ONTARIO ENERGY BOARD

**October 2025**

## Staff Discussion Paper

# Integrated Resource Planning Framework Review

**EB-2025-0125**

Ontario

Ontario Energy Board

# TABLE OF CONTENTS

# EXECUTIVE SUMMARY

### IRP Framework Review Consultation

The OEB's Integrated Resource Planning (IRP) Framework, issued in 2021, provides direction to Enbridge Gas as it considers IRP to meet its system needs.

On March 27, 2025, the OEB announced that it was launching a consultation to support a review and evaluation of the IRP Framework. The OEB indicated that the review would be informed by challenges and progress in implementing the IRP Framework, an assessment of the impacts to date (including benefits to ratepayers), the IRP Pilot Project application and IRP-related evidence and submissions received during other proceedings. The first step in this consultation is an OEB staff report (this document) assessing progress implementing the IRP Framework and proposing updates to the IRP Framework.

Stakeholders are invited to submit comments that address the OEB staff proposals in this discussion paper or provide additional suggestions regarding the IRP Framework. The OEB will consider stakeholder comments and subsequently determine next steps in the IRP Framework review.

### Overview of Current IRP Framework

IRP is a planning strategy and process that considers both traditional infrastructure solutions (such as pipelines) and IRP Alternatives (sometimes referred to as non-pipeline alternatives in other jurisdictions), including the interplay of these options, to address the system needs of Enbridge Gas's regulated operations and identifies and implements the option that is in the best interest of Enbridge Gas and its customers.

Key features of the current IRP Framework include:

- Guiding principles regarding reliability and safety, cost-effectiveness, public policy, optimized scoping and risk management.
- Guidance on what types of IRP Alternatives Enbridge Gas may consider to meet an identified system need. This includes demand-side alternatives, such as geotargeted energy efficiency programs, demand response programs, interruptible rates, and supply-side alternatives that could include compressed natural gas, renewable natural gas, or market-based alternatives. As part of this first-generation IRP Framework, the OEB determined that it was not appropriate to provide funding to Enbridge Gas for electricity IRP Alternatives.

- A four-step IRP Assessment Process (including a technical evaluation and an economic evaluation) that 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.
- A new approval process for IRP Plans to address a system need, with information requirements like what is found in a Leave to Construct application.
- Requirements for stakeholder engagement (including the establishment of an IRP Working Group) and Indigenous engagement and consultation.

**IRP Progress and Impacts to Date**

Enbridge Gas has made concerted efforts to meet the OEB's expectations in the IRP Framework, including:

- Integrating consideration of IRP Alternatives to address system needs into its Asset Management Planning process.
- Designing, receiving OEB approval for, and beginning implementation of an IRP pilot in the Southern Lake Huron region.
- Designing an additional pilot examining pruning segments of the natural gas system, as an alternative to pipeline repair/replacement.
- Taking actions to increase potential customer adoption of interruptible rates.
- Developing a preliminary approach to assessing stranded asset risk for traditional infrastructure investments.

Enbridge Gas has only implemented one small IRP project that addressed a system need and thereby avoided or deferred infrastructure spending.

To date, no pipeline projects requiring Leave to Construct approval have been avoided through selection of an IRP Plan as an alternative to the pipeline project. Similarly, for the large number of system needs in Enbridge Gas's Asset Management Plan (AMP), in only one instance to date has an IRP Plan been selected as the preferred option to address the need, although some projects still have technical or economic evaluations pending.

There was a delay in finalizing the economic evaluation methodology used to assess the cost-effectiveness of IRP Alternatives and delays implementing IRP pilot projects relative to the timing expectations in the IRP Framework. An opportunity to address these challenges through a proposed new requirement for Enbridge Gas to file an IRP Implementation Plan is discussed under topic 1 (update and oversight of the IRP Framework).

## Evolving the IRP Framework

Several policy factors including the removal of the Federal Carbon Charge suggest that, at least in the near-term, there may be fewer opportunities for cost-effective deployment of IRP Alternatives than may have been anticipated when the IRP Framework was originally issued.

Nevertheless, OEB staff believe that continued investigation and consideration of IRP Alternatives in system planning is of value to natural gas customers and is aligned with the Ontario government's Integrated Energy Plan (IEP) *Energy for Generations* and its core principles - affordable, secure, reliable and clean energy. Proposed revisions to the IRP Framework are informed by the Natural Gas Policy Statement in particular, including direction that "Ontario will continue to support the important role of natural gas in Ontario's energy system and economy while pursuing options to lower costs and reduce emissions"[1].

OEB staff proposes an incremental evolution of the existing IRP Framework, including several changes to the IRP Framework that are likely to better reflect the general principle, set out in the first-generation Framework, that Enbridge Gas should be implementing the solution that is in the best interest of Enbridge Gas and its customers. OEB staff proposals would also enable Enbridge Gas to continue efforts to gain learnings on IRP, even where it is not the most cost-effective approach in the near-term to address system needs. This would better position the OEB and Enbridge Gas should the opportunity arise to deploy IRP at greater scale. Other proposals, informed by learnings from the implementation to date of the current IRP Framework, will ensure IRP-related regulatory obligations and processes evolve to remain reasonable and efficient.

Taken together, these proposals are intended to continue to drive the adoption of the most prudent infrastructure or IRP Alternative to meet a given system need, while improving the IRP value-to-effort ratio and positioning the natural gas sector to quickly and effectively adapt to various potential future scenarios.

Specific OEB staff proposals regarding an evolved IRP Framework are described below, grouped into the four topics previously identified by the OEB as the focus of this consultation.[2]

[1] Ontario's Integrated Energy Plan, p.96

[2] A full list of discussion questions in regard to these proposals is included in Appendix A of the discussion paper.

## Topic 1: Update and Oversight of the IRP Framework

OEB staff proposes that an update to the IRP Framework is desirable, and seeks stakeholder input on the following questions:

- What procedural approach should be taken for updating the IRP Framework (e.g., through adjudication or as a policy document)?
- Should the updated IRP Framework be applicable to Enbridge Gas only, or to all rate-regulated natural gas distributors (i.e., inclusive of EPCOR Natural Gas Limited Partnership)?[3]

OEB staff proposes a new requirement for Enbridge Gas to file a forward-looking IRP Implementation Plan compatible with the updated IRP Framework, covering a defined period (to be determined, e.g., three years) to be reviewed through adjudication. The IRP Implementation Plan would outline actions and priorities for this period, consider supporting IRP-related policies and guidance documents developed by Enbridge Gas, and could include funding requests to use IRP to address specific system needs or for innovation-related proposals. The OEB expects that having a dedicated regulatory proceeding to review Enbridge Gas's actions and approach to implementing the IRP Framework (including guidance documents which do not have consensus support among the IRP Working Group) will be more efficient and lead to more consistent outcomes for subsequent project-specific applications that involve consideration of IRP (such as Leave to Construct proceedings). Another option would be to encompass the requirement for an IRP Implementation Plan within Enbridge Gas's rebasing application.

OEB staff proposes that the IRP Working Group would continue, with a defined role focused on reviewing and providing substantive input on a draft of the IRP Implementation Plan (prior to adjudication).

[3] Throughout this discussion paper, the descriptions of OEB staff proposals for an updated IRP Framework refer to the expectations for Enbridge Gas (consistent with the existing IRP Framework). Should the OEB determine that an updated IRP Framework will apply to all rate-regulated natural gas distributors, the OEB staff proposals would generally also apply to all rate-regulated natural gas distributors. However, if OEB staff's proposal for an IRP Implementation Plan is incorporated into the updated IRP Framework, OEB staff would recommend that the requirement for an IRP Implementation Plan for EPCOR not take effect until a later date, following approval of Enbridge Gas's initial IRP Implementation Plan.

## Topic 2: Innovation

OEB staff supports providing flexibility in the updated IRP Framework for Enbridge Gas to propose and seek cost recovery for innovation-related IRP proposals. For the purposes of the updated IRP Framework, OEB staff propose to define innovation-related IRP proposals as discrete initiatives intended to advance IRP learning and inform IRP implementation through the testing of new technologies, approaches or practices. This can include pilots, but may also cover other initiatives such as field trials or proofs of concept. The proposed flexibility for innovation-related IRP proposals could support Enbridge Gas in gaining a better understanding of the potential of IRP and the role it can play over the longer term in addressing Enbridge Gas's system needs.

Under the current IRP Framework, innovation-related proposals/pilots have identical OEB approval requirements to IRP Plans that address an identified near-term system need, with both requiring a project-specific approval from the OEB. Under the updated IRP Framework, OEB staff proposes a distinct approach to regulatory oversight for these proposals. Section 6.3.2 outlines four options for oversight mechanisms. One potential mechanism is for innovation-related proposals to be reviewed at a high level as part of the IRP Implementation Plan proceeding, with the possibility that the OEB's determination in this proceeding could also potentially establish requirements for the IRP Working Group to provide further review of design and implementation of approved innovation-related proposals, without the need for additional adjudicative review. This would enable Enbridge Gas to more nimbly refine and implement innovation-related proposals.

OEB staff also proposes five guiding considerations (potential to address system needs, risk and oversight, evaluation and scalability, alternative funding and knowledge sharing) that Enbridge Gas should address when developing innovation-related proposals.

## Topic 3: Electrification as an IRP Alternative

Electrification of energy needs (e.g., using an electric heat pump instead of a natural gas furnace to provide space heating) has the potential to reduce natural gas peak demand and thereby address natural gas system needs and avoid or defer natural gas infrastructure projects. The OEB concluded that as part of the first-generation IRP Framework, it was not appropriate to provide funding to Enbridge Gas for electrification IRP Alternatives. The energy planning landscape has evolved since this time, with Enbridge Gas implementing limited electrification measures as part of its IRP pilots, and new expectations in the IEP to improve integration of natural gas and electricity planning.

OEB staff supports making electrification an eligible IRP Alternative in the updated IRP Framework, as one of the measures that could be used to avoid or defer an identified upstream natural gas system reinforcement project. OEB staff believes that this is consistent with the intent of the IEP and will provide more opportunities to enable fuel switching across energy sources when it is cost-effective.

Any consideration of electrification as an IRP Alternative to connecting new customers would be limited to voluntary measures to preserve customer choice.

For IRP Plans that include electrification measures, OEB staff proposes that Enbridge Gas would be required to consult with impacted upstream providers (including electricity distributor(s) and the Independent Electricity System Operator) as to whether electricity system upgrades would be required to accommodate the increased electrical load. Enbridge Gas would take this information into consideration (including the estimated costs of any electricity system upgrades) in determining whether the electrification IRP Alternative remains the preferred option to address a system need.

OEB staff also proposes that the updated IRP Framework should not explicitly exclude other potential non-gas IRP Alternatives, in particular district energy, to make it possible for Enbridge Gas to bring forward a proposal for OEB consideration if it identifies a promising IRP opportunity.

## Topic 4: Other opportunities to improve the effectiveness and efficiency of the IRP Framework

OEB staff has identified three additional areas where there may be opportunities to improve the effectiveness and efficiency of the IRP Framework:

1. Consider increasing the cost threshold for when approval of an IRP Plan to address a system need is required. This would be consistent with the general intent of a recent change to Leave to Construct approval requirements and could reduce regulatory costs and expedite timelines for IRP Plans. This would also ensure that IRP solutions do not face more stringent approval requirements than pipeline projects. However, a consideration is that if an IRP Plan falls below the cost threshold for which OEB approval is required, there is no proceeding for the OEB to assess any concerns regarding potential impacts on Aboriginal or treaty rights.
2. Consider making detailed technical evaluation of IRP Alternatives for growth projects optional (at Enbridge Gas's discretion), for projects below a defined cost threshold. This could improve efficiency and enable Enbridge Gas to focus its IRP resources on higher-value projects where there is a greater likelihood of IRP implementation.
3. For the economic evaluation test (three-phase Discounted Cash Flow-plus test) used to assess the cost-effectiveness of IRP Alternatives relative to facility projects, consider adjusting the importance placed on rate impacts relative to other streams of costs and benefits. The three phases of the Discounted Cash Flow-plus test consider rate impact (phase one), incremental benefits and costs to participating customers (phase two) and incremental societal benefits and costs (phase three). The current IRP Framework places primary importance on phase one results, which makes it very unlikely that Enbridge Gas will select an energy efficiency IRP Alternative as the most cost-effective option, as its major benefit stream (savings in customer commodity/fuel costs) is excluded from this phase of the test.

   An alternative approach to making a determination on this issue within this proceeding would be to defer consideration of this issue to a subsequent adjudicative review of the enhanced Discounted Cash Flow-plus test.

# 1. IRP FRAMEWORK REVIEW CONSULTATION

## 1.1 Consultation Background

On July 22, 2021, the OEB issued a Decision and Order (EB-2020-0091) that established an Integrated Resource Planning (IRP) Framework that provides direction to Enbridge Gas as it considers IRP to meet its system needs.

As defined in the IRP Framework, IRP 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.

Facility Alternatives refer to traditional infrastructure solutions such as pipelines, while IRP Alternatives include demand-side solutions such as energy efficiency or supply-side solutions such as compressed natural gas. In other jurisdictions, the term "non-pipes alternatives" (NPA) is often used and is essentially synonymous with IRP Alternatives.

The 2021 IRP Decision and Order noted the IRP Framework was a first-generation Framework, and included the OEB's expectation that enhancements and improvements would be made in the future on the basis of the experience gained in Ontario from pilot projects and other IRP activities, drawing on successes achieved in other jurisdictions, and future policy direction.

In the years since the IRP Decision and Order, Enbridge Gas has taken steps to implement the OEB's expectations for IRP. To date this has resulted in one IRP project that addresses a system need and avoids capital spending. Concerns about Enbridge Gas's progress implementing IRP have been raised by parties in OEB adjudicative proceedings.

On March 27, 2025, the OEB announced that it was launching a consultation to support a review and evaluation of the IRP Framework. The OEB indicated that the review would be informed by challenges and progress in implementing the IRP Framework, an assessment of the impacts to date (including benefits to ratepayers), the IRP Pilot Project application (EB-2022-0335), and IRP-related evidence and submissions received during other proceedings.

The OEB indicated that the first step in the consultation would be an OEB staff report (this document) assessing progress implementing the IRP Framework and proposing updates to the IRP Framework.

## 1.2 Consultation Scope

The consultation announcement noted that the OEB intends to consider several key items. These topics are listed below and addressed in the identified chapters of the discussion paper:

- How the IRP Framework would be best constituted to allow for broad, flexible implementation that can adapt at a pace that supports innovation while providing regulatory certainty (chapter 5).
- The OEB's expectations and approach to oversight of innovation-related IRP proposals (chapter 6).
- Expectations for natural gas distributors regarding electrification as an Alternative, including how electricity availability issues should be considered if electrification is being proposed as an IRP Alternative (chapter 7).
- Opportunities to improve the effectiveness and efficiency of the Framework (chapter 8).

The discussion paper was also informed by a jurisdictional scan of system pruning activities and non-pipes alternatives programs, and discussions with the IRP Working Group, summarized in appendices B and C, respectively.

## 1.3 Request for Stakeholder Comments and Next Steps

OEB staff is seeking stakeholder input on specific questions, which are divided by topic and included at the end of the relevant chapters. A list of all questions is provided in appendix A.

As discussed in chapter 5, OEB staff also seeks stakeholder input on the preferred procedural approach to updating the IRP Framework, and whether an updated IRP Framework should be specific to Enbridge Gas, or applicable to all rate-regulated natural gas distributors.

Stakeholders are invited to participate in a virtual stakeholder meeting on **October 22, 2025** and subsequently submit comments by **November 19, 2025** that address the specific questions posed in the discussion paper or provide additional suggestions regarding the IRP Framework.

The OEB will consider stakeholder comments and subsequently determine next steps in the IRP Framework review.

# 2. OVERVIEW OF CURRENT IRP FRAMEWORK

## 2.1 Definitions

Table 1 describes the key defined terms in the existing IRP Framework.

**Table 1. Key Terms in IRP Framework**

| Term | Definition |
|---|---|
| Integrated Resource Planning (IRP) | 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 the IRP Framework, the term is synonymous with a traditional or conventional facility project. This would typically include a hydrocarbon line (as defined in the *Ontario Energy Board Act, 1998*) 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 IRP Alternatives and not Facility Alternatives. |
| IRP Alternative | 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. IRP Alternatives determined by Enbridge Gas to be the preferred solution to meet the system need (alone, in combination with other IRP Alternatives, or in combination with a Facility Alternative) would likely be brought forward for approval from the OEB through an IRP Plan. |
| IRP Plan[4] | A plan filed by Enbridge Gas for OEB approval in response to a specific system need, that includes one or more IRP Alternatives. |

[4] As discussed in chapter 5, OEB staff proposes a new requirement in the evolved IRP Framework: an IRP Implementation Plan (a term not defined in the current IRP Framework). As proposed, the IRP Implementation Plan would be a higher-level, system-wide plan for Enbridge Gas's IRP activities, and should not be confused with an IRP Plan, which is a targeted plan to address a specific system need.

## 2.2 Key Elements of IRP Framework

Key elements of the existing IRP Framework are outlined below.

- **Guiding principles:** The IRP Framework includes guiding principles on reliability and safety, cost-effectiveness, public policy, optimized scoping and risk management.
- **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. This includes demand-side programming, such as geotargeted energy efficiency programs, demand response programs and interruptible rates. Demand-side IRP Alternatives are expected to target specific constrained areas and encourage customers to reduce peak consumption. Supply-side IRP Alternatives could include compressed natural gas, renewable natural gas, or market-based supply-side alternatives. As part of the first-generation IRP Framework, the OEB determined that it is not appropriate to provide funding to Enbridge Gas for electricity IRP Alternatives. The eligibility of electrification in an evolved IRP Framework is discussed in chapter 7.
- **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. This process and its results to date are discussed in section 3.2.
- **Stakeholder outreach and engagement process:** The IRP Framework defines a three-component stakeholder engagement process to provide input into Enbridge Gas's IRP activities and establishes an IRP Working Group to provide 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.
- **Indigenous engagement and consultation:** The IRP Framework describes the OEB's expectations as to how Enbridge Gas will engage Indigenous groups and conduct consultation with respect to any potential impacts to Aboriginal or treaty rights in relation to proposed IRP Plans.
- **Cost recovery, accounting treatment and deferral accounts:** The IRP Framework describes which IRP costs will be considered eligible for inclusion in rate base or treated as operating expenses, and establishes two deferral accounts to track incremental IRP-related costs not included in base rates, with an expectation that disposition of these account balances will be considered as part of Enbridge Gas's annual Non-Commodity Deferral Account Clearance and Earnings Sharing Mechanism application.

- **IRP Plan applications:** The IRP Framework established a new approval process for IRP Plans to address a system need, with information requirements similar to what is found in a Leave to Construct application.
- **Monitoring and reporting:** The IRP Framework required Enbridge Gas to file an annual IRP report for informational purposes.
- **IRP pilot projects:** The IRP Framework established an expectation that Enbridge Gas would develop and implement two IRP pilot projects, to understand and evaluate how IRP can be implemented to avoid, delay or reduce facility projects.

# 3. IRP PROGRESS AND IMPACTS TO DATE

## 3.1 Achievements and Opportunities

Since the establishment of the IRP Framework, Enbridge Gas has made concerted efforts to meet the OEB's expectations in the Framework.

