**Compendium for Enbridge Gas cross-examination of Guidehouse**

**March 4, 2021**

1. Guidehouse Report, pages 1-5
2. Guidehouse Report, pages 49-50
3. Guidehouse response to BOMA Interrogatory #13
4. Guidehouse response to Enbridge Gas Interrogatory #6.1
5. Guidehouse Report, pages 9 and 53
6. Guidehouse response to Enbridge Gas Interrogatory #4
7. Guidehouse Report, page 29
8. *OEB Act*, section 2

# Executive Summary

## Introduction and Approach

The Ontario Energy Board staff (the OEB staff) contracted Guidehouse Canada Ltd. (Guidehouse) to provide expert support to contribute to the OEB's review of integrated resource planning (IRP) for Enbridge Gas in the regulatory proceeding EB-2020-0091. Guidehouse prepared this report to provide a summary of key IRP activities in New York State, a side-by-side comparison with each of the IRP issues in the Issues List for the EB-2020-0091 proceeding (Issues List) and Enbridge Gas's IRP original proposal in that proceeding (Enbridge Gas IRP Proposal), as well as Enbridge Gas's Additional Evidence filed with the OEB on October 15, 2020. Enbridge Gas provided recommendations for natural gas IRP in Ontario in this evidence.

The analysis in our report focuses on the IRP experience of natural gas utilities in New York State, in particular, Consolidated Edison Inc. (Consolidated Edison Company of New York Inc. (CECONY); Orange and Rockland Utilities, Inc.; jointly referred to hereafter as "Con Edison") and National Grid (National Grid US, including KeySpan Energy Delivery New York (KEDNY), KeySpan Energy Delivery Long Island (KEDLI), and Niagara Mohawk operating areas; referred to hereafter as "National Grid"). The analysis focuses on the CECONY and KEDNY/KEDLI operating areas, which have the most experience with these topics, but also includes details on current and future IRP activities by other New York State natural gas utilities.

Guidehouse prepared this report based on a document review of public reports and regulatory filings, as well as interviews with key staff at Con Edison and National Grid. The New York State Public Service Commission (PSC) has an ongoing proceeding to investigate and improve natural gas planning procedures in New York State, and may result in changes to the IRP processes in New York State. New York Department of Public Service (DPS) staff are expected to publish a whitepaper that outlines a proposal to modernize the gas system planning before November 16th, 2020.[1]

## Industry Best Practices for Natural Gas IRP

Section 1.0 and Section 2.0 of this report provide an introduction and Ontario overview, respectively. Section 3.0 and Section 4.0 provide background on IRP drivers for New York State as well as detailed descriptions for Con Edison's Smart Solutions Program and similar programs in New York State. This list below summarizes the key characteristics and best practices from the natural gas IRP programs we analyzed, as well as lessons learned, and planned improvements identified by Con Edison and National Grid program managers regarding their own IRP experiences. The best practices and key characteristics identified include:

- Developing Benefit Cost Analysis (BCA) procedures that evaluate infrastructure, supply-side, and demand-side solutions with a similar set of assumptions and recognize the risks associated with traditional vs. emerging options can allow for a more transparent IRP process.

[1] This date has been delayed several times and may be further delayed. On November 10th, New York DPS staff filed an additional extension request to file the report on December 14th, 2020. The OEB should check the NYS Gas Planning Proceeding around this date for further updates. http://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterCaseNo=20-g-0131&submit=Search

