend that is budgeted to cover the costs of large station inspections that must be completed annually to scope the extent of work that is required at each large station investment identified in the AMP. Going forward, all such Station programmatic spend that is driven by condition, end-of-life, and compliance will be removed from IRP Technical Evaluation.
10	Fire Suppression	Distribution Stations	DS-Gate, Feeder & A Stations	These investments relate to the installation of Fire Suppression at Distribution Stations with Odourant. 3 similar investments were eliminated at Binary Screening because of Timing, and another was eliminated at Binary Screening because of the $ threshold. Going forward all such Station programs that are driven by condition, end-of-life, and compliance will be removed from IRP Technical Evaluation.
11	Geohazard	Distribution Pipe	DP-Integrity	This integrity management programmatic spend is budgeted to cover the costs related to identifying pipelines that must be replaced because of risks related to geohazards. This spend will be excluded from IRP Technical Evaluation going forward but **any resultant replacement projects will be included in IRP Technical Evaluation.**
12	Independent Asset Integrity Review (IAIR)	Distribution Pipe & Transmission Pipe & Underground Storage	DP-Integrity, TPUS-Integrity	This is programmatic spend that is budgeted for work that results from the Independent Asset Integrity Review. Although the programmatic spend budgeted here cannot be assessed for IRP Alternatives, **any resultant pipeline replacements will be included in the IRP Technical Evaluation.**
13	Integrity Digs	Distribution Pipe & Transmission Pipe & Underground Storage	DP-Integrity, TPUS-Integrity	This programmatic spend is budgeted to cover the costs related to repairs and replacements that are identified through in-line inspections. This programmatic budgeted spend will be excluded from future IRP Technical Evaluation but **pipeline replacement projects found as a result of the integrity dig work will be included in the IRP Evaluation**.
14	Integrity Retrofit	Distribution Pipe, Distribution Stations & Transmission Pipe & Underground Storage	DP-Integrity, DS-Integrity, TPUS-Integrity	This is programmatic spend that is budgeted for installing pig launchers and receivers, allowing annual in-line inspection to be accomplished more easily and the life of transmission pipelines to be potentially extended. This work takes place at stations and does not affect the distribution system itself. No technically feasible IRPA's exist for this type of work, and it will be removed from the Technical Evaluation going forward.

15	Inside Room Regulators (IRR)	Distribution Stations	DS-Inside Regulator & ERR Program	This is programmatic spend that is budgeted for remediation of inside regulation sets based on risk. There is no technically feasible IRPA that could address this need and they will be removed from the Technical Evaluation going forward.
16	Large stations	Distribution Stations	DS-Gate, Feeder & A Stations	These stations are identified through inspections and prioritized for rebuild based on condition. Each year, this programmatic spend is converted into specific projects. **Any identified investments for which growth plays a role will be included in the IRP Evaluation.** It should be noted that there is also the possibility that reduced load will drive some investment in stations.
17	Liquified Natural Gas (LNG)	LNG	All	These investments relate to the maintenance of the Hagar LNG facility that is used to peak shave the load in the Sudbury area. Unless driven by Growth, all investments at the Hagar facility will be excluded from the Technical Evaluation moving forward.
18	Low Pressure Delivery Meter Sets (LPDMS)	Utilization	UTIL-Remediation	This is programmatic spend budgeted to cover the inspection and remediation of Low-Pressure Delivery Meter sets, which are usually at commercial customer locations. Similar investments were excluded at binary screening based on the dollar threshold. Going forward, these investments will be removed from the Technical Evaluation.
19	Main & Service Repl - Leaking	Distribution Pipe	DP-Service Relay	Similar investments in the EGD Rate Zone were excluded at Binary Screening and going forward these too will be excluded at Binary Screening as Emergent Safety Issue. Aside from the safety concern, leaks must be addressed quickly to avoid GHG's.
20	Meter exchanges	Utilization	UTIL-Regulator Refit	This programmatic spend is budgeted to cover the costs of replacing meters through the Measurement Canada approved processes.
21	Maximum Operating Pressure (MOP) Verification	Distribution Pipe & Transmission Pipe & Underground Storage	DP-Replacements, TPUS-Replacements	This programmatic spend is budgeted to cover the replacement of pipelines where this may be required because of a review of records for pipeline systems operating above 30 per cent SMYS. Once the MOP has been identified and based on the associated risk, the pressure in these pipelines may need to be reduced until the pipeline can be replaced. The programmatic budgeted spend will be removed from Technical Evaluation going forward but **specific pipeline replacement projects will be included in IRP Evaluation when they are identified**.
22	Odourant Program	Distribution Stations	DS-Gate, Feeder & A Stations	These investments are for the upgrade of odourant systems at stations. Similar investments failed at binary screening because of timing and because of the dollar threshold. Going forward all such Station programs that are driven by condition, end-of-life, and compliance will be removed from IRP Technical Evaluation.