Notable achievements include the following:[5]

- **Incorporating consideration of the potential for IRP Alternatives to address system needs into Enbridge Gas's AMP process:** This includes reporting by Enbridge Gas on the status and outcomes of IRP consideration on a project-by-project basis.[6] This is discussed in more detail later in this chapter.
- **Design, approval and implementation of Southern Lake Huron pilot:** Enbridge Gas applied for and received OEB approval to implement an IRP pilot in the Southern Lake Huron region. This pilot was developed with input from the IRP Working Group. The primary objectives of the Southern Lake Huron pilot are to develop an understanding of how demand-side IRP Alternatives, including enhanced targeted energy efficiency (ETEE) and demand response, impact peak hour flow/demand and to develop an understanding of how to design, deploy, and evaluate ETEE and residential demand response programs. The OEB initiated a notice of review of certain aspects of the decision on the IRP pilot; however, Enbridge Gas is moving forward with implementation of most aspects of the pilot as approved by the OEB, except for those expressly at issue in the OEB's notice of review.
- **Design of system pruning pilot:** Enbridge Gas has developed a detailed approach for an additional pilot focused on system pruning (proactive decommissioning of a portion of the natural gas system that is no longer required to serve the needs of energy users), in consultation with the IRP Working Group. Pilot implementation is expected to begin by the end of Q1 2026.
- **Actions to increase potential customer adoption of interruptible rates:** These actions include new authority (approved by the OEB) for Enbridge Gas to implement negotiated interruptible rates with customers as part of an IRP Plan,

[5] Additional detail on Enbridge Gas's IRP activities to date can be found in its report on the status of IRP directions (filed as EB-2025-0064 Phase 3 Application and Evidence, Exhibit 1, Tab 13, Schedule 5), and in Enbridge Gas's 2024 IRP Annual Report, filed as part of IRRs in this proceeding (Exhibit I.1.13-ED-4, Attachment 1)

[6] The most recent version of this assessment can be found in Appendix B of Enbridge Gas's 2025-2034 Asset Management Plan.

and an approach to asking customers about the use of interruptible rates as part of its Expression of Interest/Reverse Open Season process that is used in the assessment of need and alternatives in demand-driven Leave to Construct projects. Enbridge Gas also completed an Interruptible Rates Study and has requested approval for rate design changes that would significantly increase the price spread between firm and interruptible rates.[7]

By reducing the firm peak demand needs of customers that Enbridge Gas is obligated to serve, the use of interruptible rates can potentially avoid or defer the need for system reinforcement projects. However, to date, these initiatives have not resulted in increased use of interruptible rates by customers.

- **Preliminary approach to stranded asset risk:** Enbridge Gas developed a preliminary approach to assessing stranded asset risk (the risk of assets becoming unused before being fully depreciated) for traditional infrastructure investments as part of its application for the St. Laurent pipeline replacement project.[8] This entails assessing the possible useful life of the asset under various electrification scenarios, and taking this into account in the economic assessment of project alternatives.

With the exception of the small East Kingston Creekford Road project (where Enbridge Gas first contracted for a compressed natural gas solution and subsequently obtained a reduction in contract demand from a customer, thereby reducing peak demand in order to avoid a system reinforcement project), Enbridge Gas has not implemented any IRP projects that addressed a system need and thereby avoided or deferred infrastructure spending.[9] This has been identified as a concern by some stakeholders, including IRP Working Group members, and is explored further in section 3.2.

Enbridge Gas has incurred incremental efforts and costs to implement the IRP Framework. In 2023, incremental costs of $3.1 million were requested for disposition.[10]. A small amount of 2023 IRP spending ($0.3 million) was related to the East Kingston Creekford Road project, but most costs ($2.7 million) are for 16 full-time equivalent staff who perform IRP work that is incremental to what was performed by Enbridge Gas prior

[7] EB-2025-0064 Phase 3 Application and Evidence, Tab 4, Schedule 7

[8] EB-2024-0200, Exhibit B, Tab 3, Schedule 1, plus attachments

[9] The IRP pilot in the Southern Lake Huron region does not address a system need in Enbridge Gas's AMP, so does not avoid or defer infrastructure spending.

[10] EB-2024-0125, Exhibit C, Tab 1, Table 1. This figure does not include any costs related to the Southern Lake Huron pilot, where disposition will be requested at a later date.

to the issuance of the IRP Framework.[11] Incremental IRP-related costs also arise from the IRP Working Group, such as cost awards paid to non-utility members. The limited pipeline infrastructure avoided/deferred and limited progress in piloting IRP relative to the investment to-date in IRP indicates that there may be an opportunity to improve the value-to-investment ratio for IRP activities going forward.

There have also been delays experienced with IRP implementation:

- **Delay in finalizing economic evaluation methodology (Discounted Cash Flow-plus test).** The IRP Decision and Order required Enbridge Gas, in consultation with the IRP Working Group, to study improvements to the Discounted Cash Flow-plus (DCF+) test (used to assess the cost-effectiveness of IRP Alternatives relative to facility alternatives).

  Enbridge Gas was directed to file an enhanced DCF+ test for approval as part of the first non-pilot IRP Plan. The IRP Working Group has held extensive discussion on the DCF+ test, including a detailed report released in 2023, but has been unable to reach consensus between Enbridge Gas and non-utility members on some aspects of the test. As Enbridge Gas has yet to file the first non-pilot IRP Plan and there is no deadline by which Enbridge Gas must file an enhanced DCF+ test, no approved methodology is in place. The DCF+ test is discussed in more detail in section 8.3.

- **Delays implementing pilot projects**. The IRP Decision and Order established an expectation that Enbridge Gas would select and deploy two IRP pilot projects by the end of 2022. As of September 2025, the OEB has approved one pilot with some aspects of the pilot still subject to a notice of review. Chapter 6 discusses an updated approach to oversight of innovation-related IRP proposals.

An opportunity to address these challenges through a proposed new requirement for Enbridge Gas to file an IRP Implementation Plan is discussed in chapter 5.

[11] From 2025 onwards, provision for these costs is incorporated into base rates, although Enbridge Gas will still have the ability to record costs in the IRP costs deferral accounts that are incremental to those included in base rates.

## 3.2 IRP Assessment Process and Results

This section provides an overview of Enbridge Gas's implementation of the IRP Assessment Process described in the IRP Framework, and its results to date when it has been applied to consideration of alternatives in Leave to Construct applications and to projects in Enbridge Gas's AMP. This analysis assists in understanding some of the factors as to why Enbridge Gas has, to date, implemented only one IRP project to address a system need or avoid/defer infrastructure spending.

Enbridge Gas has commented as part of the most recent IRP Working Group report that the lack of success for IRP Alternatives in the IRP Assessment Process to date is an analytical finding, not a failure, as the goal of the IRP Framework is not to maximize the number of IRP Alternatives implemented, but rather to ensure the most appropriate solution to a given system need is identified based on the defined criteria and policy context in Ontario.[12]

OEB staff agrees with Enbridge Gas's perspective on the goal of the IRP Framework. OEB staff further agrees that the lack of success for IRP Alternatives in the IRP Assessment Process to date could be an analytical finding, not a failure. However, as discussed in the subsections below, it is important to ensure that the outcomes of Enbridge Gas's implementation of the IRP Assessment Process are not a result of Enbridge Gas disadvantaging IRP Alternatives. Enbridge Gas's approach to evaluating IRP alternatives is generally outlined in supporting policy and guidance documents that Enbridge Gas has developed to assist in implementing the IRP Framework. As noted in chapter 5, OEB staff proposes that these supporting policies and guidance documents could be considered by the OEB in an adjudicative review of an Enbridge Gas IRP Implementation Plan, if compatible with an updated IRP Framework.

OEB staff also notes that several OEB staff proposals for changes to the IRP Framework, described in later chapters, may increase the likelihood of IRP Alternatives being selected as the preferred option to address a system need. Specific OEB staff proposals that may increase the likelihood of IRP Alternatives being selected as the preferred option to address a system need are making electrification an eligible IRP Alternative (chapter 7) and reconsidering the OEB's relative emphasis on the different phases of the DCF+ economic evaluation (section 8.3).

[12] Review of Enbridge Gas Inc. 2024 Integrated Resource Planning (IRP) Annual Report and Update on IRP Working Group Activities, p. 17 (Comments of Enbridge Gas IRP Working Group Members)

### 3.2.1 IRP Assessment Process

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

1. **Identification of Constraints:** Potential system needs/constraints are identified up to ten years in the future and described in annual updates to the AMP, to allow time for a detailed examination of IRP Alternatives.
2. **Binary Screening Criteria:** Screening criteria are established to exclude some system needs from 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 system need. The IRP Framework includes the following criteria to exclude system needs from further IRP consideration:
    - Emergent safety issues
    - System needs that must be met in under three years
    - Customer-specific builds where the customer requests a facility project and fully pays for the incremental infrastructure costs
    - Community expansion and economic development projects driven by government legislation or policy with related funding explicitly aimed at delivering natural gas into communities[13]
    - Pipeline replacement or relocation projects costing less than the minimum project cost that would necessitate a Leave to Construct approval.
3. **Two-Stage Evaluation Process:** For system needs progressing past the initial IRP binary screening, Enbridge Gas determines whether to proceed with an IRP Plan through a two-stage evaluation. First, Enbridge Gas determines whether potential IRP Alternatives could meet the identified constraint/need through a ***technical evaluation***. If it can, then Enbridge Gas compares one or more IRP Plans to the baseline Facility Alternative, using an ***economic evaluation*** (DCF+ test) to determine the optimum solution to meet the system need.
4. **Periodic Review:** Material changes may occur that could impact Enbridge Gas's determination as to how best to meet a system need.

[13] Projects supported by the Natural Gas Expansion Program

As Enbridge Gas has worked through applying the IRP Assessment Process to projects in its AMP, it has refined its process, as documented in its *IRP Assessment Screening and Evaluation Guidelines*.[14] These guidelines note several additional details that are not specified in the IRP Framework:

- Spending on the customer connections asset class (distribution mains, services and regulating equipment to serve new customers) is screened out at the binary screening stage. Enbridge Gas determined that implementing an IRP Alternative could not reduce the size of the assets, as these cannot be further downsized, and that there are no non-gas IRP Alternatives available within the current IRP Framework that can be offered to avoid the customer connection service being requested.
- Enbridge Gas identifies additional categories of investments that do not have a technically feasible IRP Alternative, but are not covered by the binary screening criteria in the IRP Framework. Enbridge Gas has added a new technical screening stage which eliminates projects in the categories from further consideration of IRP Alternatives without requiring detailed technical evaluation.

### 3.2.2 IRP Assessment Results

The results of Enbridge Gas's IRP assessments and consideration of IRP Alternatives for system needs are provided to the OEB in Leave to Construct proceedings (for projects that trigger the need for a Leave to Construct approval), and on an informational basis in annual AMP updates (for all projects in the AMP).

**Leave to Construct proceedings:**

Enbridge Gas's IRP assessment results for Leave to Construct projects, none of which have resulted in an IRP Plan being selected as a preferred option, are summarized in Enbridge Gas's 2024 IRP Annual Report.[15] Consideration of IRP Alternatives for most of these projects was ruled out due to the binary screening criteria for customer-specific builds, timing, or community expansion & economic development. Two major pipeline projects, the Panhandle Regional Expansion Project[16] and the St. Laurent Pipeline Replacement Project[17], passed through the binary screening stage but later failed at the technical evaluation stage, and are discussed further below.

---

[14] Filed as Appendix F in the Enbridge Gas 2024 IRP Annual Report

[15] Appendix D

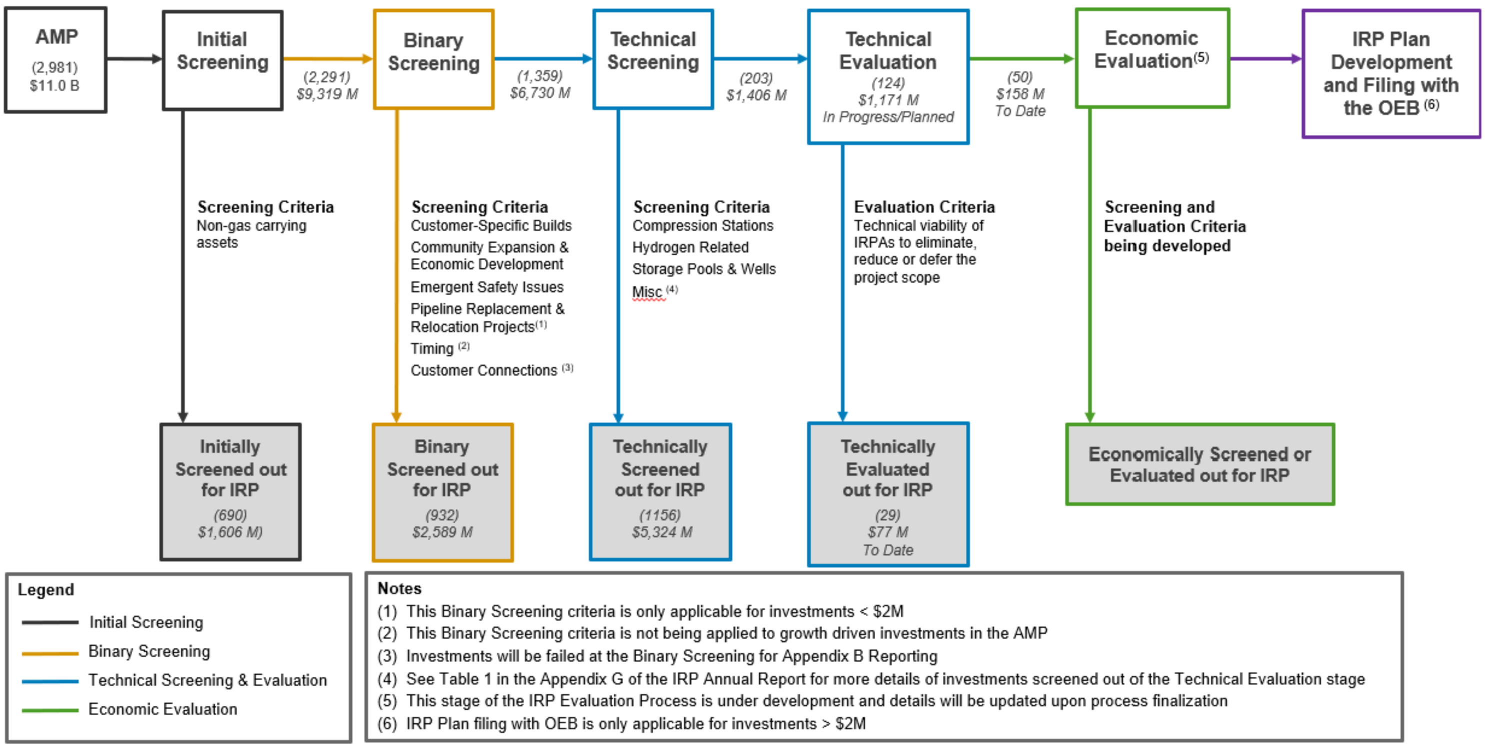
[16] EB-2022-0157

[17] EB-2024-0200

### Projects in 2025-2034 AMP:

The results of Enbridge Gas's application of its *IRP Assessment Screening and Evaluation Guidelines* to its 2025-2034 AMP are shown below in Figure 1.[18]

**Figure 1. IRP Evaluation Process and Results for System Needs in 2025-2034 Asset Management Plan[19]**




### Assessment of system needs:

The 2025-2034 AMP outlines all system needs that Enbridge Gas has identified will need to be addressed during this 10-year period. The system needs in the AMP, and the analyses of the IRP Assessment Process to meet these needs, are updated on an annual basis. A learning from this process has been that system needs in the AMP, and their associated timing, are very sensitive to Enbridge Gas's demand forecasting assumptions. To date, year-to-year changes to the demand forecast used for the AMP

---

[18] Additional details are provided in Appendix C of the Enbridge Gas 2024 IRP Annual Report (Tables 1 to 6).

[19] Enbridge Gas 2024 IRP Annual Report, Figure 3.2. The numbers shown next to each stage identify the number of projects, and the associated capital spending (in $ millions) for the baseline facility solution.

have mostly been downward, thereby reducing the number and cost of growth-related system reinforcement projects in the AMP.[20] These are the types of projects most suitable for IRP consideration, so there have been fewer opportunities for potential IRP Plans. For example, all three of the projects which were initially identified as high priority candidates for addressing through IRP pilots or IRP Plans (Parry Sound, Southern Lake Huron, Owen Sound) had their status adjusted (pushed back in time or removed from the 10-year AMP) due to changes to the demand forecast.

If the demand forecast changes upward, the corollary is that projects may move back into the AMP. This may have implications for the three-year timing binary screening criterion in the IRP Framework, The IRP Framework notes that once a 10-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, this implicitly assumes a relatively stable year-year to year AMP, where the existence, magnitude and timing of a system need can be accurately identified well in advance (allowing for adequate lead time to assess and implement IRP Alternatives). When this turns out not to be the case, the potential for IRP Alternatives, and in particular, demand-side alternatives such as energy efficiency, to address the system need are limited, as discussed further in the Posterity model of energy efficiency potential later in this section. Several IRP Working Group members noted that the sensitivity of system needs to the demand forecast also calls into question whether Enbridge Gas's traditional facility investments are always warranted, and suggested that a retroactive evaluation of facility investments (e.g., did the growth that was forecast materialize in terms of timing and demand? How sensitive were the conclusions for facilities vs. IRP Alternatives to capital costs and growth?) could inform future planning and may help place IRP Alternatives and facility alternatives on a level playing field.[21]

Another approach to address the issue of sensitivity of system needs to the demand forecast, suggested by an IRP Working Group member, is to place more of a focus within Enbridge Gas's Demand-Side Management (DSM) Framework on peak demand reduction (in addition to overall natural gas savings). This would entail ascribing some system-wide value to infrastructure deferral/avoidance from peak demand reduction, without needing to know which specific projects may be avoided or deferred. If adopted, this would likely increase the value of (and therefore investment in) DSM programs that focus on peak demand reduction, which could complement the project-by-project approach to pursuing peak demand reduction used in the IRP Framework.

---

[20] See Enbridge Gas materials provided for IRP Working Group meetings 34, 35 and 37.

[21] Review of Enbridge Gas Inc. 2024 Integrated Resource Planning (IRP) Annual Report and Update on IRP Working Group Activities, p. 12

### Binary and technical screening stages:

$1.4 billion of projects (from the $11.0 billion of projects in the 2025-2034 AMP) pass through the screening stages to reach the technical evaluation stage.

**Table 2. Projects in 2025-2034 AMP Eliminated From IRP Consideration Through Binary and Technical Screening[22]**

| Screening Criterion | 2025-2034 Forecast Spending | Number of Projects |
|---|---|---|
| Non-gas carrying assets | $1,606.2 million | 690 |
| **Binary screening criteria in IRP Framework** | | |
| Customer-specific builds | $219.5 million | 3 |
| Pipeline replacement/relocation (below dollar threshold) | $469.9 million | 865 |
| Community expansion and economic development | $3.9 million[23] | 2 |
| Emergent safety | $6.1 million | 3 |
| **All binary screening criteria in IRP Framework[24]** | **$699.4 million** | **873** |
| Customer connections | $1,889.7 million | 59 |
| Other asset classes excluded through technical screening | $5,323.8 million | 1156 |
| **All screening criteria** | **$9,519.1 million** | **2778** |

As shown in Table 2, the additional screening criteria excluding customer connections and other asset classes excluded through technical screening result in a large portion of AMP spending being removed from further IRP consideration, in addition to the projects removed from consideration due to the IRP binary screening criteria defined in the IRP Framework. OEB staff believe that these exclusions from further IRP consideration are generally reasonable; however, the large dollar value associated with these exclusions for asset classes not explicitly screened out in the IRP Framework is one reason why OEB staff are recommending that the *IRP Assessment Screening and Evaluation*

---

[22] Adapted with modification from Tables 1,2,3 in Appendix C of Enbridge Gas's 2024 IRP Annual Report

[23] This will underestimate the cost and number of projects excluded from IRP consideration due to this criterion, because Enbridge Gas typically does not list community expansion projects in the AMP, as they are not part of base rates.

[24] Enbridge Gas did not remove any projects in the 2025-2034 AMP from further IRP consideration due to the fifth binary screening criterion (timing – need must be met in under three years).

*Guidelines* should be considered in adjudicative review (as part of Enbridge Gas's IRP Implementation Plan, if OEB staff's proposal is adopted, as described in chapter 5).