- Utility program managers implementing demand-side IRP solutions require flexibility to adjust recruitment strategies, incentive amounts, budgets, operating procedures, and other parameters to achieve the goals of the programs.
- Non-traditional supply-side and demand-side solutions carry greater uncertainty compared to traditional infrastructure projects, and utility program managers have overcome these risks by oversubscribing customers and diversifying the IRP solutions. Traditional demand-side solutions such as energy efficiency or heating electrification have a higher degree of certainty of load reduction for each participant whereas demand response (DR) carries greater uncertainty of demand reduction on peak days because it is dependent on customer behavior on those days. To address these issues, utilities deploy a broad mix of solutions, but are cognizant of and adjust for these different levels of certainty. The initial pilot programs being deployed now will provide greater insight into more standardized assumptions for reliability.
- Deploying a diversity of IRP solutions is important to reduce risks in achieving the project goals. Smaller IRP projects may be able to achieve goals in a shorter timeline by expanding existing energy efficiency (EE) or DR programs, whereas larger IRP projects may be best suited for market solicitations and new program developments that have longer timelines.
- Evaluation, Measurement and Verification (EM&V) of IRP initiatives is critical both to confirm demand reduction as well as to ensure customer compliance with program goals and requirements. For example, Con Edison performed EM&V within their Demand Response program to measure the 24-hour gas demand reduction on a peak day and verify that customers did not offset gas consumption with fuel oil, which contradicts the program's environmental goals. Through the Gas DR pilot programs, Con Edison found performing EM&V for demand-side IRP solutions is more challenging without gas Advanced Metering Infrastructure (AMI) deployed across the service territory. There are opportunities to perform EM&V without AMI, but these carry higher costs per unit of peak day reduction (see Section 4.1.3). As experience is gained and lessons are learned from EM&V, firmer conclusions and guidance can be developed about performance, cost effectiveness, and robustness of results.
- New York State utilities have found the operational processes, program design, benefit-cost analyses, and other parameters for the Gas IRP solutions can be similar to existing gas energy efficiency programs or electric Non-Wires Alternative (NWA) programs. The NWA pilots have suggested significant investment in organizational resources (e.g., dedicated time for cross-functional managers and experts, IT system development, internal training updates) is needed upfront to develop the necessary internal processes and operationalize the programs, but that can be useful across both gas and electric IRP solutions. Nevertheless, they have found key differences relating to limitations around space heating end-uses, building codes, customers switching to fuel oil, and other issues that require separate sets of guidelines. The level of investment necessary to operationalize IRP programs will vary based on the capacity, expertise, and experience of utility staff and their current programs, as well as experiences of neighboring utilities that share similar regulatory processes.
- IRP programs take significant time to develop, recruit, launch, and scale and may not align with the timelines of gas planning or engineering departments when looking at traditional infrastructure projects. Of note is that different IRP solutions have different lead times; for example, a DR program may have a shorter lead time than an electrification program. By taking these differences into account, utilities can use a mix of

these IRP programs to reduce load before committing to more expensive infrastructure projects.

- Gas utilities recognize that core planning processes including gas supply and transportation planning, infrastructure maintenance and expansion planning, energy efficiency / demand-side management planning, and IRP planning are interconnected and interdependent. For this reason, gas utilities are seeking to identify how to integrate these processes and sequence the activities to ensure that each planning process properly captures the output of adjacent processes. Having regular discussion with regulator and stakeholder groups around the needs for capacity additions, IRP solutions, and program design plans can reduce uncertainty and facilitate success.
- Regulators need to design the proper incentives for utilities to pursue IRP solutions, including cost-recovery and sharing risk amongst stakeholders similar to a traditional infrastructure investment. Earnings Adjustment Mechanisms (EAMs) have been successful in New York State in aligning the goals of the utilities, regulators, and key stakeholders, although their long-term effectiveness is still uncertain.

## Key Findings from Comparative Analysis of Issues List

Section 5.0 provides a detailed side-by-side comparison of Enbridge Gas's IRP proposal and New York State utility experiences with each of the ten IRP issues in the Issues List for the EB-2020-0091 proceeding. This following list summarizes the key findings from the analysis:

- New York State gas utilities and the PSC have developed a range of gas IRP solutions to address pipeline expansion limitations, peak demand reduction needs, the need to avoid moratoria on new customers, and other goals. The utilities developed the regulatory framework and operational practices to execute the programs in a short period of time. These programs were developed in reaction to urgent issues affecting system reliability, particularly related to delayed and cancelled pipeline capacity projects and/or due to political and environmental pressures. The New York PSC and gas utilities are currently working towards a modernized gas planning framework that will consider supply-side, demand-side, and distribution solutions to meet customer demand while meeting statewide decarbonization goals. More details will be available in the DPS whitepaper expected by November 16th, 2020 as well as other filings over the coming months.[2]
- Enbridge Gas and the OEB have taken a proactive approach to develop a Gas IRP framework. Enbridge Gas's proposed goal is to develop a framework to guide Enbridge Gas's assessment of IRP alternatives (IRPAs) relative to other facility and non-facility alternatives to serve the forecasted needs of Enbridge Gas customers. Ontario already has a framework for the deployment of natural gas Demand Side Management (DSM) programs. Enbridge Gas's IRP Proposal includes a definition of eligible IRPAs, screening and selection criteria for IRPA vs. traditional facility projects, monitoring and reporting guidelines and other elements that attempt to solidify the IRP Framework as a standalone construct that is distinct from the DSM and facility project frameworks.
- Enbridge Gas proposes using a traditional Discounted Cash Flow (DCF) analysis to value IRPA in order to compare these on an equal footing with traditional infrastructure. This approach is defined in the OEB's guidance from proceeding E.B.O. 134, and the

[2] On November 10th, New York DPS staff filed an additional extension request to file the report on December 14th, 2020.

environment for cost benefit analysis has evolved significantly since this methodology was originally developed. Con Edison has developed a formal BCA handbook, which includes a detailed methodology for calculating all the benefits and costs of particular IRPAs as well as examples of different types of IRPAs, such as: demand response, renewable natural gas (RNG). The BCA captures all the costs and benefits and can facilitate a transparent discussion with stakeholders.

- Enbridge Gas has indicated that deploying an AMI system will help enable the IRP framework, as these meters can allow Enbridge Gas to collect hourly peak demand data and target the most effective deployment of IRPA.[3] Con Edison is in the process of deploying AMI infrastructure across its service territory and has deployed IRP solutions in areas with and without AMI installed. Con Edison has indicated that performing demand-side IRP programs without such infrastructure is feasible but carries additional challenges and costs.
- The experiences to date in New York State with gas IRP solutions through Con Edison Smart Solutions and National Grid Non-Pipeline Solution (NPS) programs, as well as pilots with other gas utilities, provide insight into the opportunities and challenges when relying on non-traditional solutions to defer pipeline investments. Furthermore, these gas IRP solutions leveraged the program designs and operating procedures from existing energy efficiency and electric NWA programs.

Section 6.0 outlines several key differences between the Enbridge Gas service territory and those of New York State gas utilities that may be relevant to IRP implementation and that should be taken into consideration in a comparative analysis.

## Recommendations

The following list summarizes Guidehouse's key recommendations for the OEB to consider when reviewing Enbridge Gas's IRP proposal and evaluating opportunities to implement natural gas IRP in Ontario:

1. The OEB should encourage the development of a comprehensive Benefit Cost Analysis (BCA) Handbook for Gas IRP, or supplemental guide to the approach outlined in E.B.O. 134 , that evaluates infrastructure, supply-side, and demand-side solutions with a similar set of assumptions for costs and benefits. Stakeholders can provide comment on the proposed BCA Handbook / supplemental guide and build an understanding of the costs, benefits, and risks for different IRP options, and allow for a more transparent IRP process.
2. The OEB should work to more closely align and sequence the planning activities for gas supply, demand, infrastructure, energy efficiency (EE)/demand-side management (DSM), IRP, Utility System Plans (USPs) and other relevant matters, wherever possible. Developing an IRP framework that describes the importance of different planning activities and how the individual activities inform the IRP planning process will allow for more consistent outcomes. For example, filings and related proceedings around gas supply, transportation planning, infrastructure maintenance, and EE/DSM will have

[3] Guidehouse notes that there are concerns in Ontario regarding the cost and efficacy of AMI due to prior experience with electric smart meters.

relevance for identifying IRP needs and opportunities, and applying a logical sequencing can lead to a more consistent, up-to-date view of these matters for IRP planning.