23	Pressure Factoring Metering (PFM) Program	Stations	DS-Station Rebuilds & B and C Stations	This programmatic spend is budgeted to cover the costs of PFM stations that require a bypass. There is no technically feasible IRPA to address this need and this programmatic budgeted spend will be removed from Technical Evaluation moving forward.
24	Re-class to CNG	Distribution Stations	DS-CNG	One investment relates to CNG and should have been allocated to the "See investment description – IRPA not applicable for CNG investments".
25	Relocation Program	Distribution Pipe	DP-Relocations	This programmatic spend has been budgeted to cover the costs of projects that are identified annually in response to the requirements of municipalities and other agencies. This programmatic budgeted spend will be removed from Technical Evaluation moving forward but **specific pipeline replacement projects will be included in IRP Evaluation**.
26	Remote Terminal Units (RTU)	Distribution Stations	DS-Gate, Feeder & A Stations	These investments are for the replacement of Remote Terminal Units that are no longer supported by the manufacturer. Similar investments were eliminated at Binary Screening because of Timing. Going forward all such Station programs that are driven by condition, end-of-life, and compliance will be removed from IRP Technical Evaluation.
27	Storage Facility	Transmission Pipe & Underground Storage	TPUS-Improvements	As noted above, investments related to Storage Pools and Wells will be excluded from Technical Evaluation going forward unless they are driven by growth.
28	Telemetry	Distribution Stations	DS-Gate, Feeder & A Stations	These investments are for telemetry at distribution stations. Similar investments failed at binary screening because of the dollar threshold. Going forward all such Station programs that are driven by condition, end-of-life, and compliance will be eliminated from IRP Technical Evaluation.
29	Vintage Steel Main (VSM)	Distribution Pipe	DP-Replacement	There is a programmatic spend budgeted for Vintage Steel Main projects that have not yet been identified. Although this programmatic spend will not- be put through Technical Evaluation **projects, once identified, will go through IRP Evaluation.**
30	Well Laterals	Transmission Pipe & Underground Storage	TPUS-Integrity	As noted above, investments in Storage Pools & Wells, and their associated Integrity Management Programs will be similarly excluded from Technical Evaluation.

Scope is NPS 2, cannot downsize further or retire

The existing scope is already NPS and thus cannot be further downsized. These investments were then reviewed to determine whether they could be retired. These scopes had services coming off the pipe that needed to be maintained to serve those customers and thus cannot be retired. Since the pipe size can't be reduced beyond NPS 2 and the pipe couldn't be eliminated, IRP wouldn't impact the project scope, so these were failed.

Potential to be downsized to NPS 2. Further assessment closer to ISD

When completing Technical Evaluation, it was determined that the project scope could potentially be replaced with NPS 2 prior to any IRP assessment. If the pipe size can be reduced, then IRP will not be applicable to the project scope; the scope will be confirmed when the project enters the detailed design phase.

Potential to be downsized to NPS 2, but need to avoid bottlenecks and maintain system resiliency

A portion of the project scope could potentially be replaced with NPS 2 prior to any IRP assessment. It is recommended that pipe size is maintained for segments of trunk main and for system resiliency. Thus, IRP is not applicable to the project scope; the scope will be confirmed when the project enters the detailed design phase. These projects may benefit from having a broader assessment of the needs in the area and the potential for reductions via a geographically focused IRP Plan. This type of analysis was beyond the capacity of the team for this first pass through the IRP Technical Evaluation process but is an area that will be explored in the future.

ETEE could reduce pipe size, but it is a trunk main

There are investments for which ETEE could potentially reduce the pipe diameter, but this would introduce a bottleneck in a trunk main which is not desirable from a network operations perspective.

Timing – Market Based Supply Side not available

Some investments failed because they are required in the near term (1-3 years) and there is no technically feasible supply-side alternative that can meet the need.

Summary

Enbridge is reviewing 2023-2032 investments through a combination of both detailed project reviews and systematic methods through which groups of investments are prioritized for evaluation or eliminated. Through these evaluations, lessons have been learned, which are incorporated in this document to develop guidance for evaluations going forward. At this time (for the reasons discussed above), the following Asset Class/Asset Programs will be screened out systematically when future AMPs are reviewed:

- Compression Stations
- Customer Connections
- Distribution Pipe (Programmatic Spend)
    - Class Location
    - Corrosion
    - Integrity
    - Service Relay
- Distribution Stations (note that any Stations with an element of Growth will be moved to the Growth Asset Class)
- Growth
    - Hydrogen Blending
- LNG
- Transmission Pipe & Underground Storage (Programmatic Spend)
    - Class Location
    - Improvements
    - Integrity
    - Land/Structures – Improvements
- Utilization

As the remainder of the Technical Evaluations are completed as well as economic evaluation and pilots, it is expected that this document will be updated for use on subsequent cycles of investment evaluation.

Legend	
Mandatory	Do Not Fill
Fill If Applicable	

IRP TECHNICAL REVIEW
(Distribution Pipe Reinforcement / Replacements Projects)

C55 Investment #	30536	Asset Class	Growth
Project Name	SRP_Southeast_Cambridge_Guelph Ave_Reinforcement_NPS6_1000m_420kPa		
Operating Area (EGI)	Div_7 - Waterloo	In Service Date (ISD)	10/1/2026
City/Town	Cambridge	IRP Review Lead	HT
Coordinates	43.436754, -80.312030	DOE Review Lead	SE
DOE Supervisor Check	KL	Date of Review	2/9/2023

Scope Refinement

Existing Scope (size for size replacements, or SRP reinforcement)

1000m of NPS6 PE on Guelph Ave

Modified Scope (Can scope be smaller or shorter for construction year / in-service prior to consideration of IRPAs)

Due to system and demand changes, project timing can be deferred and/or shortened.

IRP General Review

Is this a replacement project?	No
Is the majority of the project NPS 2?	No
Are there services on this pipeline that cannot be served elsewhere?	No
Are there external factors driving the project schedule?	No

Comments

N/A

Skip greyed out sections (If applicable)

Supply Side - CNG

Is the In Service Date (ISD) - Current day more than 3 Years	Yes
Does system demand decline in 5 years from in-service date?	No
Can CNG be leveraged to defer the project?	Yes

If CNG is implemented for up to 5 years, is the following possible for the project scope?

Elimination	No	Comments	
Reduction	Yes	Comments	Reduction is possible
Deferral	Yes	Comments	Deferral is possible

Potential Scope Changes

Any scope reduction will depend on the efficiency/peak hour reduction of ETEE measures