**Technical evaluation stage:**

If a project has reached the technical evaluation stage ($1.4 billion of projects in the 2025-2034 AMP), this means that Enbridge Gas made a preliminary determination that there is potential for an IRP Alternative to defer, reduce or eliminate project scope. A small amount of project spending in this category ($77 million) then failed the technical evaluation, even if the project scope could potentially be changed through an IRP Alternative.[25] However, the majority of project spending reaching the technical evaluation stage either still has technical evaluation pending ($1.2 billion) or has initially passed the technical evaluation and proceeded to economic evaluation ($158 million).

The reference to "initially passing" the technical evaluation means that, for these projects, Enbridge Gas has confirmed that there is potential for an IRP Alternative to defer, reduce or eliminate project scope and that it is worthwhile to conduct an economic evaluation, but Enbridge Gas has not completed a full technical evaluation (including modelling of energy efficiency potential) to determine whether the amount of peak demand reduction/supply that would be needed from the IRP Alternative to address the system need is achievable in practice. Enbridge Gas is taking this iterative approach (which OEB staff supports) of proceeding to an economic evaluation without full modelling of technical potential of IRP Alternatives to test more projects at the economic evaluation stage and obtain learnings about the economic evaluation test.

However, it is an important distinction because in two key Leave to Construct proceedings (the Panhandle Regional Expansion Project and the St. Laurent Pipeline Replacement Project) since the IRP Framework was established, Enbridge Gas ultimately failed IRP Alternatives at the technical evaluation stage based on an inability to achieve the required peak demand reduction to address the system need. This suggests that many projects in the 2025-2034 AMP with the status of technical evaluation pending or proceeded to economic evaluation could still eventually fail a more comprehensive technical evaluation.

In both the Panhandle Regional Expansion Project and the St. Laurent Pipeline Replacement Project proceedings, Enbridge Gas concluded that ETEE was not a technically viable alternative as it could not achieve the required peak demand reduction to avoid the need for a pipeline (or in the case of the St. Laurent Pipeline Replacement

---

[25] Reasons for this determination include that downsizing a pipeline project would introduce a bottleneck in a trunk main, which Enbridge Gas has indicated is not desirable from a network operations perspective.

Project, to downsize the replacement pipeline). Enbridge Gas's conclusions were based on evaluations of ETEE potential from the Posterity Group. Some concerns around the Posterity modelling of ETEE potential were raised in these proceedings.[26]

- The Posterity model assumes there is no incremental peak demand reduction potential from contract customers, only from general service customers. Enbridge Gas's rationale for this approach is that potential ETEE actions (as well as the possible use of interruptible rates) is implicitly taken into account by the contracted demand volumes for firm service from these customers, and that no incremental peak demand reduction is achievable.
- The Posterity model assumes that it takes several decades to achieve the full ETEE potential from general service customers, as ETEE opportunities are limited by stock turnover and the useful lives of energy-using products. A corollary to this assumption is that only a small amount of ETEE potential can typically be achieved within the few years between the time Enbridge Gas conducts a technical potential evaluation and the time that a system need must be addressed. OEB staff and some parties suggested that Enbridge Gas may need to implement IRP Alternatives at an earlier stage, even if there is some uncertainty as to when and whether the need will materialize. This would require Enbridge Gas to consider the trade-offs as to the appropriate time to act to address an identified system need (e.g., delay allows system need to be specified with more certainty but may rule out IRP Alternatives).

Enbridge Gas continues to work with Posterity Group on updating the IRP model for assessing ETEE potential. Because Enbridge Gas's approach to assessing IRP potential has significant implications for whether IRP Alternatives pass the technical evaluation stage, OEB staff recommends that the approach to assessing technical potential of IRP Alternatives should also be considered in adjudicative review as part of Enbridge Gas's IRP Implementation Plan.

**Economic evaluation stage:**

At the time of the 2025-2034 AMP, no economic evaluations of projects passing the technical evaluation had been completed. Enbridge Gas has subsequently (at the time of writing), completed economic evaluations using its enhanced DCF+ methodology (which has not been explicitly approved by the OEB) for seven growth-related projects.[27] Based on the economic evaluation results, Enbridge Gas has already proceeded with implementation of a Facility Alternative (traditional infrastructure) for

[26] See section 3.2 of EB-2022-0157 Decision and Order, May 14, 2024 for additional detail.

[27] See Enbridge Gas slides from IRP Working Group meeting 57, July 30, 2025

three projects where the Facility Alternative was the most cost-effective option. For three additional projects, the economic evaluation found that a Facility Alternative was the most cost-effective option, while for one project, a supply-side IRP Alternative (compressed natural gas) was the most cost-effective. Demand-side IRP Alternatives have not been cost-effective in any of these economic evaluations. While not conclusive, these results suggest that IRP Alternatives may not be cost-effective for many system needs, at least under the DCF+ as currently applied by Enbridge Gas. The elimination of the Federal Carbon Charge (discussed in chapter 4) is also a contributor to reduced cost-effectiveness results for demand-side IRP Alternatives.

# 4. EVOLVING THE IRP FRAMEWORK

## 4.1 Drivers for IRP

As noted earlier, the IRP Framework defines IRP as 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.

The expectation in the IRP Framework that Enbridge Gas will consider IRP Alternatives to identify the option in the best interest of customers is currently parallelled on the electricity side through the OEB's Non-Wires Solutions Guidelines for Electricity Distributors, although the details of the policies differ.

The OEB's expectations regarding consideration of non-infrastructure alternatives take account of the potential that non-infrastructure alternatives have to compete with traditional infrastructure solutions. In this regard, several factors specific to the natural gas sector contributed to the establishment and form of the original IRP Framework:

- Enbridge Gas had extensive experience in delivering natural gas energy efficiency programs, yet (at the time of the original IRP Decision and Order) had not delivered programs specifically targeting peak demand reduction and infrastructure avoidance/deferral. In contrast, the Independent Electricity System Operator (IESO) had long targeted peak demand reduction as a primary goal for its electricity energy efficiency programs. There was an assumption that there might be untapped opportunities for Enbridge Gas to build on its expertise with energy efficiency programs to pursue and deliver targeted peak demand reduction.
- IRP Alternatives which reduce natural gas consumption (such as energy efficiency programs) also provide large climate mitigation benefits in the form of greenhouse gas emissions reductions. At the time of the IRP Decision and Order, the Federal Carbon Charge was scheduled to rise (increasing at $15 per tonne per year through 2030), therefore, energy efficiency IRP Alternatives would become increasingly more cost-effective to customers relative to infrastructure solutions.

- Some stakeholders viewed the possibility of new infrastructure being stranded due to the transition towards electrification as a risk for the natural gas sector.[28] IRP Alternatives may have the potential to meet system needs with reduced capital investment, thereby reducing stranded asset risk.

OEB staff notes that the policy context for the last two points has evolved since the issuance of the original IRP Framework in 2021:

- The Federal Carbon Charge has now been set to zero, effective April 1, 2025.[29] As the Federal Carbon Charge had become a significant component of customer natural gas bills, its removal reduces the cost-effectiveness of IRP Alternatives that reduce natural gas consumption.

  Enbridge Gas remains subject to the provincial Emissions Performance Standards for large industrial emitters. However, only a small portion of natural gas emissions (those associated with Enbridge Gas's upstream transmission infrastructure, as opposed to end-use emissions from customers), are currently subject to the Emissions Performance Standards, which means that emissions reductions from IRP Alternatives now have almost no impact on customer bills.

- Ontario's Natural Gas Policy Statement in the IEP indicates that "as part of a gradual transition to a more diverse energy system, Ontario will continue to support the important role of natural gas in Ontario's energy system and economy while pursuing options to lower costs and reduce emissions through energy efficiency, electrification, clean fuels (e.g., renewable natural gas, low-carbon hydrogen) and carbon capture and storage" and that "there is a need for an economically viable natural gas network – as the province builds a more diverse energy system – to attract industrial investment, to drive economic growth, to maintain customer choice and ensure overall energy system resiliency, reliability and affordability."[30]

IRP Working Group members agree that policy considerations have a material impact on whether IRP projects will be implemented, but do not necessarily agree on the approach that should be taken. For example, one Working Group member recommended that support for the consistent and long-term valuation of greenhouse gas emissions benefits and consideration of stranded asset risks should be part of the

---

[28] This is not the case for the electricity sector, where forecasts have projected significant growth in electricity demand, which continues to be the case. For example, the IESO's 2025 Annual Planning Outlook forecasts a 75% growth in electricity demand by 2050.

[29] *Removing the consumer carbon price, effective April 1, 2025*, Department of Finance Canada

[30] Chapter 5 (p. 96) in Ontario's Integrated Energy Plan.

updated IRP Framework, considering the climate crisis and the potential speed of the energy transition, while another member simply noted that there is no clear reason to implement IRP Alternatives in the current public policy environment, so it should not be a surprise that they are not progressing.[31]

## 4.2 Strategic Approach to an Evolved IRP Framework

The policy factors identified above suggest that, at least, in the near-term, there may be fewer opportunities for cost-effective deployment of IRP Alternatives than may have been anticipated when the IRP Framework was originally issued.

Nevertheless, OEB staff believe that continued investigation and consideration of IRP Alternatives in system planning is of value to natural gas customers (to ensure prudent investment decision-making) and is aligned with the IEP (discussed in more detail in the next section).

The OEB staff proposals described in subsequent chapters of this Discussion Paper would be an incremental evolution of the existing IRP Framework. These proposals seek to address the specific questions identified by the OEB in its announcement of the review of the IRP Framework, and to generally improve the effectiveness and efficiency of the IRP Framework. For example,

- Some of these proposals, if adopted, would enable Enbridge Gas to continue efforts to gain learnings on IRP, even where it is not the most cost-effective near-term approach to address system needs. This would better position natural gas distributors to deploy IRP at greater scale, should changes in the strategic context or policy environment make it prudent to do so.
- Other proposals, informed by learnings from the implementation-to-date of the current IRP framework, will ensure IRP-related regulatory obligation and processes remain reasonable and efficient.

If adopted, these proposals should continue to drive adoption of the most prudent infrastructure or IRP Alternative to meet a given system need, while improving the IRP value-to-investment ratio and positioning the natural gas sector to quickly and effectively adapt to various potential future scenarios.

[31] Review of Enbridge Gas Inc. 2024 Integrated Resource Planning (IRP) Annual Report and Update on IRP Working Group Activities, pp. 8-9

**Utility Incentives/Penalties:**

In addition to the policy factors identified above, OEB staff also notes that some stakeholders believe that a major reason why there has not been more progress in IRP implementation is that IRP is not aligned with the financial interests of Enbridge Gas and its shareholders. Possible remedies to address this concern are incentives to Enbridge Gas for pursuing IRP where appropriate, or penalties/consequences for not doing so. For example, one IRP Working Group member has suggested assigning the risk of losses from infrastructure assets that become stranded or underutilized to shareholders instead of ratepayers, suggesting that this would encourage Enbridge Gas to place greater emphasis on IRP and non-infrastructure solutions.[32]

OEB staff notes that the IRP Decision and Order concluded it was premature to develop an incentive mechanism as part of the first-generation IRP Framework. However a partial settlement in Enbridge Gas's recent rebasing application requires Enbridge Gas to file an IRP incentive mechanism for the OEB's consideration in the near future.[33]

Given this development, OEB staff recommends that the updated IRP Framework provide for the possibility of a shareholder incentive mechanism for IRP investments. However, the specifics of any incentive mechanism should be reviewed in the context of a specific utility application. For this reason, this discussion paper does not provide any additional proposals on this topic.

[32] May 27,2025 e-mail from Jay Shepherd (provided as follow-up to discussion at May 21, 2025 IRP Working Group meeting)

[33] EB-2024-0111, Partial Settlement Proposal, November 4, 2024. The language in the partial settlement proposal (which was subsequently approved by the OEB) requires Enbridge Gas to file the incentive mechanism proposal within a year of the filing of the original partial settlement proposal.

## 4.3 Alignment with Integrated Energy Plan

Ontario's IEP is focused on four principles:[34]

- **Affordability** means keeping energy costs low for families, businesses and industry.
- **Security** means having the supply, infrastructure and domestic capabilities to stay self-reliant and resilient, while keeping Ontario's power system secure.
- **Reliability** means building a system that works 24/7, in every season and every part of the province.
- **Clean energy** means attracting investment and building Ontario's economy while providing North America with a continental solution to reduce emissions.

While the IRP Framework predates the IEP, the IRP Framework's guiding principles align well with the core IEP principles, as the IRP Framework defines IRP as a planning strategy and process that considers Facility Alternatives and IRP Alternatives (including the interplay of these options) to identify and implement the alternative (or combination of alternatives) that is in the best interest of Enbridge Gas and its customers, taking into account cost-effectiveness, reliability and safety, and public policy, among other considerations.

Taken together, OEB staff's proposals are intended to make the IRP Framework more effective at delivering on this goal, while refining IRP-related regulatory processes and obligations to produce regulatory efficiencies.

Further, as shown in Table 3, the OEB staff proposal to make electrification an eligible IRP Alternative (chapter 7), would contribute to the IEP's priority of considering all fuels and technologies together in planning to deliver a range of energy system-wide benefits, including enabling fuel-switching when cost-effective and focusing on customer's total energy bills, instead of electricity and other fuel bills separately.[35]

---

[34] Ontario's Integrated Energy Plan, p.7

[35] Ontario's Integrated Energy Plan, pp. 119-120

**Table 3. Alignment between Integrated Energy Plan and Integrated Resource Planning Framework**

| IEP Principle | Existing IRP Framework Guiding Principles[36] | OEB Staff Proposals to Evolve the IRP Framework |
|---|---|---|
| Affordability | IRP Alternatives must be cost-effective (competitive) compared to Facility Alternatives and other IRP Alternatives, including taking into account impacts on Enbridge Gas customers. | For IRP Alternatives encompassing electrification, cost-effectiveness assessments would include consideration of electricity costs, as well as natural gas costs. |
| Security and Reliability | In considering IRP Alternatives 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. | Consideration of security and reliability would be expanded to encompass the electricity system. When considering electrification measures in IRP Plans, Enbridge Gas would be required to consult with the impacted distributor(s) and the IESO to identify potential impacts on the electricity system |
| Clean Energy | While not an explicit guiding principle in the IRP Framework, eligible IRP Alternatives are equal (e.g., compressed natural gas) or lower-emitting (e.g., energy efficiency, renewable natural gas) than conventional natural gas | Making electrification an eligible IRP Alternative would provide additional opportunities for implementation of lower-emission IRP Alternatives. |

Continued investigation and consideration of IRP Alternatives also aligns with the Natural Gas Policy Statement in the IEP that "as part of a gradual transition to a more diverse energy system, Ontario will continue to support the important role of natural gas in Ontario's energy system and economy while pursuing options to lower costs and reduce emissions through energy efficiency, electrification, clean fuels (e.g., renewable natural gas, low-carbon hydrogen) and carbon capture and storage."[37]

## 4.4 Discussion Questions

1. What implications does the current public policy environment have for an evolved IRP Framework and the OEB's IRP-related expectations of natural gas distributors?

[36] IRP Framework, s.3

[37] Chapter 5 (p. 96) in Ontario's Integrated Energy Plan.

# 5. FRAMEWORK REVIEW TOPIC 1: UPDATE AND OVERSIGHT OF IRP FRAMEWORK

*"How the IRP Framework would be best constituted to allow for broad, flexible implementation that can adapt at a pace that supports innovation while providing regulatory certainty."*

## 5.1 Requirements in IRP Framework

The existing IRP Framework was established through an adjudicated decision and order. The IRP Framework applies only to Enbridge Gas but notes that it should also be used as a resource to guide EPCOR Natural Gas Limited Partnership when it examines infrastructure investments and potential alternatives.

The IRP Framework notes an expectation that enhancements and improvements will be made in the future based on the experience gained in Ontario with pilot projects and other IRP activities, drawing on successes achieved in other jurisdictions and future policy direction. However, there is no specific process or timing established to review and update the IRP Framework, or a sunset date.

The IRP Framework also establishes mechanisms for oversight of and input into Enbridge Gas's implementation of the IRP Framework:

- **Annual reporting:** Enbridge Gas is required to file an annual IRP report. The IRP Framework provides additional details on the informational requirements for the annual IRP report. The annual IRP report is filed as part of Enbridge Gas's Non-Commodity Deferral Account Clearance and Earnings Sharing Mechanism application, which includes disposition of the costs recorded in the IRP Costs deferral accounts. The OEB does not approve the annual IRP report. Any decisions with respect to the annual IRP Report in the proceeding in which it is filed are related to findings on the disposition of amounts in the deferral accounts. However, the IRP Framework notes that 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.

- **IRP Working Group:** The OEB established an IRP Working Group led by OEB staff with 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. The initial priorities of the Working Group were identified as the consideration and implementation of IRP pilot projects, and enhancements or additional guidance in applying the DCF+ evaluation methodology. The IRP Working Group also files its own annual report, which includes any comments on Enbridge Gas's annual IRP report, including material concerns that remain unresolved, and also describes other activities undertaken by the Working Group.

## 5.2 Developments Since Release of IRP Framework

**Additional IRP guidance:**

Various OEB decisions have provided additional IRP-related guidance since the original IRP decision.

The decision on phase 1 of Enbridge Gas's rebasing application[38] made several IRP-related determinations including: providing Enbridge Gas with the ability to implement negotiated interruptible rates as part of an IRP Plan; incorporating an envelope for general IRP-related operations, maintenance, and administration costs into base rates; and making modifications to the IRP Costs deferral accounts.

Other OEB decisions have approved negotiated settlement conditions for new IRP-related requirements for Enbridge Gas that were not part of the original IRP Framework, as shown in Table 4.

[38] EB-2022-0200

**Table 4. New IRP Requirements for Enbridge Gas Resulting from Settlement Agreements**

| Requirement | Proceeding |
|---|---|
| Develop an approach to a system pruning pilot in consultation with the IRP Working Group by the end of Q2 of 2025 and begin implementation on one or two pilots by the end of Q1 of 2026. OEB approval is not required if the combined costs of these pilots are $5 million or less and the pilot(s) are supported by the IRP Working Group. | EB-2024-0111 |
| File a report on the status of Enbridge Gas's responses to previous IRP directions. | EB-2024-0111 |
| Propose an IRP incentive mechanism in its next IRP Plan application to the OEB. If there is no IRP Plan application within the next year, then Enbridge Gas will file a standalone application or request to the OEB for approval of an IRP incentive mechanism within that same timeframe. | EB-2024-0111 |
| Include in any future IRP Deferral Account clearance requests, details on the outcomes and ratepayer benefits related to each category of costs proposed to be cleared. This will include metrics on the percent of AMP projects that have been screened for IRP, the percentage of projects that have passed the screen that have been assessed, and the average length of time for Enbridge Gas to screen and assess projects. | EB-2024-0125 |

The IRP Framework is applicable to Enbridge Gas only. However, the OEB's Natural Gas Facilities Handbook (issued in 2022) references IRP and requires all rate-regulated natural gas distributors to provide evidence as to how IRP Alternatives have been considered as an alternative at the preliminary stage of project development in any pipeline Leave to Construct applications.

**IRP Working Group:**

The IRP Working Group has been meeting since early 2022. As required by the original IRP Framework, the Working Group's annual reports have been filed with the OEB, along with Enbridge Gas's IRP annual reports, in the Enbridge Gas Deferral and Variance Account clearance proceeding. Comments from some members have often been critical of aspects of Enbridge Gas's implementation of IRP. Materials related to the IRP Working Group can be found on the OEB's Engage With Us website.

The IRP Working Group has provided input to Enbridge Gas on many aspects of IRP implementation (e.g., the program design and evaluation strategy of both the Southern Lake Huron and system pruning pilots, the DCF+ test, the IRP Assessment Process, etc.).

## 5.3 Analysis and Proposals

### 5.3.1 Form and Applicability of an Updated IRP Framework

OEB staff proposes that an update to the IRP Framework is desirable, both to reflect developments since 2021 and to incorporate any further changes arising from this consultation that the OEB determines to be appropriate.

A high-level question is whether the current form of the IRP Framework (i.e., part of a Decision and Order applicable only to Enbridge Gas) should continue.