3. Similar to above, the OEB should develop the gas IRP framework to be consistent with the regulatory framework for natural gas infrastructure approvals. This includes consistency with the OEB's Framework for the Assessment of Distributor Gas Supply Plans, USP filing requirements that are required for cost of service rate applications, and filing requirements and guidelines for approval of hydrocarbon pipelines and facilities, among other regulatory requirements.

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

5. The OEB should work to establish a common understanding amongst stakeholders for the gas IRP process and how benefits, costs, risks, and other parameters will be shared by shareholders, ratepayers, and other parties.

6. The OEB should develop the gas IRP framework to provide utilities with sufficient flexibility to quickly adjust program designs, budgets, implementation plans, and other processes to adapt the IRP programs to each situation. Furthermore, incentives such as Earnings Adjustment Mechanisms (EAMs) should be considered to incentivize innovative approaches that may lead to more targeted outcomes or greater demand reductions. The long-term effectiveness of EAMs remains to be seen due to the limited track record of these incentives.

7. Should the OEB and the Independent Electricity System Operator (IESO) consider developing a specific electric Non-Wires Alternative (NWA) framework in the future, the OEB should consider aligning Gas IRP and Electricity IRP frameworks to share the cost and resource investments to develop operational processes, program design, benefit-cost analyses, and other aspects of either IRP proceeding.[4] Within New York State, leveraging the experience of electric NWA when developing the gas Non-Pipeline Solution (NPS) programs allowed for easier understanding and launch by utility, regulatory, customers, and other stakeholders. Improved coordination across electric and gas utilities will allow for more transparent analysis of the benefits and costs to achieve future provincial policy objectives.

[4] There are multiple other frameworks in Ontario that are similar to a NWA framework. These include the Regional Planning Process and Integrated Regional Resource Plans as well as the Conservation and Demand Management Frameworks, which have guidelines on how conservation should be incorporated in planning. The integration of these frameworks with the Gas IRP process could also be considered.

NY PSC ultimately rejected the 5th solution of traditional pipeline expansion, leaving questions on how Con Edison would address this situation.[108] Con Edison and National Grid have enacted moratoria on new customer connections in response to localized constraints (Con Edison in Westchester County, National Grid on Long Island). Should the proposed programs not meet their objectives, the utilities would likely pursue additional NPS strategies (e.g., greater customer electrification) and moratoria.

Our interview with National Grid highlighted the risk of making traditional infrastructure investments that may not be fully utilized in the future due to IRP solutions, as well as the risk of not making those infrastructure investments today and expecting IRP solutions to materialize in future years. Within the Joint LDC's letter within the Future Gas Planning proceeding, the group identifies two types of reliability when evaluating IRP resources:[109]

- "Deliverability Reliability relates to unplanned delivery interruptions and refers to the on-demand reliability of a resource (i.e., risk concerning whether the resource will be available and able to produce when called upon, especially during extreme cold conditions).
- Recontracting/Renewal Reliability refers to whether a particular contracted resource, or close substitute from another supplier, can be extended after the current contract term expires or whether, in the alternative, issues such as re-permitting challenges, regulatory changes, financial viability, and market conditions preclude the resource or close substitute from being included in the resource portfolio beyond the contract term."

As described in Section 4.1, peaking services or CNG trucking has higher deliverability reliability for the contracted period, but lower renewal reliability because the contracts may not be able to be called upon in future years. IRP solutions such as heating electrification that completely remove a customer's gas heating system from service would likely have higher reliability in both categories. Conversely, gas DR programs may have lower reliability in both categories since customers may underperform during peak events and would need to enroll each year.