Some other approaches used by the OEB are shown in Table 5.

**Table 5. Other OEB Models for Regulatory Guidance That Could Inform an Updated IRP Framework**

| OEB Guidance | Key Procedural Differences from IRP Framework |
|---|---|
| Non-Wires Solutions Guidelines | • OEB policy document applicable to all rate-regulated electricity distributors.<br>• Higher-level than IRP Framework (exception: detailed Benefit-Cost Analysis guidance). |
| Demand-Side Management (DSM) Plan and Framework | • Policy framework and a DSM Plan compatible with the Framework are reviewed and updated in the same (adjudicative) proceeding[39].<br>• DSM Plan covers a specific time period; DSM Framework does not have a sunset date. |
| Framework for Distributor Gas Supply Plans | • OEB policy document applicable to all rate-regulated natural gas distributors.<br>• Distributors must submit a comprehensive gas supply plan (compatible with Framework) for detailed review every five years.<br>• Annual gas supply plan update filed with stakeholder review process, including OEB staff report (not adjudicated). |

[39] The most recent approved DSM Framework was established in an adjudicative proceeding for Enbridge Gas (EB-2021-0002). The previous DSM Framework was applicable to all rate-regulated natural gas distributors and established through a policy consultation (EB-2014-0134).

A closely related question is whether the updated IRP Framework should be applicable to Enbridge Gas only, or to all rate-regulated natural gas distributors (i.e., inclusive of EPCOR Natural Gas Limited Partnership).[40]

Procedural options for developing an updated IRP Framework therefore could include:

- Enbridge Gas drafting and filing an updated IRP Framework for adjudicative review and approval (Enbridge-only adjudicative proceeding).
- OEB staff drafting and filing an updated IRP Framework for adjudicative review and approval (generic proceeding or Enbridge-only proceeding).
- The OEB drafting and issuing a non-adjudicated updated IRP Framework as a policy document (which may also be applicable to EPCOR).

Regardless of which procedural option is chosen, it is expected that the proposals in this Discussion Paper, as well as responding comments and proposals from stakeholders participating in this consultation, would inform the drafting of the updated IRP Framework and the OEB's ultimate determination.

OEB staff is not proposing a preferred procedural option to updating the IRP Framework at this time, but notes:

- An adjudicative approach (as opposed to policy guidelines) provides greater authority to set binding requirements (which can include time-bound requirements) on the regulated entity.

There is a large difference in the size (and number of potential projects suitable for consideration of IRP Alternatives) between the two rate-regulated natural gas distributors. In addition, Enbridge Gas has spent considerable time and effort implementing the expectations of the original IRP Framework, such that any updated IRP Framework could build on these efforts. An IRP Framework applicable to both natural gas distributors would likely need to be a higher level of detail than the current IRP Framework for Enbridge Gas.

[40] Throughout this discussion paper, the descriptions of OEB staff proposals for an updated IRP Framework refer to the expectations for Enbridge Gas (consistent with the existing IRP Framework). Should the OEB determine that an updated IRP Framework will apply to all rate-regulated distributors, the OEB staff proposals would generally also apply to all rate-regulated distributors.

### 5.3.2 Forward-Looking IRP Implementation Plan

OEB staff notes that, despite the existence of the IRP Working Group, significant time has been spent examining IRP issues in various regulatory proceedings (Table 6). This has sometimes included examination of general methodological issues around IRP, such as approaches to assessing IRP technical potential and economic evaluation of IRP Alternatives.

**Table 6. Adjudicative Proceedings With IRP Aspects**

| Application Type | IRP Aspects |
|---|---|
| Cost of Service | IRP in context of AMP and rate base additions; general IRP operations, maintenance, and administration costs, use of interruptible rates |
| Leave to Construct | IRP as alternatives to proposed pipeline projects requiring Leave to Construct |
| IRP Plan (including IRP Pilots) | Need for, and cost consequences of, IRP Plans (including pilots) |
| Annual Deferral and Variance Account Clearance | Filing of IRP annual reports (informational) and clearance of IRP Costs deferral accounts |
| ICM | Updated AMP/AMP addendum, including status of consideration of IRP Alternatives |

Another challenge with the oversight approach in the current IRP Framework is that the regulatory proceeding in which the annual report is filed was not intended to provide an opportunity for adjudicative review of IRP implementation, or to consider the evolution of IRP policy. There is also no mechanism for the OEB to immediately assess and address concerns on IRP implementation raised by the IRP Working Group.

To address these challenges, OEB staff proposes that, whichever procedural option for updating the IRP Framework is selected, Enbridge Gas should be required to file a forward-looking IRP Implementation Plan compatible with the updated IRP Framework, to be reviewed through adjudication. A potential benefit of this proposal is that it may be more efficient and lead to more consistent outcomes for IRP-related issues to be considered in a dedicated regulatory proceeding outside of project-specific applications.

OEB staff proposes the following approach under an updated IRP Framework[41], which draws on aspects of several of the OEB procedural models described in Table 5:

- Once the IRP Framework is updated, Enbridge Gas would be required to develop and file a forward-looking IRP Implementation Plan for approval, to be adjudicated, covering a defined period, potentially three years. This would serve as a compendium of Enbridge Gas's current IRP practices,[42] outline actions and priorities for the next three years and would be supported by an up-to-date AMP.
- Key supporting IRP policy/guidance documents that Enbridge Gas has developed to implement the IRP Framework would be considered (explicitly or implicitly) in the approval request. OEB staff expects that these supporting policies would likely include:
    - The enhanced DCF+ test.
    - IRP Assessment Screening and Evaluation Guidelines.
    - Enbridge Gas's approach to valuing stranded asset risk in the context of IRP assessment.
    - Enbridge Gas's approach to quantifying the technical potential of IRP Alternatives, including demand-side alternatives and peak demand reductions from contract customers.
    - Enbridge Gas's approach to quantifying the offsetting amounts in the IRP Costs deferral account balances to reflect avoided capital cost impacts related to facilities projects that are delayed, avoided or downsized by IRP.[43]
    - Enbridge Gas's proposed Shareholder Incentive Mechanism for IRP Plans (if not processed by the OEB through a separate application).

[41] This proposal was informed by discussion with the IRP Working Group (meetings #54 and 55) and follow-up comments provided by Working Group members, but does not adopt all suggestions by members. For example, some Working Group members were in favour of the entire Utility System Plan or AMP (not just IRP aspects) requiring explicit review and approval from the OEB. The OEB's practice has been to consider Utility System Plans and AMPs for electricity or natural gas distributors in the context of capital funding requests, particularly in cost-of-service applications, but not to formally approve these plans. A related suggestion was that each year's AMP update or IRP Implementation Plan update should require OEB approval (albeit at a lower level of regulatory scrutiny than the initial review of the plan).

[42] See the NPA Implementation Plans of National Grid and Consolidated Edison in New York State for examples.

[43] EB-2022-0200, Settlement Agreement, Exhibit O1, Tab 1, Schedule 1, p.54.

OEB staff recognizes that some of these policies are still evolving and under discussion with the IRP Working Group. However, the current versions of the first four of these policies are being used today and therefore have consequences for Enbridge Gas's implementation of IRP, including impacting determinations as to whether IRP Alternatives are selected to address system needs, as discussed in section 3.2. Adjudicative review would build on prior changes to these policies and procedures made by Enbridge Gas in response to input from the IRP Working Group. OEB staff believes that this would produce regulatory efficiencies for Enbridge Gas in other proceedings, for example by avoiding the need to litigate policies/guidance or their application within Leave to Construct proceedings.

OEB staff also believes that Enbridge Gas should be provided some flexibility in how it frames its IRP Implementation Plan approval request regarding supporting IRP policies and guidance documents, although the enhanced DCF+ test and Shareholder Incentive Mechanism, at a minimum, should require explicit approval. OEB staff notes that for mature policies and guidance documents, the OEB may take ownership, with examples including the Technical Resource Manual used in the natural gas DSM Framework to standardize savings assumptions for energy efficiency measures and the Benefit-Cost Analysis cost effectiveness test for non-wires solutions. However, given that IRP is still rapidly evolving, it may make sense for some IRP policies and guidance documents to remain under Enbridge Gas's ownership and open to further change (after the approval of the IRP Implementation Plan). This is similar to the approach taken for Enbridge Gas's DSM activities, where relevant supporting policies and guidance documents can be considered by the OEB as part of its determination in the adjudicated DSM Plan proceedings.

- The IRP Implementation Plan could also make requests related to cost recovery (e.g., rate riders, and/or ability to record certain costs in IRP deferral accounts) associated with activities in the IRP Implementation Plan (e.g., IRP Plans to address specific system needs, pilot projects, or other innovation-related proposals). It is not expected that Enbridge Gas would be able to forecast with certainty all system needs over the 3-year term that would be met with IRP Plans, a concern noted by IRP Working Group members. For this reason, Enbridge Gas would still have an option of bringing forward separate IRP Plans addressing specific system needs at a later date.

- The draft IRP Implementation Plan would first be reviewed by the IRP Working Group. Enbridge Gas would document its consideration of Working Group comments in its final filed Implementation Plan.

- In each year, Enbridge Gas would still file an IRP annual report (which could note modifications to its implementation plan) to support clearance of its IRP Costs deferral accounts, consistent with current practice. The OEB's review would be limited to findings on disposition of amounts in the deferral accounts, unless Enbridge Gas was requesting any new approvals related to changes to its IRP Implementation Plan.

OEB staff recommends that the first IRP Implementation Plan be a stand-alone application. In the future, one option would be to encompass the requirement for an IRP Implementation Plan within Enbridge Gas's rebasing application. This has the advantage that IRP implementation can be considered along with Enbridge Gas's planned capital spending (which is supported by Enbridge Gas's AMP). However, IRP Working Group members raised a concern that the rebasing proceeding already needs to deal with many issues, and that IRP issues could be overshadowed if considered in the same proceeding.

If the OEB Staff proposal for an adjudicated IRP Implementation Plan is adopted, the updated IRP Framework could be drafted at a relatively high level of detail to avoid being overly prescriptive and inflexible. This may mean that there would be less need to update the IRP Framework in future, although this is difficult to predict with certainty. If the updated IRP Framework is also applied to EPCOR, OEB staff would recommend that the requirement for an IRP Implementation Plan (if adopted) not take effect for EPCOR until a later date, following approval of Enbridge Gas's initial IRP Implementation Plan.

### 5.3.3 Evolution of IRP Working Group

The IRP Working Group has provided useful advice that has helped Enbridge Gas refine and improve many aspects of IRP implementation. However, this has come at a significant cost and effort relative to results achieved. Further, the IRP Working Group has not been able to act as a substitute for formal regulatory review of IRP issues.

The IRP Working Group has been most efficient and effective when supported by a clear ask and time-bound deadline from an adjudicative proceeding (e.g., development of the approach to the system pruning pilot) and has found it challenging to reach consensus (particularly between non-utility and Enbridge Gas members) on IRP issues with policy implications.

OEB staff sees value in a continuing role for the IRP Working Group as a consultative body, but not as a substitute for regulatory approval of substantive IRP-related policies or proposals. If the OEB staff proposal for an adjudicated IRP Implementation Plan is adopted, OEB staff proposes that the IRP Working Group review and provide substantive input on a draft of the IRP Implementation Plan prior to adjudication.

Enbridge Gas would document its consideration of the IRP Working Group's comments in its final filed IRP Implementation Plan. In addition, the IRP Working Group would review and comment on a draft of the Enbridge Gas's annual IRP report (including its updates to the IRP Implementation Plan). OEB staff proposes that these be the IRP Working Group's only ongoing responsibilities explicitly defined in the IRP Framework. However, additional expectations for the IRP Working Group could also be established through adjudication in IRP-related proceedings (for example, further input into design and implementation of any innovation-related proposals that the OEB approves through its decision on Enbridge Gas's IRP Implementation Plan, as discussed in chapter 6).

## 5.4 Discussion Questions

2. Which of the procedural options, if any, for updating the IRP Framework do you prefer, and why?
3. Should any updated IRP Framework be specific to Enbridge Gas, or applicable to all rate-regulated gas distributors?
4. Does the level of detail in the current IRP Framework strike an appropriate balance between:
   (a) defining the OEB's expectations and providing regulatory certainty on IRP
   (b) Allowing for flexibility and evolution in Enbridge's approach to IRP implementation?
    a. Would more or less detail be preferable in an updated IRP Framework?
5. Do you support the OEB staff proposal for an IRP Implementation Plan? What modifications, if any, to this proposal, and to the annual reporting approach, would you suggest?
    a. How frequently should an IRP Implementation Plan be developed and reviewed? Should the IRP Implementation Plan be reviewed as part of, or separately from, Enbridge Gas's rebasing application?
6. How do you see the role of the IRP Working Group evolving under an updated IRP Framework? Do you agree with OEB staff's proposed approach? Why or why not?

# 6. FRAMEWORK REVIEW TOPIC 2: INNOVATION

*"The OEB's expectations and approach to oversight of innovation-related IRP Proposals"*

## 6.1 Requirements in IRP Framework

The current IRP Framework does not refer explicitly to innovation, but to IRP pilots. The July 2021 Decision and Order directed Enbridge Gas to bring forward two IRP pilots by the end of 2022. The OEB indicated that 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 does not provide specific guidance as to areas of focus for the pilots, indicating that the nature of the pilots should be responsive to the opportunities that arise. The IRP Framework also identified the consideration and implementation of IRP pilot projects as a key activity for the IRP Working Group.

The IRP Framework required the pilots to be filed with the OEB for approval. The IRP Framework does not describe a distinct process for reviewing, adjudicating, or approving IRP pilots, but indicates that the IRP pilot applications should generally provide the information and follow the approach used for (non-pilot) IRP Plans that would be developed to address a defined system need.

## 6.2 Developments Since Release of IRP Framework

Enbridge Gas has made progress on IRP pilot implementation, but not at the pace expected by the original Decision. After assessment of pilot opportunities against system needs in Enbridge Gas's AMP and consultation with the IRP Working Group, Enbridge Gas did not file its IRP Pilot Project application (EB-2022-0335) until July 2023. Enbridge Gas generally followed the IRP Plan informational requirements for its IRP Pilot Project application, although certain aspects did not apply due to the pilot nature of the project.

The delay in IRP pilot implementation is partly due to a prolonged and disrupted process involved in preparing, reviewing, updating and adjudicating the IRP Pilot Project application. Enbridge Gas initially proposed two IRP pilots as part of this application but withdrew one pilot (in the Parry Sound area) due to changes to its demand forecast that removed the need for this project.

Additionally, the proceeding was placed in abeyance from November 2023 until August 2024, further extending the timeline. A decision on the IRP Pilot Project application, covering the remaining pilot (Southern Lake Huron), was issued by the OEB on March 27, 2025. The OEB initiated a review of certain elements of the decision.[44]

The primary objectives of the Southern Lake Huron pilot are to develop an understanding of how demand-side IRP Alternatives, including ETEE and demand response, impact peak hour flow/demand and to develop an understanding of how to design, deploy, and evaluate ETEE and residential demand response programs.

Enbridge Gas is proceeding with most aspects of the Southern Lake Huron pilot as approved by the OEB, except for the direction to redirect funds for advanced gas technologies to electrification IRP Alternatives, which is expressly at issue in the OEB's review motion. Enbridge Gas will not be including advanced gas technologies in the Southern Lake Huron pilot until further direction is provided.

Another aspect of the IRP Pilot Project decision required Enbridge Gas to analyze additional IRP pilot opportunities that it identified with the IRP Working Group, and report back as part of its 2025 IRP annual report (expected to be filed in June 2026). The decision encouraged Enbridge Gas to submit an application to the OEB should it identify a promising pilot before this time. Enbridge Gas has requested that the OEB stay this portion of the IRP Pilot Project decision until the guidance from the IRP Framework review is received.

Separate from the IRP Pilot Project proceeding, in November 2024, the OEB issued a decision approving a partial settlement proposal with respect to Phase 2 of Enbridge Gas's rebasing application (EB-2024-0111). The Phase 2 decision established a new process to develop, review and implement an additional IRP-related system pruning (proactive decommissioning of a portion of the natural gas system that is no longer required to serve the needs of energy users) pilot, requiring Enbridge Gas to work with the IRP Working Group to identify one or two system pruning pilots to be implemented by 2026.[45] Under the settlement proposal, advance OEB approval is not required if the combined costs of the pilot project(s) are $5 million or less and the project(s) are supported by the IRP Working Group.[46] The decision also allows for a new IRP System Pruning Deferral Account with a $5 million cap for tracking and recovering incremental

[44] Notice of Review on the OEB's Own Motion, EB-2025-0124, March 27, 2025

[45] Decision on Settlement Proposal and Interim Rate Order, Phase 2, Enbridge Rebasing (EB-2024-0111), November 29, 2024, p.7.

[46] Decision on Settlement Proposal and Interim Rate Order, Phase 2, Enbridge Rebasing (EB-2024-0111), p.7-8.

pilot project costs.[47] Enbridge Gas subsequently developed an approach to the system pruning pilot in consultation with the IRP Working Group, and filed its approach with the OEB in July 2025.[48]

## 6.3 Analysis and Proposals

### 6.3.1 Enabling and Defining Innovation-related IRP Proposals

OEB staff supports providing flexibility in the updated IRP Framework for Enbridge Gas to propose and seek cost recovery for innovation-related IRP proposals that would be incremental to activities addressed in approved base rates. More learnings are needed to better understand the potential of IRP and the role it can play over the longer term in addressing Enbridge Gas's system needs. In considering the oversight of innovation-related IRP proposals, OEB staff proposes innovation be considered in a broad sense, similar to the guidance provided for electricity distribution activities[49]:

> "Innovation has broad meaning: It can relate to the use of new technology, or new ways in which to use existing technologies. It could also include innovative business practices, including relationships with others to enhance services to customers and share costs."

For the purposes of the updated IRP Framework, OEB staff proposes to define innovation-related IRP proposals as **discrete initiatives aimed at testing the appropriateness of new technologies, approaches or practices to advance or improve the understanding of how IRP can address the system needs of Enbridge Gas's regulated operations and implement the alternative (or combination of alternatives) that is in the best interest of Enbridge Gas and its customers.**

---

[47] Decision on Settlement Proposal and Interim Rate Order, Phase 2, Enbridge Rebasing (EB-2024-0111), p.8.

[48] Enbridge Gas 2024 IRP Annual Report, Appendix G

[49] Filing Requirements for Electricity Distributors, Ch. 2, p.13

This definition aligns with the definition of IRP in the existing IRP Framework and generally aligns with the stated goals of the IRP pilots as set out in the 2021 Decision and Order, in which pilots were expected to:

- Support understanding and evaluation of how IRP can be implemented to avoid, delay or reduce facility projects.[50]
- Reduce the risk of inadequate consideration of alternatives and promote more prudent and effective integrated resource system planning.[51]

Innovation-related IRP proposals would be distinguished from IRP Plans in the updated IRP Framework. While IRP Plans require Enbridge Gas to demonstrate that an IRP Alternative (or combination of Alternatives) is the preferred option to address an identified system need (including considerations of technical viability and cost-effectiveness), **innovation-related IRP proposals are primarily intended to support learning and inform future IRP implementation**. As such, it is likely not appropriate to assess innovation-related IRP proposals using the same criteria as IRP Plans.

### 6.3.2 Oversight of Innovation-related IRP Proposals

Given that innovation-related IRP proposals are primarily intended to support learning and future IRP implementation, OEB staff propose that they should be assessed through a process distinct from that used for IRP Plans designed to meet identified near-term system needs. OEB staff considered four mechanisms by which to oversee innovation-related proposals (and their associated costs), summarized in Table 7 below. In the first three options, it is assumed that recovery of the costs of innovation-related proposals may occur through the IRP deferral accounts, but would be subject only to general prudence considerations, given the upfront approval provided.

[50] 2021 Decision and Order, p. 9

[51] 2021 Decision and Order, p. 61

### Table 7. Potential Mechanisms for Oversight of Innovation-related IRP Proposals

| Oversight Mechanism | Description |
|---|---|
| 1) Advance project-specific approval by OEB | Follows the current process outlined in the 2021 IRP Framework (innovation-related proposals are treated as variants of full IRP Plans). |
| 2) Advance review and endorsement by the IRP Working Group with pre-determined criteria | Based on the approach used in the Enbridge Gas Phase 2 Rebasing decision on system pruning pilots, proposals could be approved if they meet pre-set criteria (e.g., combined project costs of $5 million or less) and receive endorsement from the IRP Working Group. |
| 3) Advance approval by the OEB of an IRP Implementation Plan | Innovation-related IRP proposals, including potential benefits and estimated costs, are included in a three-year IRP Implementation Plan, and are subsequently eligible to be recorded in the IRP Costs deferral accounts. |
| 4) No advance review and approval | Definition of IRP Costs deferral accounts is expanded such that recovery of incremental IRP-related costs for innovation proposals are automatically eligible to be recorded in the IRP Costs deferral accounts (recovery subject to prudence review). |

The **first option** reflects the current process, where IRP pilots or innovative proposals are treated as variants of IRP Plans, and subject to upfront project-specific adjudicative review. This approach enables broader stakeholder input and OEB review through an adjudicated proceeding. However, as evidenced by the lengthy process leading to the IRP Pilot Project decision (considering both pre-adjudicative and adjudicative aspects), the adjudicative process may hinder the approval and testing of emerging solutions. Time-sensitive proposals may face delays due to the extensive resources needed for application preparation, adjudication, and deliberation.

The **second option** offers a potentially more streamlined process, relying on endorsement from the IRP Working Group. Under this approach, innovative proposals would undergo review from the Working Group without the formal process and potentially longer timelines associated with adjudicated proceedings. This could accelerate the deployment of new solutions and reduce administrative burden. This approach has worked well with the system pruning pilot proposal to date, given that Enbridge Gas was able to develop an approach to this pilot in consultation with the

Working Group under an accelerated timeline.[52] However, Working Group members noted that this approach limits participation from other stakeholders, which may affect transparency and broader buy-in. It is also unclear how issues of non-consensus would be resolved and whether the experience with the system pruning pilot will be replicable for other pilots. OEB staff notes that for the pilot proposal that eventually led to the IRP Pilot Project application, the Working Group could not reach consensus on the issue of including advanced gas-fired technologies in that pilot. To be effective, this review option may also require consensus on project design or the establishment of a formal governance protocol (e.g., majority consent or predefined decision rules).

The **third option** involves the advance approval of a multi-year IRP Implementation Plan (as discussed in chapter 5), including its innovation-related IRP proposals. **This option is currently preferred by OEB staff.** The IRP Implementation Plan could outline details of innovation-related IRP proposals that Enbridge Gas intends to pursue (potentially at a higher or more preliminary level of detail than would be expected in a stand-alone innovation proposal application), including any approvals requested related to cost consequences of these proposals. The forward-looking IRP Implementation Plan would be adjudicated, including opportunities for broad stakeholder input. An approved IRP Implementation Plan would then allow Enbridge Gas to refine and implement initiatives more nimbly, while prudence reviews of subsequent spending recorded in the IRP Costs deferral accounts would continue to provide for OEB oversight.

As noted in chapter 5, the OEB's adjudicative determination on the IRP Implementation Plan could also potentially establish requirements for the Working Group to provide further review of design and implementation of approved innovation-related proposals in the IRP Implementation Plan, should the OEB panel reviewing this application believe these conditions to be necessary. OEB staff believes that to preserve flexibility, it is likely preferable to leave this as an open-ended option that an OEB panel could choose to utilize, rather than enshrining such expectations in the IRP Framework itself.

The **fourth option** considered would make use of, and potentially modify the definitions of, the two existing IRP Costs deferral accounts for incremental IRP-related operating and capital costs not included in base rates and would not require advance review and approval for innovation-related IRP proposals.

The IRP Costs deferral accounts currently enable Enbridge Gas to record and subsequently seek disposition of costs associated with approved IRP Plans, as well as incremental general IRP administrative costs (which are not tied to an approved IRP

[52] The Working Group did not formally approve the proposal but supports proceeding with it as a reasonable initial approach, subject to ongoing review and further input as the pilot is implemented and lessons are learned. EB-2025-0064, Exhibit I.1.13-ED-4, Attachment 1, Page 110 of 321

Plan). As part of updating the IRP Framework, the definition of the IRP Costs deferral accounts could be extended to include costs associated with innovation-related IRP proposals (potentially with a defined cost threshold).

This option provides the greatest degree of flexibility to Enbridge Gas to quickly implement innovation-related proposals, with oversight limited to the after the fact prudence review when it seeks disposition of the IRP Costs deferral accounts. However, from Enbridge Gas's perspective, without advance endorsement by the OEB and/or the IRP Working Group, there may be a greater risk of the OEB determining that the project was not prudent and disallowing costs at the time Enbridge Gas seeks disposition.

### 6.3.3 Assessing Innovation-related IRP Proposals

Under the existing framework, no specific criteria exist for evaluating innovation-related proposals. The updated IRP Framework could establish clear, fit-for-purpose criteria for evaluating innovation-related proposals. Drawing from the OEB's approach with electricity distributors,[53] these proposals could be assessed against defined considerations that balance flexibility and accountability. This would provide greater clarity for Enbridge Gas and stakeholders while maintaining regulatory oversight.

When developing or seeking approval for an innovation-related IRP proposal, OEB staff proposes that Enbridge Gas should be required to address five considerations like those identified in the OEB's guidance to electricity distributors on innovation-related proposals. These considerations may be applied proportionally to the size and forecast cost of the innovation proposals, with an expectation of increased detail and scrutiny for larger-scale initiatives.

1. **Potential to Address System Needs**: Identify the rationale for the proposal and its novel features, including an assessment of whether and how the proposed solution, if successful, could contribute to meeting future system needs. The rationale could include a description of potential costs and benefits of the proposal. The submitted rationale could also include a comparison of the technical and economic viability of the proposed innovation versus traditional solutions (or other categories of IRP Alternatives), even if this comparison is less detailed or more uncertain than what would be provided for an IRP Plan.
2. **Risk and Oversight**: Describe potential risks and uncertainties, including those that may affect customers, and mitigation strategies including governance and oversight structures.

[53] Innovation-related Proposals in Rate Applications, OEB letter, March 20, 2025

3. **Evaluation and Scalability**: Identify how the outcomes of the proposed solution would be evaluated and assessed and outline a transition plan for broader deployment if the proposal proves successful, including key milestones and decision points.
4. **Alternative Funding**: Explore opportunities for alternative funding sources to reduce reliance on ratepayers (e.g., government programs, contributions from private sector technology partners).
5. **Knowledge Sharing**: Include a mechanism for sharing lessons learned to support sector-wide learning and inform future proposals.

OEB staff does not propose that any specific innovation-related proposal should be mandated under the updated IRP Framework, and believe this is likely better left for Enbridge Gas's consideration through the IRP Implementation Plan.

As noted in chapter 7, there may be value in a pilot that looks at electrification as an alternative to new customer gas connections. The OEB has provided some additional suggestions for potential pilots in the IRP Pilot Project decision.[54]

One other option which OEB staff believes is worth further exploration is the potential use of competitive solicitation to deliver demand reductions from third parties, as opposed to utility-run programs. Utilities in New York and Rhode Island, for example, have made use of the solicitation of NPAs through requests for proposals as a market-based approach to identify and deploy cost effective solutions.[55] For instance, in June 2021, the New York State Public Service Commission authorized New York State Electric and Gas to proceed with procuring a portfolio of seven NPA projects for a total cost of US$9.7 million to provide a total hourly natural gas peak demand reduction of up to 56 million cubic feet per hour in order to improve the low-pressure situation in the Lansing area and displace the need for additional gas infrastructure in the future.[56]

---

[54] pp. 11-12 of the Decision and Order.

[55] Non-Pipeline Alternatives to Natural Gas Utility Infrastructure: An Examination of Existing Regulatory Approaches, Strategen for Lawrence Berkeley National Laboratory, November 2023.

[56] NYSEG Lansing Non-Pipes Alternatives Implementation Plan: New York Non-Pipes Alternatives, January 29, 2025, pp. 8-9. Two developers subsequently withdrew their proposals resulting in a portfolio of five NPA projects for a total cost of US$8.8 million to provide a total demand reduction of 49.2 million cubic feet per hour.

## 6.4 Discussion Questions

7. Do you support the definition of “innovation-related IRP proposals” as proposed by OEB staff? Why or why not?
    a. Are there additional elements or considerations you believe should be emphasized or included to better define the scope of innovation-related IRP proposals?
8. Which, if any, of the four proposed oversight mechanisms for innovation-related proposals do you support and why?
    a. What modifications to the proposed oversight mechanisms, if any, would you suggest?
9. What assessment criteria would best support value-driven innovation? Do you agree with the five considerations proposed by OEB staff? If not, what changes would you propose?

# 7. FRAMEWORK REVIEW TOPIC 3: ELECTRIFICATION AS AN IRP ALTERNATIVE

*"Expectations for natural gas distributors regarding electrification as an IRP Alternative, including how electricity availability issues should be considered if electrification is being proposed as an IRP Alternative"*

## 7.1 Requirements in IRP Framework

Enbridge Gas sought approval to use non-gas alternatives, including electricity-based solutions, as IRP Alternatives. The OEB concluded that as part of the first-generation IRP Framework, it was not appropriate to provide funding to Enbridge Gas for electricity IRP Alternatives, but that this may change as energy planning evolves, and as experience is gained with the IRP Framework. The IRP Framework notes that Enbridge Gas can 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 IRP Alternatives or facility projects undertaken by Enbridge Gas, but this is not a requirement.

The IRP Decision and Order also noted that in the longer term, there may be an opportunity to conduct integrated energy resource planning with consideration given to the optimal fuel choice between all energy sources, but this would be an excessively challenging requirement during the first-generation IRP Framework.

In the original IRP Framework proceeding, some parties expressing concerns around electrification IRP Alternatives 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*, particularly if they involved avoiding the connection of new natural gas customers. The OEB did not directly address this issue in its decision.

## 7.2 Developments Since Release of IRP Framework

The energy planning landscape has evolved since the IRP Decision and Order.

**DSM Incentives for Electrification:**

In 2022, the OEB granted Enbridge Gas approval to use ratepayer funds for electrification measures (heat pumps) as part of its DSM programs.[57] This funding was originally approved in the context of providing complementary funding for measures eligible for incentives through the Government of Canada's Greener Homes Grant program, but was subsequently continued after the Greener Homes Grant program was closed.

**Electrification in IRP Pilots:**

Enbridge Gas subsequently proposed including electrification measures (incentives for cold climate air source heat pumps and ground source heat pumps) as part of its IRP Pilot Project application for a limited number of pilot participants. This would build on the electrification incentives offered through its DSM programs. Enbridge Gas indicated that the IRP Pilot Project offered an opportunity to evaluate the potential applicability and feasibility of electrification measures in an isolated environment, but commented that broader implementation of electrification measures in the future would require integrated energy planning across energy sources, including discussion and engagement between Enbridge Gas and the electric sector, to ensure a holistic assessment of the impact of these types of measures on the respective grid and system. For the IRP Pilot Project, Enbridge Gas met with the local electricity distributor in the pilot area to confirm that the additional electrical load demand from the limited number of measures would not have a material impact to the local electricity grid.

The OEB's decision on the IRP Pilot Project approved the funding for electrification measures, but also directed Enbridge Gas to reallocate the proposed budget for advanced gas-fired technologies to electrification measures to increase the number of participants and to potentially expand the types of electrification measures (e.g., combination water heating/space heating) offered.

The OEB initiated a review of certain elements of this decision. Enbridge Gas is proceeding with the limited electrification proposed in its application, but is not currently implementing the direction to redirect funds for advanced gas technologies to

[57] EB-2021-0002 Decision and Order, November 15, 2022

electrification IRP Alternatives, which is at issue in the OEB's notice to review the Decision.

Electrification will play a larger role in Enbridge Gas's system pruning pilot, which involves converting willing customers served by a portion of the natural gas system off of natural gas, and providing incentives for these customers to replace their natural gas equipment with (predominantly) electric equipment.[58]

If this approach shows promise, it may lead to IRP projects targeting proactive decommissioning of a portion of the natural gas system requiring repair or replacement, if doing so is more cost-effective than replacing gas infrastructure. This would only be done if all customers served by that portion of the pipeline system were willing to disconnect.

Some objectives of the system pruning pilot include better understanding the economics of conversion relative to replacing mains and services from both the utility and customer perspective, and understanding what data or other information is relevant to collect for the IESO and the local distribution company in the pilot area.

**New expectations for integrated energy planning**:

The IEP indicates that developing a single, integrated plan for all energy needs is a priority, and notes that, if done right, integrated planning will deliver a range of system-wide benefits, including avoiding risks of higher costs due to overbuilding or underbuilding of energy infrastructure, enabling fuel switching when it is cost-effective, and focusing on customers' total energy bills, instead of electricity and other fuel bills separately.[59]

The associated IEP Implementation Directive to the OEB[60] set new expectations for the OEB in regards to integration of natural gas and electricity planning, including directing the OEB to:

- Establish an ongoing gas-electric coordination information sharing forum in support of integrated energy planning, supporting information sharing in the short-term and establishing the use of consistent assumptions and scenarios in the medium-term, and requiring participation of key energy planners (including the IESO, electricity and gas utilities, and others).

[58] Enbridge Gas 2024 IRP Annual Report, Appendix G

[59] Ontario's Integrated Energy Plan, chapter 7, pp. 119-120

[60] Order-in-Council 802-2025, June 12, 2025

- Set the expectation for natural gas and electricity distributors to incorporate multiple demand scenarios for their planning frameworks and processes, including a reference case reflecting current trends and policies and high and low demand scenarios, and risk/uncertainty assessments.
- Encourage or require natural gas and electricity distributors to include certain information in their planning frameworks and processes, including, where pertinent and practical, if a system investment, policy, or program is intended to facilitate fuel switching, consider costs and benefits across impacted energy systems.

## 7.3 Analysis and Proposals

**Eligibility of electrification IRP Alternatives:**

OEB staff supports making electrification an eligible IRP Alternative in the updated IRP Framework. OEB staff expects that this will provide more opportunities to enable fuel switching across energy sources when it is cost-effective, consistent with the intent of the IEP.

Electrification can eliminate a customer's natural gas demand, so it can potentially deliver larger natural gas peak demand reductions than could be achieved by IRP Alternatives such as energy efficiency and demand response alone. The OEB's 2024 Achievable Potential study found that the technical potential for natural gas savings (not natural gas peak demand reduction, which was not explicitly assessed) more than doubled when fuel switching was in scope, compared with energy efficiency measures alone.

Including electrification as an eligible IRP Alternative is therefore likely to increase the number of system needs for which an IRP Alternative is determined to be a technically feasible alternative. As discussed in section 3.2.2, to date, IRP Alternatives based on energy efficiency have failed at the technical evaluation stage in several Leave to Construct proceedings based on insufficient peak demand reduction potential. However, to be selected as a preferred option to address a system need, IRP Alternatives that include electrification would also need to be economically feasible, which would be determined through the cost-effectiveness testing (DCF+). It is worth noting that the removal of the Federal Carbon Charge reduces the cost-effectiveness of electrification solutions.

OEB staff proposes that electrification be added as an eligible IRP Alternative for Enbridge Gas, primarily in the context of being one of the measures that could be used in an IRP Plan to avoid or defer an identified upstream system reinforcement project. In such cases, electrification measures could be offered to both existing customers and potential new customers, avoiding the customer connections costs for these new customers (in addition to the upstream system reinforcement cost). In areas where no upstream system constraint exists, Enbridge Gas would not be required to consider electrification alternatives to new customer connections. Additional details on the potential applicability of electrification as an IRP Alternative to system needs are shown in Table 8.

**Table 8. Potential Applicability of Electrification IRP Alternatives to Categories of Natural Gas System Needs**

| Category of System Need | Proposed Updated Approach to Electrification as an IRP Alternative |
|---|---|
| Customer connections | • In scope for IRP assessment only if connections are associated with identified upstream reinforcement project. |
| Community expansion | • Out of scope – projects selected for funding by government through Natural Gas Expansion Program would not require consideration of IRP Alternatives (including electrification). |
| System reinforcement (growth) | • In scope – Enbridge Gas could consider electrification measures for existing customers and potential new customers as part of an IRP Alternative to the planned reinforcement. |
| System renewal | • In scope – but potentially limited applicability. Consideration of IRP Alternatives for pipeline repair/replacement projects is only mandatory for projects over $2 million, and electrification is unlikely to be a viable IRP Alternative for major renewal projects, given the need for 100% disconnection of impacted customers for pipeline avoidance, and limited cost savings in most cases for pipeline downsizing. System pruning pilot will provide learnings as to whether electrification is a viable alternative for smaller main replacements. |

OEB staff's proposal is that any consideration of electrification as an IRP Alternative to connecting new customers would be limited to voluntary measures, such as incentives to developers (rather than connection bans) to preserve customer choice.

OEB staff also notes that there may be value in testing the approach of electrification IRP Alternatives as an alternative to new customer connections on a pilot basis first, to gain a better understanding of how this could work in practice (e.g., the willingness and required level of incentives to builders/developers to consider electrification, timing issues as to when new developments make a determination on their choice of energy sources, etc.). It is possible that other parties might also see value in contributing funding or partnering on such a pilot.

**Electricity availability issues:**

As noted in appendix B, the scale of electrification in other jurisdictions related to gas NPAs/system pruning has generally not been large enough to date to require co-ordination with electric utilities to assess impacts on electricity load, but building co-ordination procedures with electric utilities is recommended as a best practice, to enable gas and electric utilities to be prepared should larger electrification opportunities become available.

OEB staff proposes a relatively straight-forward approach to considering electricity availability issues that builds on the approach used in the IRP Pilot Project:

- For IRP Plans that include electrification measures, Enbridge Gas would be required to consult with the impacted upstream providers including distributor(s)[61] and the IESO as to whether electricity system upgrades would be required to accommodate the load, based on the expected electrical peak demand impact and location of the electrification IRP Alternative.
- If a potential electricity system upgrade was identified, the distributor(s) and/or IESO (as appropriate, depending on the nature of the identified upgrade), would be asked to provide approximate estimates of the cost and timing of the upgrade (including the base case as to whether and when an upgrade would be needed in the absence of the electrification IRP Alternative).
- Enbridge Gas could then use this information in further cost-effectiveness testing of the electric IRP Alternative or determine that it does not make sense to pursue the IRP Alternative in this area given the identified constraints.

OEB staff does not expect this requirement to impose significant new workload on the IESO or electricity distributors, although this could change if it turns out that Enbridge Gas identifies many cost-effective electrification IRP Alternatives.

**Assessing cost-effectiveness of electrification:**

Under the current IRP DCF+ test, incremental costs associated with electrification are accounted for by including the change in the electricity bill for customers participating in the IRP Alternative as a phase 2 impact, along with any incremental off-bill customer costs for electrification measures that are paid for by the participating customer (e.g., equipment costs, panel upgrades). Costs paid for by Enbridge Gas are included as phase 1 impacts.

[61] Where relevant and required the electricity distributor should consult with their upstream provider.

This goes some way towards identifying the lowest-cost solution from the perspective of both energy systems, but has limitations. In particular, it is not an accurate valuation of incremental electricity system costs when marginal system costs diverge greatly from rates, or when specific electricity infrastructure upgrades (not paid for by participating customers) are triggered by an electrification IRP Alternative.

OEB staff proposes that when a distributor or the IESO has identified a required electricity system upgrade, Enbridge Gas would also include the associated electricity system costs (incremental to phase 2) as a phase 3 impact, to be considered by Enbridge Gas and the OEB in determining whether the electrification IRP Alternative is the preferred option to address a system need.

At some point, it may be necessary to develop a common benefit-cost test used by both the gas and electricity sectors to consider the costs and benefits of fuel switching, but this is beyond the scope of the current IRP Framework review. A closely related issue is the question of cost allocation, and whether the electricity sector should pay for any of the costs of beneficial electrification associated with fuel switching from natural gas to electricity. OEB staff does not believe that these issues should prevent the OEB from allowing consideration of electrification IRP Alternatives in the updated IRP Framework, given that the scale of fuel switching associated with electrification IRP Alternatives is likely to be small, at least at first, and it is likely that learnings from including electrification in the IRP Framework may help inform future determinations on these larger policy questions.

**Other non-gas IRP Alternatives:**

Discussion of non-gas IRP Alternatives in the IRP Framework has been almost solely focused on electrification. However, thermal energy networks (district energy), which may have gas and/or non-gas energy supply sources, are another technology that has received attention as an IRP Alternative in other jurisdictions. Most notably, the New York Department of Public Service directed gas utilities to undertake thermal network pilot projects, with twelve pilots totaling $880 million in active development.[62] The IRP Pilot Project decision also refers to the possibility of a district energy pilot. As part of the IEP Implementation Directive, the OEB has also been directed to report on considerations around a potential mandate expansion to encompass district energy systems (along with other technologies).

Given these developments, OEB staff suggests that the updated IRP Framework should avoid an outright exclusion for other non-gas IRP Alternatives, to allow for the possibility

[62] New York Department of Public Service, “PSC Adopts Initial Utility Thermal Network Energy Rules”, 2024. PSC Adopts Initial Utility Thermal Energy Networks Rules | Department of Public Service

of Enbridge Gas bringing forward a proposal for OEB consideration if it identifies a promising IRP opportunity involving a non-gas IRP Alternative.

## 7.4 Discussion Questions

10. Are you in favour of expanding electrification as an eligible IRP Alternative beyond the current pilots? Why or why not?
11. Is there value in a pilot that includes electrification as an alternative to new customer connections (which is not part of the existing Southern Lake Huron pilot or the system pruning pilot)?
12. Are there any legal considerations or limitations relevant to the OEB's ability to approve funding for electrification or other non-gas IRP Alternatives under the *OEB Act* (natural gas rates)?
13. Do you have suggestions regarding the approach to identifying electricity system impacts triggered by an electrification IRP Alternative, or the approach to quantifying electricity system impacts in cost-effectiveness testing?

# 8. FRAMEWORK REVIEW TOPIC 4: OTHER OPPORTUNITIES TO IMPROVE THE EFFECTIVENESS AND EFFICIENCY OF IRP FRAMEWORK

This chapter describes three additional areas OEB staff has identified where there may be opportunities to improve the effectiveness and efficiency of the IRP Framework.

## 8.1 Cost Threshold for IRP Plan Applications

### 8.1.1 Requirements in IRP Framework

When Enbridge Gas determines that an IRP Alternative (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.

The IRP Framework established a new approval process for IRP Plans under section 36 of the *Ontario Energy Board Act, 1998*. An IRP Plan approval from the OEB operates as an endorsement of the IRP Plan, and approval of the cost consequences. The costs are then recovered, subject to a prudence review, through the clearance of the IRP Costs deferral accounts annually and/or at Enbridge Gas's next rebasing application.

An IRP Plan approval is 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. Enbridge Gas has discretion as to whether to file an IRP Plan application for amounts below this threshold or simply to proceed without advance approval.

### 8.1.2 Developments Since Release of IRP Framework

At the time the IRP Decision was released, the cost threshold for pipeline projects to require a Leave to Construct approval was $2 million, which was therefore also the cost threshold for an IRP Plan approval. An amendment to Ontario Regulation 328/03 made in 2024 now requires the OEB, on application, to exempt pipeline projects costing between $2 million and $10 million from obtaining Leave to Construct approval from the OEB, if the OEB determines that the Crown's duty to consult, if it applies in respect of the application, has been adequately discharged.[63] This change, may, therefore, have introduced some ambiguity as to whether or not IRP Plans costing between $2 million and $10 million are required to seek OEB approval under the existing IRP Framework.

The one non-pilot IRP Plan Enbridge Gas has completed (East Kingston Creekford

---

[63] O Reg 328/03, s. 3.0.1, as amended by O. Reg. 274/24.

Road project) [64] had a project cost well below $2 million, and Enbridge Gas did not request an IRP Plan approval from the OEB.

### 8.1.3 Analysis and Proposals

The OEB could consider increasing the cost threshold for when an IRP Plan approval is required from the OEB.

A higher cost threshold for IRP Plan approvals would provide Enbridge Gas with the opportunity to move more quickly on mid-size IRP Plans without requiring an upfront approval of all aspects of the IRP Plan. It would also be consistent with the general intent of the Leave to Construct regulatory change, for which the Ministry of Energy and Mines noted an expectation that the change would reduce costs and expedite timelines for the construction and expansion of low-cost pipeline projects.[65] The proposed change for IRP Plan approvals could yield similar benefits, and would ensure that IRP solutions do not face more stringent approval requirements than pipeline projects.

Cost recovery of implemented IRP Plans would continue to be addressed through the IRP Costs deferral accounts. These costs are incremental to base rates, however the IRP Costs deferral accounts have been modified to recognize offsetting amounts to reflect avoided capital cost impacts related to facilities projects that are delayed, avoided or downsized by IRP. A methodology for this calculation has not yet been finalized.[66] If the cost threshold for IRP Plan approvals is increased, there could be more project spending being recorded in these accounts without prior OEB approval that is subject to this offsetting approach. This makes it more important to ensure there is an OEB-approved approach as to how this offsetting approach will work. OEB staff recommends that Enbridge Gas's proposed approach be brought forward for review as part of Enbridge Gas's IRP Implementation Plan.

### 8.1.4 Indigenous Consultation Requirements

The existing IRP Framework requires Enbridge Gas to conduct consultation with respect to any potential impacts to Aboriginal or treaty rights in relation to proposed IRP Plans. When requesting approval for an IRP Plan or a Leave to Construct, Enbridge Gas is also required to follow the requirements in the OEB's Environmental Guidelines for the Location, Construction and Operation of Hydrocarbon Pipelines and Facilities in Ontario (Environmental Guidelines) regarding Indigenous consultation, if applicable.

---

[64] EB-2024-0125, Exhibit C, Tab 1, pp. 19-20

[65] https://ero.ontario.ca/notice/019-8562

[66] EB-2025-0064, Exhibit I.1.13-Staff

OEB staff does not propose any changes to these requirements. However, a consideration is that if an IRP Plan falls below the cost threshold for which OEB approval is required, there is no proceeding for the OEB to assess any concerns regarding potential impacts on Aboriginal or treaty rights.

OEB staff notes the following considerations:

- For Leave to Construct applications, the Ministry of Energy and Mines plays an important role in coordinating the Crown's duty to consult obligations, as described in the Environmental Guidelines, including determining whether the proposed project triggers the duty to consult, and (following delegation of the procedural aspects of consultation to the applicant), subsequently providing the applicant with a letter expressing the Ministry's view on the adequacy of Indigenous consultation based on the materials it has reviewed. The Ministry has not adopted this role for non-facility projects such as IRP Plans. For this reason, OEB staff is not proposing to replicate, for IRP Plans, the change to the Leave to Construct approval requirements that allows an applicant to request an exemption from OEB approval for projects costing between $2 million and $10 million if the OEB determines that the Crown's duty to consult, if it applies in respect of the application, has been adequately discharged.
- Impacts to Aboriginal or treaty rights may be less likely for IRP Plans than for facility projects. For Enbridge Gas's Southern Lake Huron IRP Pilot, Enbridge Gas notified Indigenous groups located in the vicinity of the pilot areas and provided its opinion that the application did not trigger the duty to consult.[67]

### 8.1.5 Discussion Questions

14. Do you support increasing the cost threshold at which IRP Plans require OEB approval, or do you have alternative proposals related to approval requirements?
15. How should the OEB address the implications of approval requirements regarding potential impacts of IRP Plans on Aboriginal or treaty rights?

[67] The OEB did not make an explicit determination on this matter. EB-2022-0335, Exhibit F, Tab 1, Schedule 3

## 8.2 Project Cost Threshold for Detailed Consideration of IRP Alternatives

### 8.2.1 Requirements in IRP Framework

For pipeline replacement and relocation projects, the IRP Framework indicates that if the cost is less than the minimum project cost that would necessitate a Leave to Construct approval, then Enbridge Gas is not required to conduct an IRP evaluation (i.e., consideration of IRP Alternatives is screened out and Enbridge Gas can proceed with a facility solution). The OEB noted 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. No such exemption exists in the IRP Framework for growth (system reinforcement to address demand growth) projects, i.e. Enbridge Gas is expected to proceed to the technical evaluation stage and consider IRP Alternatives for growth projects of any cost.

### 8.2.2 Developments Since Release of IRP Framework

The change to the Leave to Construct approval requirements discussed in section 8.1 also has implications for this section of the current IRP Framework. Specifically, it may create ambiguity as to whether Enbridge Gas is expected to consider IRP Alternatives for pipeline replacement and relocation projects costing between $2 million and $10 million. Currently, Enbridge Gas continues to apply a cost threshold of $2 million to screening replacement and relocation projects.[68]

With regards to growth-related projects, Enbridge Gas has identified that there are a large number of low-cost growth-related projects in its 2025-2034 AMP (23 discrete projects totalling $4.3 million). Under the current IRP Framework, the expectation is that technical evaluations considering IRP Alternatives would be conducted for all of these projects.

### 8.2.3 Analysis and Proposals

As it has worked through the IRP Assessment Process for low-cost growth projects, Enbridge Gas has concluded that conducting technical evaluations for growth investments with costs of less than $2 million is a resource-intensive process and does not provide benefits for IRP internal assessment processes or potential IRP implementation. Enbridge Gas has also found that IRP Plan costs to avoid this type of infrastructure investment are significantly higher than the reference facility cost. Enbridge Gas has therefore proposed screening out growth projects costing less than

[68] IRP Assessment Screening and Evaluation Guidelines

$2 million from detailed IRP evaluation.

This proposal has been discussed several times with the IRP Working Group. Based on these discussions, Enbridge Gas considered developing a simplified evaluation for growth investments but found that this would still require significant time and resources. Enbridge Gas subsequently provided the IRP Working Group with a draft of its proposed approach for screening of growth-related investments (*IRP Assessment Cost Threshold Screening of Growth Investments*) and its rationale for the $2 million exemption criterion. Views from the IRP Working Group were mixed, and several additional suggestions were provided for Enbridge Gas to consider.[69]

Based on these discussions, OEB staff is open to the possibility of making detailed technical evaluation of IRP Alternatives for low-cost growth projects optional in the updated IRP Framework. This is consistent with the IEP and Natural Gas Policy Statement, and could improve efficiency and enable Enbridge Gas to focus its IRP resources on higher-value projects where there is a greater likelihood of IRP implementation. OEB staff notes that the $2 million cost threshold proposed by Enbridge Gas is also used by the OEB in its expectations for consideration of non-wires solutions for electricity distributors.[70] OEB staff also recommends that Enbridge Gas file its *IRP Assessment Cost Threshold Screening of Growth Investments* (including any updates in response to the most recent discussion with the IRP Working Group) as part of this IRP Framework review to allow the OEB and other stakeholders to consider Enbridge Gas's full rationale before making a determination on this issue. Should a cost threshold be established, OEB staff notes that a gas distributor would not be prevented from considering IRP Alternatives for projects below the cost threshold, however this would be at the distributor's discretion.

With regards to pipeline replacement and relocation projects, OEB staff recommends that the $2 million screening cost threshold continue to apply. For projects costing more than $2 million, OEB staff believe that the incremental effort to evaluate IRP Alternatives is justified due to the higher project cost.

Table 9 summarizes the current requirements for consideration of IRP Alternatives and subsequent approval requirements.

---

[69] See meeting minutes from IRP Working Group meeting #43, item 2.The draft document referred to was provided to Working Group members in advance of this discussion on a confidential basis.

[70] Above this cost threshold, electricity distributors are required to document their consideration of non-wires solutions, and follow the Benefit-Cost Analysis (BCA) Framework; below this cost threshold, electricity distributors may use existing, alternative cost-effectiveness or decision-making protocols, or the BCA Framework at their discretion. See section 2.2 of the BCA Framework.

### Table 9. IRP Consideration and Approval Requirements Based on Project Cost

| Project Cost[71] | Current IRP Framework/Leave to Construct Requirements |
|---|---|
| < $2 million | • Consideration of IRP Alternatives required for growth projects, but not for pipeline replacement/relocation projects.<br>• OEB approval not required for facility solution (if selected as preferred option to address need) nor IRP Plan (if selected). |
| $2 million - $10 million | • Consideration of IRP Alternatives is required for growth projects, and is ambiguous for pipeline replacement/relocation projects.<br>• If facility (pipeline) solution is selected for growth projects, Leave to Construct approval is required, but exemption may be requested from the OEB. The only determination to be made by the OEB is that duty to consult has been adequately discharged in relation to the project.[72]<br>• If facility (pipeline) solution is selected for replacement/relocation project, Leave to Construct approval is required if diameter of the line is increased, or the acquisition of additional land or authority to use additional land is necessary, but exemption may be requested from the OEB. The only determination to be made by the OEB in such case is that duty to consult has been adequately discharged in relation to the project.<br>• If IRP Plan selected, OEB approval potentially required (ambiguous). |
| > $10 million | • Consideration of IRP Alternatives required.<br>• If facility solution selected, OEB Leave to Construct approval required for growth projects, and for pipeline replacement/relocation projects if diameter of the line is increased, or the acquisition of additional land or authority to use additional land is necessary.73<br>• If IRP Plan selected, OEB approval required. |

[71] Certain conditions other than cost can also trigger the need for a Leave to Construct approval of a pipeline (length, pipe size or operating pressure) under section 90(1) of the *Ontario Energy Board Act, 1998*.

[72] According to Ontario Regulation 328/03

[73] For pipeline replacement/relocation projects that would require Leave to Construct approval only because the acquisition of additional land or authority to use additional land is necessary, the OEB may also determine, on application, that Leave to Construct approval is not required because the pipeline replacement/relocation is being requested by a third party, any additional land required for the relocation or reconstruction is under the requesting person's control, and the cost of the relocation or reconstruction is to be paid for wholly or partly by the requesting person, and the OEB determines that the Crown's duty to consult, if it applies in respect of the application, has been adequately discharged.

### 8.2.4 Discussion Questions

16. Do you support introducing a cost threshold for mandatory evaluation of IRP Alternatives for growth-related projects? Why or why not?

## 8.3 Three-Phase Discounted Cash Flow-Plus Economic Evaluation Test

### 8.3.1 Requirements in IRP Framework

The IRP Framework approved a three-phase DCF+ test as the economic evaluation test used to compare the cost-effectiveness of IRP Alternatives and Facility Alternatives:

- 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.

The IRP Framework places primary importance on phase 1 results, noting that 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 IRP Framework also required Enbridge Gas to study improvements to the DCF+ test, in consultation with the IRP Working Group and to file an enhanced DCF+ test for approval as part of the first non-pilot IRP Plan.

### 8.3.2 Developments Since Release of IRP Framework

The IRP Working Group has held extensive discussion on the DCF+ test, including a detailed report released in 2023.[74] The IRP Working Group (including Enbridge Gas) has subsequently resolved many methodological issues, but has been unable to reach consensus on some aspects of the test.

Based on these discussions, Enbridge Gas has developed a DCF+ Supplemental

---

[74] *Use of the Discounted Cash Flow-Plus Test in Integrated Resource Planning*, IRP Working Group, May 30, 2023

Guide.[75] This Guide presents enhancements to the DCF+ Test, and also explains methodological considerations, defines how to calculate specific benefits and costs for proposed solutions, and presents general considerations and notable challenges regarding alternative assessments.

The OEB has not to date considered (or approved) the enhanced DCF+ test, but Enbridge Gas has begun to apply its enhanced methodology (as described in the DCF+ Supplemental Guide) to economic evaluations for projects in its AMP, as discussed in section 3.2.

### 8.3.3 Analysis and Proposals

OEB staff believes that the remaining aspects of non-consensus on the DCF+ test are best addressed through adjudicative review. Enbridge Gas and the IRP Working Group generally agree with this.

Key points of non-consensus[76] are:

- Whether and how some form of social cost of carbon should be part of phase 3 of the DCF+ test. This is particularly relevant now that no Federal Carbon Charge for the economic cost of carbon is included in phase 2 of the DCF+ test.
- The approach and methodology to considering broader economic impacts (such as jobs and Gross Domestic Product impact) in phase 3 of the DCF+ test.

While not a significant focus of IRP Working Group discussion to date, OEB staff notes that the jurisdictional scan (appendix B) also recommended that social and equity value streams be calculated alongside typical equipment and avoided costs, assuming this aligns with policy objectives. The IRP Working Group (including Enbridge Gas) has generally been supportive of including a customer non-energy benefit adder in the DCF+ test, where appropriate. Whether and how this customer non-energy benefit adder might apply, and whether the non-energy benefit adder or other aspects of the DCF+ test might be modified to account for equity considerations (e.g., if benefitting low-income customers or on-reserve First Nation communities) could also be considered in the DCF+ test review.

Enbridge Gas has indicated that (as per the current IRP Framework), it will bring forward its enhanced DCF+ test methodology for approval as part of its first non-pilot IRP Plan; however, OEB staff proposes that Enbridge Gas should be required to do so as part of Enbridge Gas's IRP Implementation Plan (chapter 5), if there is no prior

---

[75] Still in draft form and shared with the IRP Working Group on a confidential basis.

[76] See Enbridge Gas materials for IRP Working Group meeting #57, slide 17.

opportunity to review the DCF+ test in the context of an IRP Plan to address a specific system need. The reason for this is that Enbridge Gas is already using the DCF+ test (with the methodology it has adopted) in its IRP Assessment Process, where it has implications for Enbridge Gas's decisions on how to address system needs.

Related to the DCF+ test, OEB staff proposes that the OEB could consider whether the importance placed on different phases of the DCF+ test should be adjusted in the updated IRP Framework. One option that could be considered is giving preference to the solution (IRP Alternative or Facility Alternative) that scores best on phase one plus phase two of the DCF+ test, rather than phase one alone (as is currently the case).

- Favouring phase one (referred to in Enbridge Gas's draft DCF+ Handbook as the "Relative Rate Perspective") selects the option to address a system need that has the best results considering the incremental costs and revenues that impact OEB-approved utility rates for Enbridge Gas customers.
- Favouring phase one plus phase two (the addition of these two phases is referred to in the draft DCF+ Handbook as the "Total Enbridge Gas Customer Perspective") selects the option to address a system need that has the best forecast results for all Enbridge Gas customers (in the aggregate), taking into account both the phase one costs and benefits captured in rates, plus additional impacts for Enbridge Gas customers participating in the IRP Alternative outside of rates, such as commodity cost savings or incremental equipment costs paid for by participants.

The result of the current IRP Framework's emphasis on phase one results is that it is very difficult for energy efficiency IRP Alternatives to be chosen as the most cost-effective option, as their major benefit stream (savings in customer commodity/fuel costs) is excluded.

These considerations were taken into account in the original IRP Framework proceeding. Parties favouring the primacy of phase one DCF+ results emphasized the importance of the economic test selecting solutions that benefited all customers paying postage stamp rates, noting that other approaches to cost-effectiveness could lead to customers not directly participating in an IRP Alternative paying more through rates for the IRP Alternative than they would have paid for a pipeline solution.[77]

However, as subsequent experience has shown (discussed in section 3.2), the opportunities for IRP Plans to pass the technical evaluation stage and even reach the economic evaluation stage for system needs in Enbridge Gas's AMP are rather limited.

[77] EB-2020-0091 Decision and Order, p. 53

Thus, changing the importance placed on the phases of the DCF+ test is unlikely to impose significant costs on non-participants, but it would provide more opportunities for IRP implementation, improving outcomes for Enbridge Gas customers (in the aggregate), and providing opportunities for Enbridge Gas to learn and get better at doing IRP. OEB staff believes this is a reasonable trade-off.

An alternative approach that could also be considered, given that the enhanced DCF+ test will be brought forward subsequently for OEB approval, is for the updated IRP Framework to remove any language related to the relative importance of the three phases, with that issue to be considered in the subsequent adjudicative review of the enhanced DCF+ test.

### 8.3.4 Discussion Questions

17. Should the importance placed on the different phases of the DCF+ test be adjusted? Why or why not?
    a. Should this issue be considered as part of the process to update the IRP Framework, or as part of a subsequent proceeding (e.g., as part of the first IRP Implementation Plan proceeding)?
18. Are there other changes to the cost-effectiveness approach used for IRP that should be incorporated into an updated IRP Framework (as opposed to subsequently considered through adjudicative review of the enhanced DCF+ test)? If so, what?

# APPENDIX A: CONSOLIDATED QUESTIONS TO STAKEHOLDERS

**Chapter 4:**

1. What implications does the current public policy environment have for an evolved IRP Framework and the OEB's IRP-related expectations of natural gas distributors?

**Chapter 5:**

2. Which of the procedural options, if any, for updating the IRP Framework do you prefer, and why?
3. Should any updated IRP Framework be specific to Enbridge Gas, or applicable to all rate-regulated gas distributors?
4. Does the level of detail in the current IRP Framework strike an appropriate balance between:
   (a) defining the OEB's expectations and providing regulatory certainty on IRP
   (b) Allowing for flexibility and evolution in Enbridge's approach to IRP implementation?
   a. Would more or less detail be preferable in an updated IRP Framework?
5. Do you support the OEB staff proposal for an IRP Implementation Plan? What modifications, if any, to this proposal, and to the annual reporting approach, would you suggest?
   a. How frequently should an IRP Implementation Plan be developed and reviewed? Should the IRP Implementation Plan be reviewed as part of, or separately from, Enbridge Gas's rebasing application?
6. How do you see the role of the IRP Working Group evolving under an updated IRP Framework? Do you agree with OEB staff's proposed approach? Why or why not?

**Chapter 6:**

7. Do you support the definition of "innovation-related IRP proposals" as proposed by OEB staff? Why or why not?
   a. Are there additional elements or considerations you believe should be emphasized or included to better define the scope of innovation-related IRP proposals?
8. Which, if any, of the four proposed oversight mechanisms for innovation-related proposals do you support and why?

   a. What modifications to the proposed oversight mechanisms, if any, would you suggest?

9. What assessment criteria would best support value-driven innovation? Do you agree with the five considerations proposed by OEB staff? If not, what changes would you propose?

**Chapter 7:**

10. Are you in favour of expanding electrification as an eligible IRP Alternative beyond the current pilots? Why or why not?

11. Is there value in a pilot that includes electrification as an alternative to new customer connections (which is not part of the existing Southern Lake Huron pilot or the system pruning pilot)?

12. Are there any legal considerations or limitations relevant to the OEB's ability to approve funding for electrification or other non-gas IRP Alternatives under the *OEB Act* (natural gas rates)?

13. Do you have suggestions regarding the approach to identifying electricity system impacts triggered by an electrification IRP Alternative, or the approach to quantifying electricity system impacts in cost-effectiveness testing?

**Chapter 8:**

14. Do you support increasing the cost threshold at which IRP Plans require OEB approval, or do you have alternative proposals related to approval requirements?

15. How should the OEB address the implications of approval requirements regarding potential impacts of IRP Plans on Aboriginal or treaty rights?

16. Do you support introducing a cost threshold for mandatory evaluation of IRP Alternatives for growth-related projects? Why or why not?

17. Should the importance placed on the different phases of the DCF+ test be adjusted? Why or why not?

   a. Should this issue be considered as part of the process to update the IRP Framework, or as part of a subsequent proceeding (e.g., as part of the first IRP Implementation Plan proceeding)?

18. Are there other changes to the cost-effectiveness approach used for IRP that should be incorporated into an updated IRP Framework (as opposed to subsequently considered through adjudicative review of the enhanced DCF+

test)? If so, what?

**Overall:**

19. Do you have any other comments or suggestions regarding changes to the IRP Framework?

# APPENDIX B: JURISDICTIONAL ANALYSIS

Table 10 presents IRP practices in other jurisdictions, as applicable to some of the key topics in this discussion paper, extracted from a jurisdictional scan completed by external consultant DNV.[78] The jurisdictional scan was intended to provide Enbridge Gas, the IRP Working Group and the OEB with a foundational understanding of system pruning approaches, best practices and lessons learned, to assist in the development of a potential system pruning framework and pilot in Ontario. While developed in response to system pruning, the jurisdictional scan also included information related to NPA programs, which are more prevalent and adjacent to system pruning. The three non-Ontario jurisdictions selected for review in this jurisdictional scan and shown in the table below are generally also considered to be leaders in NPAs/IRP.[79]

**Table 10. IRP Practices in Other Leading Jurisdictions**

| | **Ontario** (initial framework)[80] | **New York** | **California** | **Massachusetts** (draft framework)[81] | **Common** (among jurisdictions) |
|---|---|---|---|---|---|
| **Regulatory Framework and Obligations** | • Utility-specific framework for Enbridge, used as a resource to guide EPCOR.<br>• Specific milestones and requirements (e.g., annual reporting, clearance of IRP Costs deferral accounts, establishing a working | • Statewide decarbonization goals transforming the way gas utilities approach planning and capital projects; Climate Leadership and Community Protection Act targets statewide | • At forefront of clean energy policy in US, leveraging regulations and incentives to decarbonize energy systems and manage transition away from natural gas.<br>• California Public Utilities Commission (CPUC) | • Limited regulatory requirement governing NPAs and system pruning, but gas utility required to demonstrate NPA due diligence on new gas infrastructure projects (submitted for regulatory review) and maintains strong | • Jurisdictional requirements shape legislative, regulatory, and utility processes.<br>• Primary driver of NPA activities in reviewed jurisdictions is a policy framework centered |

[78] System Pruning Jurisdictional Scan, August 15, 2025, DNV.

[79] Colorado, Quebec, and Zurich are additional jurisdictions considered in the jurisdictional scan.

[80] Added for comparative purposes – Ontario's IRP Framework was not reviewed as part of the jurisdictional scan.

[81] https://img1.wsimg.com/blobby/go/abf00124-5f5f-4755-92c3-e723c88d649d/downloads/c1ccf822-0412-405f-baf5-96afdea3992f/January%2015%202025%20NPA%20Framework.pdf?ver=1743422390855

| | **Ontario**<br>(initial framework)[80] | **New York** | **California** | **Massachusetts**<br>(draft framework)[81] | **Common**<br>(among jurisdictions) |
|---|---|---|---|---|---|
| | group).<br>• No set process for reviewing framework or requirement for utility to develop forward-looking IRP plan aligned with Framework. | greenhouse gas emissions reduction of 40% by 2030 and 85% by 2050.<br>• To support emission reduction goals, New York Department of Public Service opened a regulatory proceeding to modernize the gas system planning process, increase stakeholder engagement, and expand the portfolio of projects to include NPAs.<br>• NPA framework has three components: 1) identify projects, 2) reduce utility disincentives, and 3) recover project costs.<br>• NPA funding includes ratepayer funds (via rate case process) and non-ratepayer funds (e.g., New York State Energy Research and Development Authority's clean heat program and the | regulates electric and gas sectors and oversees investor-owned utilities like Pacific Gas and Electric (PG&E)<br>• Key policies include elimination of gas line extension allowances and regulatory oversight through General Order 177 (requiring large, environmentally impactful gas projects to obtain Certificate of Public Convenience and Necessity before construction) to prioritize safety, equity, and cost-effectiveness in gas infrastructure planning.<br>• CPUC requires utilities to file an annual report on any planned gas investments (projects >$75M require CPUC approval); this provides transparency on infrastructure projects and ensures alignment with state's transition away from gas.<br>• CPUC recommends that gas utilities evaluate all viable NPAs, but has not adopted a uniform, statewide definition of what qualifies as an | focus on DSM and NPA programs and prospects.<br>• D.P.U. 20-80 landmark piece of regulation for energy providers; sets new trajectory for natural gas in the state and guiding gas utilities to achieve net-zero greenhouse gas emissions by 2050; order requires utilities to submit climate compliance plans for regulatory approval on how they would comply with achieving net-zero by 2050. Plans must be submitted every 5 years to show movement towards the net zero target.<br>• Gas system enhancement program legislation caps program spending at 1.5% of utilities' total annual revenue, increased to 3% but will continue to decrease to 2% in 2026 and 1.5% in 2027. Allows spending up to 3% for NPAs.<br>• Through DPU order 20-80, gas distributors tasked to engage with stakeholders to develop an NPA framework; gas distributors established a working group and drafted | around climate and equity.<br>• When regulatory bodies have taken a more direct and stringent approach to directing utilities to design and adopt system pruning and NPA programs, more customers have been served, and utilities have been able to move more quickly to design and implement programs that can scale. |

| | Ontario (initial framework)[80] | New York | California | Massachusetts (draft framework)[81] | Common (among jurisdictions) |
|---|---|---|---|---|---|
| | | Inflation Reduction Act).<br>• NPA framework is a component of the long-term gas planning process; regulatory requirements to adjust for NPAs in 20-year demand forecast<br>• Commission allows some exemptions, but each utility is required to file NPA suitability criteria process along with its long-term gas system plans (filed every 3 years) for review and approval to pursue NPAs.<br>• Utilities submit periodic NPA reports to Department of Public Service describing its NPA efforts including opportunities considered, investigations conducted, customer responses, incentives, and expenditures. | NPA.<br>• California Energy Commission (CEC) plays key role in statewide energy planning; responsible for forecasting and assessing energy trends in California; publishes Integrated Energy Policy Report which evaluates energy system performance and trends; manages programs like Equitable Building Decarbonization Program which funds electric heat pumps for low-income and disadvantaged communities; works with CPUC and other state agencies to ensure gas system's alignment with California's decarbonization policies.<br>• Legislation and regulation make it clear that utilities need to develop programs towards system pruning and decarbonization; climate legislation, equity metrics, and elimination of gas system expansion helped to provide utilities with a structure to develop site identification tools and screening criteria. | an NPA framework shared with stakeholders for review and feedback Jan 2025. The following types of projects were identified as relevant and feasible for NPA review:<br>• Gas System Enhancement Program<br>• Reliability- Capacity<br>• Reliability- Replacement<br>• Gate station & regulator station<br>• Liquified natural gas/Liquified propane gas<br>• Resiliency (ability to adapt to significant disruptions)<br>• New customer requests<br>• Department of Transportation/Municipal pipe relocation requirements<br>• Master meter compliance | |

| | **Ontario**<br>(initial framework)[80] | **New York** | **California** | **Massachusetts**<br>(draft framework)[81] | **Common**<br>(among jurisdictions) |
|---|---|---|---|---|---|
| | | | • As gas demand declines, utilities exploring financial mechanisms, electrification incentives, and coordinated planning with electric providers to ensure equitable and efficient transition through gas system pruning, infrastructure modernization, and NPAs to reduce reliance on fossil gas while maintaining reliability.<br>• Some key bills/orders/rules: Senate Bill 1221 requires utilities to map and commission to prioritize segments of gas distribution system for decommissioning; CEC 2022 Building Energy Efficiency Standards encourages use of electric heat pump for space and water heating in new homes, implements electric-ready requirements, expands solar photovoltaic and battery storage standards for commercial buildings effective Jan 1/23; California Energy Code requirement for new homes to have electric appliances (including heating and cooking) instead of gas | | |

| | **Ontario** (initial framework)[80] | **New York** | **California** | **Massachusetts** (draft framework)[81] | **Common** (among jurisdictions) |
|---|---|---|---|---|---|
| **Approach to Pilots and Innovation-Related Proposals** | • No mention or definition of "innovation" in the framework.<br>• Expectations established in the Framework for the pilot(s), with funding contingent on approval of the pilot application.<br>• Pilots and/or innovation-related proposals require OEB approvals; applications are expected to include information similar to non-pilot IRP plans to avoid/defer traditional pipeline infrastructure; though certain criteria (e.g., cost-effectiveness and meeting a system need) may not be required, but this is not explicitly stated in the framework. | • In 2020, New York Department of Public Service directed gas utilities to undertake one to five thermal network pilot projects. As of July 2024, 12 projects worth ~$880M across various gas utilities in development or advanced stages of investigation.<br>• ConEd in early planning stages and has not broken ground on 3 proposed pilots covering a wide array of customers and building types. Identified challenges related to project siting, stakeholder coordination, and need for expanded customer incentive layering; difficulty in trying to tackle too many variables at once. Recommends taking baby steps to identify learnings along the way; importance of | • Funds research and development and approves pilot expenses through the regulatory body and CEC.<br>• CEC funds the targeted building electrification and gas system decommissioning pilot project in Northern California, leveraging PG&E's tool to identify high potential NPA projects; project's interim report, "Strategic Pathways and Analytics for Tactical Decommissioning of Portions of Gas Infrastructure in Northern California" highlights key integrated energy planning considerations, including the fact that targeted electrification and NPA pilots should leverage integrated planning to inform the development of regulatory frameworks for deploying these solutions at scale.<br>• Key learnings from pilot projects have informed best practices for programs offered today. For example:<br>  • PG&E's early pilot efforts revealed that simply | • Utilities are undertaking targeted electrification pilots and geothermal pilots, but this has been outside of and before the NPA framework. Each gas distribution company is to work with relevant electric distribution company to study the feasibility of piloting a targeted electrification project in its service territory.<br>• Eversource's geothermal pilot is up and running emphasizing the importance of community engagement, buy-in, and incentivizing customers for both their time and risk of taking on something new. Clear communication, opportunity for feedback, and expansive education efforts underpin these projects. | • Jurisdictions that deployed early pilot programs reported significantly better outcomes, allowing them to refine engagement strategies, infrastructure planning, and regulatory planning, and regulatory filings before committing to large-scale efforts.<br>• Programs that incorporated iterative learning loops between pilot results and full program design achieved faster regulatory approvals, higher customer satisfaction rates, and better financial performance. |

| | **Ontario** (initial framework)[80] | **New York** | **California** | **Massachusetts** (draft framework)[81] | **Common** (among jurisdictions) |
|---|---|---|---|---|---|
| | | continuing to engage with customers, maintaining strong communication channels, and making clear all steps, laws and regulations, and breakdown potentially confusing language.<br>• Lessons learned from pilots directly influenced subsequent regulatory filings and project approval processes, streamlining later pruning efforts.<br>• In 2022, Utility Thermal Energy Network and Jobs Act 151 signed to advance utility thermal network development by removing legal barriers; act supports pilot developments and directs Department of Public Service "to develop a regulatory structure that scales affordable and accessible building electrification, | offering financial incentives without extensive education, contractor support, and administrative assistance was insufficient to drive meaningful participation. These insights led PG&E to redesign its engagement model, layering financial, technical, and logistical support into a holistic customer transition service.<br>• Similarly, PG&E's Zonal Electrification Equity Pilot tested geospatial targeting of neighborhoods based on electric grid readiness, customer demographics, and building stock characteristics; pilot revealed unanticipated bottlenecks like transformer upgrades and multi-year permitting delays, which informed future resource planning and budget allocations. Zonal Electrification Equity Pilot allowed PG&E to trial enhanced | | |

| | **Ontario** (initial framework)[80] | **New York** | **California** | **Massachusetts** (draft framework)[81] | **Common** (among jurisdictions) |
|---|---|---|---|---|---|
| | | protects the interest of customers, and prioritizes the development of a well-trained, highly skilled labor force that will be needed to support the development of new thermal energy network projects."<br>• Utilities like National Grid used third party requests for proposals to seek delivery of demand reduction NPAs vs. utility-run programs; yielded mixed results as some Request for Proposals had insufficient interest or received bids that were not cost-effective.<br>• New York State Electric and Gas proceeding with Lansing NPA consisting of 5 individual projects. | customer support services, such as contractor pre-qualification programs and streamlined permit navigation assistance, which later became standard in broader deployment efforts. | | |

| | Ontario<br>(initial framework)[80] | New York | California | Massachusetts<br>(draft framework)[81] | Common<br>(among jurisdictions) |
|---|---|---|---|---|---|
| **Electrification as an IRP Alternative** | • Out of scope as an IRP Alternative; electrification explicitly excluded from original framework but decision notes that this may evolve as integrated energy planning matures.<br>• Since release of the IRP framework, there have been significant developments including the inclusion of electric heat pumps in DSM programming, consideration of electrification in the Southern Lake Huron IRP Pilot, and new expectations for coordinated gas and electricity infrastructure planning in the IEP. | • Leaking and leak-prone pipelines prioritized for replacement with NPA (potentially includes electrification and pipe retirement) in the project planning process based on evaluation criteria like the project cost and timelines to implement.<br>• Scale of electrification has not been large enough to require substantial electric planning; coordination for electrification projects has largely been undertaken by combined gas/electric utilities to improve planning and implementation, but there are still concerns over lack of clarity regarding cost recovery of stranded assets and mechanisms to capture lost revenue opportunities.<br>• A gas/electric utility in | • California gas utilities exploring transition away from pipelines as maintaining California's aging natural gas distribution system is becoming increasingly expensive and the state's climate goals demand sharp reduction in gas combustion to meet emission targets. Therefore, targeted building electrification and strategic gas decommissioning offers a viable and potentially cost-effective alternative to continued pipeline maintenance. For example:<br>  • PG&E exploring electrification opportunities on radial feeds where several miles of pipeline serve a small # of customers, removing underutilized or inactive pipelines, downrating lines, and eliminating projects. These areas for potential electrification show cost saving potential, as it is expensive to serve these small populations with existing, aging pipe.<br>  • PG&E's electrification | • Significant funding and incentives for equipment used in electrification scenario; funding sources would be leveraged through MassSave energy efficiency program.<br>• Under DPU 24-194, National Grid submitted a Targeted Electrification Demo implementation plan to the regulator for review and approval. To understand customer satisfaction, the evaluation plan will track metrics associated with customer interest, response rates, marketing strategies, costs of home electrification, participant experience and satisfaction, and bill impacts. These will be conducted by a third-party evaluator to mitigate bias.<br>• As part of the proposed NPA framework, "Step Zero" review developed by electric distribution system operators will determine if the electric system can safely and reliably serve the additional load, and the level of investment needed. | • Most jurisdictions consider electrification, energy efficiency, demand response, and thermal networks as eligible for system pruning or NPAs.<br>• It appears strategic decommissioning of gas assets as a general practice is still in its infancy.<br>• Most successful cross-utility engagements were facilitated through an oversight agency or legislation that went beyond a mandate to collaborate. |

| | **Ontario** (initial framework)[80] | **New York** | **California** | **Massachusetts** (draft framework)[81] | **Common** (among jurisdictions) |
|---|---|---|---|---|---|
| | | New York notes has > 20 internal teams working on system pruning and NPA matters.<br>• Not yet much coordination across separate electric and gas utilities; but as part of the gas system planning process, gas-only utilities will refer customers to the electric utility in areas identified as suitable for NPA to pursue electrification measures.<br>• Electrification is combined with weatherization in system pruning proposals, where applicable.<br>• Utility Thermal Energy Network and Jobs Act 151 supports development of regulatory structure to scale affordable and accessible building electrification. | efforts include: 1) Alternative Energy Program which avoids or reduces gas spending through more cost-effective alternatives, using an NPV approach, and 2) Zonal Electrification Equity Pilot which focuses on identifying and demonstrating strategies for zonal electrification projects located in disadvantaged communities.<br>• PG&E has completed 88 targeted electrification projects, decommissioned 22 miles of transmission pipe, and converted 105 customers from gas.<br>• PG&E's Gas Investments for the Future program actively pursues cost-effective electrification as an NPA to planned gas investments since 2018, reaching NPA buy-in agreements with ~45% of identified customers.<br>• CEC set new requirements | | |

| | **Ontario** (initial framework)[80] | **New York** | **California** | **Massachusetts** (draft framework)[81] | **Common** (among jurisdictions) |
|---|---|---|---|---|---|
| | | | for new homes to have electric appliances (including heating and cooking) instead of gas, signaling a shift towards electric options for new construction.<br>• PG&E emphasized need for tight internal coordination across gas decommissioning team, electric planning groups, and customer engagement programs; early pilot projects revealed that misaligned timelines between infrastructure upgrades and customer outreach could cause costly delays and erode customer trust in the program. PG&E created cross-functional electrification project teams with authority to manage planning, communications, and service transitions in a unified way.<br>• PG&E notes statutory 'obligation to serve' is a barrier to large-scale electrification as utilities are mandated to provide service upon request; this prevents gas utilities from ceasing service to customers unwilling to transition from gas; PG&E is exploring | | |

| | Ontario<br>(initial framework)[80] | New York | California | Massachusetts<br>(draft framework)[81] | Common<br>(among jurisdictions) |
|---|---|---|---|---|---|
| | | | legislative support to enable broader electrification efforts. | | |
| **Assessment Process/ Scope of Consideration** | • Consideration of IRP Alternatives required for most system needs, with specific screening criteria; technical evaluation to confirm if IRP Alternatives can provide required peak demand reduction.<br>• IRP plan approval is mandatory if cost of IRP plan exceeds a minimum cost threshold that would necessitate a Leave to Construct approval for a pipeline | • New customer request for gas service exempt from NPA analysis.<br>• Gas Planning Order approved dual-track (comprehensive and expedited) approach to evaluate NPAs based on project cost and timeline; comprehensive review by Department of Public Service required for large projects with costs >$2M and requiring >24 months to implement; commission order acknowledged projects that address threats to public safety, system reliability, or customer requests are exempt from the NPA process.<br>• Gas planning process is used by utilities to | • Utilities must evaluate NPA and seek approval for certain gas infrastructure investments exceeding specified cost thresholds.<br>• State regulations require NPA analysis for projects with significant air quality impacts. This policy shift aligns with CPUC's broader objective of reducing stranded gas assets and prioritizing NPAs in future infrastructure planning.<br>• PG&E uses a geospatial electrification tool to identify candidate sites for NPAs; tool evaluates potential areas for zonal electrification using data like customer income, prevalence of renters, geographic risks, and electric capacity.<br>• Every gas utility has a Distribution Integrity Management Program, which pre-emptively replaces distribution pipeline segments based on | • Categorization of all types of capital projects as suitable/ unsuitable for NPA consideration.<br>• New customer connection requests are in scope for NPA consideration, and gas distribution companies are required to inform and educate potential customers on non-gas options.<br>• Once an NPA proceeds to the implementation stage, gas distribution companies will not accept new gas connections in the discrete NPA project area.<br>• Initial Viability Testing stage to identify high-value projects where NPAs are most likely to be viable.<br>• Gas system feasibility review to determine if the gas system can function safely without the investment the NPA is looking to displace, plus electric system review, if appropriate. | • California, Mass., and New York prioritize disadvantaged communities for more immediate transition away from natural gas; intended for a more equitable energy transition and to avoid overburdening already burdened household knowing that if and when customers leave the gas network, maintenance of the gas system is spread across fewer ratepayers, resulting in increased costs for individuals. This is more likely to be borne by low-income customers without the capital to transition away from gas on their own.<br>• Nearly all infrastructure projects require some level of NPA analysis across jurisdictions. Projects that are required to maintain system safety and reliability are exempt from the analysis |

| | Ontario (initial framework)[80] | New York | California | Massachusetts (draft framework)[81] | Common (among jurisdictions) |
|---|---|---|---|---|---|
| | | identify NPA opportunities; screening process targets aging gas infrastructure and assets that are significantly depreciated, in some cases 50-80 years; inventory of the current system is taken, and leak-prone pipes are prioritized for NPA investigation. The type of asset (radial or one-way feeds), number of customers impacted, types of buildings, gas/electric usage, and a benefit-cost analysis are all considered. | assessed risk; CPUC staff recommend prioritizing pipeline repair, replacement, or decommissioning based on risk scores; risk calculation based on utility-specific formulas using inputs like soil conditions, nearby past leaks, pipeline material, and pipeline age; the product of the likelihood of failure and the consequence of failure is the risk score. Standardizing this approach across utilities through the Risk-Based Decision-Making Proceeding (R.20-07-013) is under consideration.<br>• CPUC advises against using depreciation costs to prioritize pipeline decommissioning due to accounting complexities. Cost, safety metrics, pipeline risk, and forecast replacement costs are considered sufficient. | • If there are too many projects to implement, prioritize based on (in order): location in environmental justice communities, net avoided greenhouse gas emissions, amount of avoided capital | process, as are those with insufficient lead time to implement an NPA. Level of regulatory review varies across jurisdictions and may depend on size of the capital expenditure or the reason for investment. |
| **Economic Evaluation and Cost Recovery** | • A 3-phase benefit cost test (DCF+ test) used to compare the economic viability of IRP Alternatives vs. facility projects.<br>• Framework allows | • Benefit-cost analysis (BCA) framework adopted societal cost test as primary BCA method.<br>• Each utility is required | • Cost-effectiveness test not established for gas decommissioning; not settled on types of benefits and costs or discount rate to be used; NPV cost test generally used to compare cost of a | • Cost-effectiveness tests established for energy efficiency and demand response program; Department of Public Utilities directs gas utilities to conduct a BCA for NPAs; | • Cost-effectiveness testing remains unique to each utility (though there are some similarities in benefit and cost inputs). However, the test should ensure that social and |

| | **Ontario**<br>(initial framework)[80] | **New York** | **California** | **Massachusetts**<br>(draft framework)[81] | **Common**<br>(among jurisdictions) |
|---|---|---|---|---|---|
| | consideration of all 3 phases but indicates a strong preference for the solution that scores highest in phase 1 (rate impact). Phase 2 captures customer benefits and Phase 3, societal impacts. | to provide a BCA of each alternative, consideration of bill impacts, NPV of estimated costs, and emission impacts.<br>• Larger project evaluation includes a BCA; smaller projects evaluated using a streamlined economic and technical evaluation.<br>• Allows NPA costs to be recovered from gas customers over a shorter period of 10 to 20 years, rather than 30+ years for traditional gas assets. To reduce disincentives to pursue NPAs, regulators allow gas utilities to incorporate lost revenues and rate adjustment mechanisms to balance the impact on ratepayers and utilities. | pipe plan (e.g., equipment and maintenance) vs. electrification or pruning alternatives.<br>• Costs measured based on whether they are energy efficiency technologies (covered by a different mechanism) or not; if not energy efficient, costs are recovered through rate-setting with operating expenses recovered without a markup for profit and capital expenses are depreciated over time and utilities are allowed to earn a return on investment.<br>• Regulator allowed to deem whether a utility can recover additional costs due to early retirement and underappreciated value of gas assets, including the amount and period of recovery for the utility. | NPA working group proposed cost effectiveness test that covers 4 main areas: participant cost test, gas and electric rate impact measurement, and total resource cost test with proposed benefit and cost variables for NPA analysis. Discussions are still ongoing, but clear that the state is looking to account for as many variables as possible impacted by NPAs, and not just incremental costs of capital and labor.<br>• Utilities will pursue a viable, cost-effective NPA (defined as an NPA with BCA tests ≥1); however, utilities may consider proceeding with an NPA when one or more BCAs are negative if remaining BCAs are positive, project is not cost-prohibitive, and other external circumstances make the NPA the more favorable option. | equity considerations are treated at the same level as typical equipment and avoided costs. |

| | Ontario<br>(initial framework)[80] | New York | California | Massachusetts<br>(draft framework)[81] | Common<br>(among jurisdictions) |
|---|---|---|---|---|---|
| **Actual Projects/ Results to Date** | • Despite notable investment in time and resources, progress on IRP has delivered limited-to-no savings for ratepayers.<br>• East Kingston Creekford Road reinforcement project and Southern Lake Huron pilot are the only approved or implemented IRP Alternatives | • Small system pruning projects completed by Con Ed and Central Hudson<br>• Utilities encountered regulatory uncertainty regarding cost recovery for NPA projects; although regulators encouraged electrification and decarbonization, there was limited clarity on how stranded gas infrastructure costs would be allocated across customer classes; utilities expressed concern that without clear cost recovery frameworks, pruning projects risked shifting significant financial burdens onto remaining gas customers, raising equity and affordability issues. | • Various utilities completed >100 system pruning and NPA projects in the past 3-5 years; majority success in small 1-3 building projects mostly in residential areas; PG&E's early pilot efforts revealed that simply offering financial incentives without extensive education, contractor support, and administrative assistance was insufficient to drive meaningful participation.<br>• Although decarbonization goals strongly supported electrification, regulatory treatment of decommissioned assets and recovery of lost gas revenues remained ambiguous; as such, PG&E's early projects revealed that failure to pre-negotiate regulatory approvals around stranded costs and reallocation strategies led to delays in project timelines and increased stakeholder opposition. | • No system pruning or NPA projects have been completed; this is not due to a lack of interest as much effort has been put in laying a strong foundation to meet the aggressive climate legislation and targets to reduce greenhouse gas emissions and to transition away from natural gas. This includes the formation of a cross-utility stakeholder working group to design a statewide framework for NPAs.<br>• Collaborative NPA framework development process identified the importance of cross-electric and gas utility planning to understand both gas and electric system impacts of NPA proposals.<br>• Some initial concern from stakeholders that the draft NPA framework is likely to avoid very little capital expenditure, and that stronger intervention is needed to move customers off gas.<br>• One area it has seen | • Jurisdictions testing methodologies, identifying best practices, and moving towards approaches that work (tailored to the unique nature of their jurisdiction) through pilots, demonstration projects, and stakeholder working groups.<br>• California and New York have completed system pruning and NPA projects; Mass. is pursuing NPA pilots and regulatory frameworks.<br>• Financial assistance (e.g., incentives) is a proven mechanism to encourage energy efficiency adoption (also applied to NPAs) but utilities noted that customer engagement (e.g., community outreach, education, and multi-modal engagement) was even more important. |

| | Ontario (initial framework)[80] | New York | California | Massachusetts (draft framework)[81] | Common (among jurisdictions) |
|---|---|---|---|---|---|
| | | | | tangible movement in is geothermal networks. Eversource and National Grid both undertaking pilots; Eversource's pilot is up and running. | |

# APPENDIX C: SUMMARY OF IRP WORKING GROUP FEEDBACK

OEB staff leveraged several IRP Working Group meetings to discuss IRP Framework review topics with IRP Working Group members. The topics and a summary of some of the notable feedback received have been documented in the table below with links to the respective meeting notes and/or other relevant reference materials for more details.

The IRP Working Group's perspectives were considered and contributed to the evolution of OEB staff proposals on various topics; however, the proposals in this discussion paper are those of OEB staff, not the IRP Working Group.

**Table 11. IRP Working Group Discussions on IRP Framework Review**

| Meeting Date | Topic | Key IRP Working Group Feedback/ Takeaways | References |
|---|---|---|---|
| April 9, 2025 | General overview of IRP framework review including consultation scope | • Framework review announcement acknowledges that the Framework has not been successful; everything should potentially be on the table for review, while staying mindful of learnings to date.<br>• Persisting challenges with DCF+ economic evaluation enhancement discussions suggest the need to adjudicate certain elements. Some proposed the idea of revisiting the use of the DCF+ test altogether. | Review announcement<br><br>Meeting #51 Notes |
| April 23, 2025 | Initial analysis of key issues/ themes relevant for the Framework review<br><br>Lessons learned | • Framework has not delivered expected results; OEB should be open to large scale changes if necessary; Working Group members (including Enbridge Gas) prefer a broader scope since limiting the review could hinder its effectiveness.<br>• OEB's IRP approach should not be entirely driven by the government's view of the future but should include the OEB's own analysis of various energy futures while incorporating lessons learned to date.<br>**Key learnings/ observations:**<br>• Regulatory certainty is a key issue to be considered in the evolution of the Framework.<br>• Not considering stranded asset risk in DCF+ economic evaluation undermines a key IRP benefit.<br>• AMP is highly sensitive to demand forecast changes to reinforce IRP's value in avoiding unnecessary capital projects; benefit not currently captured in economic evaluation. | Meeting #52 Notes |

| Meeting Date | Topic | Key IRP Working Group Feedback/ Takeaways | References |
|---|---|---|---|
| May 21, 2025 | Purpose and Form of the Framework<br><br>IRP Assessment Process | **Definition of IRP**<br><br>• Currently references Enbridge Gas's interests as well as customers; the reference to being in Enbridge Gas's best interests has a different meaning and implication than simply recognizing need for a financially viable utility.<br><br>**Purpose and Drivers of the Framework**<br><br>• Important to distinguish between drivers of the original IRP framework explicitly set out by the OEB and those raised by parties and considered throughout the hearing process.<br><br>**Policy and Regulatory Context**<br><br>• Refer to DNV's jurisdictional scan report on best practices for IRP success (e.g., clear drivers, strategic outcomes, regulatory direction, and cost recovery mechanisms); current challenges include uncertainty in climate policy (e.g., removal of Federal Carbon Charge) and lack of specific gas IRP direction; clarify OEB's jurisdiction as an economic regulator in relation to IRP; OEB should remain evidence driven, not solely policy driven.<br><br>**Adaptability and Oversight** – Some notable suggestions:<br><br>• Less prescriptive language (to allow for innovation and focus on principles and goals)<br><br>• Implement periodic reviews with a structured update process; consider models like Illinois' policy manual (4-year cycle with stakeholder input); create a more focused annual IRP review process (like DSM or gas supply plan review) with specific measurable goals and milestones.<br><br>• Inclusivity and transparency (some concerns about limited stakeholder representation in working groups with pressure to accept consensus outcome without broader input)<br><br>• Need for greater regulatory accountability (i.e., without real consequences for Enbridge Gas's failure to implement IRP, Framework improvements will have limited impact).<br><br>• IRP should have its own adjudicated planning process (similar to DSM) with regular updates and integration with AMP; AMP should be formally reviewed and approved by the OEB with capital spending undergoing rigorous annual oversight.<br><br>**IRP Assessment Process:**<br><br>• Project screening issues as many projects are deemed unsuitable for IRP due to institutional bias; Enbridge Gas is structurally incentivized to grow its rate base (due to investor pressure) which conflicts with adoption of non-pipe IRP solutions; holding Enbridge Gas accountable for | Meeting #54 Notes<br><br>Written Comments from IRP Working Group member Jay Shepherd |

| Meeting Date | Topic | Key IRP Working Group Feedback/ Takeaways | References |
|---|---|---|---|
| | | stranded asset risk could shift this tendency (e.g., shifting stranded asset risk from ratepayers to shareholders to make IRP a natural business decision for Enbridge to encourage short term flexible solutions over long term infrastructure)<br>• Consider reversing the onus (make IRP the default and require facilities to justify cost-effectiveness and long-term utilization vs. assuming facilities to be the default, while IRP Alternatives must pass multiple exclusion screenings).<br>• Root issue is structural, not just procedural (changing screening criteria alone won't fix it).<br>• Should emphasize long term interests, clarifying that rate base growth alone is not inherently beneficial.<br>• Other suggestions include use of independent third party for IRP assessment; reassessing the 3-year exemption threshold; taking a broader planning approach by shifting from project-to-project analysis to regional, long-term strategy for peak demand reduction. | |
| June 4, 2025 | Innovation-Related IRP Proposals | **<u>Defining innovation</u>**<br>• Recommend use of broader definition to include new technologies, delivery models, marketing and engagement strategies (even if not cost-effective) to avoid limiting innovation.<br>**<u>Assessing innovation proposals</u>**<br>• Recommend using private sector models as to how innovation proposals should be assessed as utilities lack experience.<br>• An innovative aspect of delivery could include 3rd party organizations already active in related areas (e.g., issue a call for proposals to gauge industry interest and capacity, balancing speed and cost, or holding a competition for 3rd party innovators where Enbridge is required to cooperate not lead).<br>**<u>Oversight and approval process</u>**<br>• Proposal of a multi-year IRP Implementation Plan with annual updates (modeled after DSM but tailored to IRP); emphasis on avoiding siloes by integrating IRP with AMP and facilities planning.<br>• Suggestion to decouple innovation from system needs with a dedicated innovation budget and selection process.<br>• For innovative proposals, members generally recommended nimble processes and ongoing working group support rather than full hearings. | Meeting #55 Notes |

| Meeting Date | Topic | Key IRP Working Group Feedback/ Takeaways | References |
|---|---|---|---|
| N/A (IRP Working Group report written member comments, released July 4, 2025) | Top priorities for the OEB in its review of the IRP Framework | Some priorities identified by IRP Working Group members for the IRP framework review:<br>• Significant overhaul required considering the level of effort to date with no IRP Alternatives being implemented and <2% of investments passing IRP screening<br>• Clarify whether purpose of IRP includes addressing issues such as avoiding stranded assets and meeting climate goals<br>• Review framework's stated goals to ensure alignment with climate and energy transition priorities<br>• Remove barriers to enable IRP Alternatives to be viable alternatives to traditional infrastructure<br>  ○ Address incentive misalignment<br>  ○ Address structural bias towards supply-side investments<br>• Learn from jurisdictional best practices and consider conducting a study to properly assess net job impacts of IRP Alternatives vs. traditional infrastructure<br>• Shift focus from process to outcomes<br>• Improve transparency and data sharing<br>• Resolve and refine the DCF+ test (current evaluation methodology is contentious and underutilized)<br>  ○ Standardized and consistent method to value greenhouse gas emission benefits in assessments of IRP Alternatives<br>  ○ Requirement to consider stranded asset risk when proposing new gas infrastructure<br>• Revisit screening processes and criteria (e.g., improve early-stage filters to ensure more IRP projects reach economic evaluation)<br>• Enable electrification and integrated planning across utilities<br>• Accelerate pilot project processes given the slow progress on the Southern Lake Huron pilot<br>• Improve post-construction evaluation of traditional projects (e.g., actual costs and demand growth after projects are built) to inform future decision and strengthen the case for IRP Alternatives<br>• Ensure accountability in project justification<br>• Re-evaluate the role and authority of the IRP Working Group (e.g., strengthen role and functioning of the IRP | IRP WG 2024 Annual Report |

| Meeting Date | Topic | Key IRP Working Group Feedback/ Takeaways | References |
|---|---|---|---|
| | | Working Group; ensure Working Group is empowered to co-develop initiatives instead of reacting to Enbridge Gas's proposals; requirement for Enbridge Gas to act on Working Group suggestions or provide clear justifications for not doing so) | |
| July 30, 2025 | Electrification | • General support to include electrification as an IRP option; however, there was mention of IEP's view that gas infrastructure remains necessary.<br>• Observation that without electrification, demand reduction IRP Alternatives alone may not prevent many facilities projects.<br>**Governance and responsibility**<br>• Some view a conflict of interest if Enbridge Gas leads electrification; some propose for IESO or electricity distributors to manage electrification and to only defer to Enbridge if electric options are unable to meet system needs.<br>• Collaborating with large electric utilities like Hydro One and Alectra, or IESO is preferred.<br>• Besides electric grid capacity, cost analysis is critical but some major gas costs (e.g., carbon and stranded asset risk) are often excluded making gas appear cheaper. | Meeting #57 Notes |
| September 3, 2025 | 3-year IRP Implementation Plan<br>Future Role of IRP Working Group | **IRP Implementation Plan**<br>• Generally supportive of a 3-year IRP Implementation Plan with annual updates to streamline oversight and reduce repetitive consideration in proceedings.<br>• Support for adjudicative oversight to ensure Enbridge acts on IRP, citing such success with system pruning pilot.<br>• Concerns about balancing nimbleness with ratepayer accountability; front end oversight is needed, not just after-the-fact reviews.<br>**Evolution of Working Group**<br>• Lacks leverage under the current framework; supports a more formal role tied to adjudicated processes; alternatively, empower the working group to approve or amend Enbridge's IRP proposals if no adjudicative process is adopted.<br>• Members recognize some recent improvements in working group operations and materials but emphasized that clear policy direction is still missing and critical for progress to be made on IRP. | Meeting #58 Notes |