To address these risks, the Joint LDCs proposed a framework to apply derating factors for supply-side and demand-side IRP solutions when determining the final capacity forecasts. The proposal provides some indicators for these derating factors, whereas others will need further refinement based on the current pilots:[110]

- **Supply-Side Resources:**
    - Interstate pipeline contract resources (firm transportation and storage with rollover): 100% (i.e., no derating), unless there are specific concerns for the resource, then 0-15% derating for deliverability and renewal reliability

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[108] New York Public Service Commission. "Order Approving in Part, with Modification, and Denying in Part Smart Solutions Program." Case." Case 17-G-0606. July 12, 2018. http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={4AA81E30-D21E-4F34-BA06-9E909EB1143C}

[109] New York Joint LDCs. "Modernized Gas Planning Process: Standards for Reliance on Peaking Services and Moratorium Management." Case 20-G-0131. July 17, 2020. http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={A66EE1E3-A429-4A0F-9D64-C5D0101BCF42}

[110] New York Joint LDCs. "Modernized Gas Planning Process: Standards for Reliance on Peaking Services and Moratorium Management." Case 20-G-0131. July 17, 2020. http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={A66EE1E3-A429-4A0F-9D64-C5D0101BCF42}

  - On-system CNG and LNG storage: 0-25% derating for deliverability and renewal reliability
  - Delivered services (firm contracts for peaking capacity): 0-15% for deliverability reliability, 0-35% for renewal reliability
  - On-system CNG and LNG trucking supplies: 0-50% derating for deliverability and renewal reliability
- **Demand-Side Resources:**
  - Include energy efficiency, demand response, NPAs, and heating electrification (i.e., conversion of end-uses to electricity): to be determined based on further evaluation of pilots underway

How these risks are to be allocated to shareholders and ratepayers is still undetermined in New York State. The DPS whitepaper expected in October 2020 may provide greater guidance.

### 5.1.9 What incentives are appropriate to ensure effective IRP outcomes?

**Enbridge Gas Proposal**:

Enbridge Gas indicates in its Additional Evidence that incentivization of IRPA may not be needed to achieve the objective of providing an equal footing for both traditional capital investments and IRPAs. The proposal suggests that allowing Enbridge Gas to add IRPA and associated costs to rate base will achieve this goal without the need for further incentivization.

Enbridge Gas indicates that if the OEB wishes to incentivize IRPA, then the topic should be addressed in a separate study, e.g. through an upcoming annual rate setting proceeding.

**New York State Programs**:

In the original Smart Solutions filing Con Edison requested cost recovery for the various elements of the Program, including customer incentives for the non-pipeline solutions; and requested budget flexibility to operate the program. The cost recovery and program flexibility were approved by the PSC.[111]

Furthermore, the PSC has allowed Earnings Adjustment Mechanisms (EAMs) in Con Edison’s electricity and natural gas energy efficiency programs. EAMs are a series of metrics that encouraged Con Edison to achieve certain energy efficiency, demand reduction, and electrification targets above required goals.[112] The PSC determines the number of EAMs the utility has achieved and adjusts the earnings that Con Edison is allowed, through its rate case. The PSC has not awarded EAMs for gas energy efficiency solutions under the Smart Solutions Program to avoid providing a “double incentive” in addition to previously agreed-upon EAMs that are tied to gas energy efficiency.

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[111] Con Edison. Petition Of Consolidated Edison Company Of New York, Inc. For Approval Of The Smart Solutions For Natural Gas Customers Program. Case 17-G-0606. September 29, 2017. http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={EBDD5DAE-ED57-4D90-BFF7-B407517BE133}

[112] Con Edison. “Order Adopting Terms Of Joint Proposal And Establishing Electric And Gas Rate Plan.” Case 19-G-0066. January 16, 2020. https://conedison.gcs-web.com/static-files/2163c1fa-d830-404d-9fa6-10f19beaf9f5

(a) By definition, how could IRP pilots and programs been developed without an integrated resource plan?

**Guidehouse Response:**

On Page 13 of the Guidehouse report, we describe the experiences of Con Edison and National Grid to develop IRP-type pilots and programs. "In each case, the utilities initiated the development of the Gas IRP pilots and programs on an ad hoc basis in response to an urgent need to alleviate peak day capacity constraints, both today and in the near future." Section 3 of the report describes the set of solutions, including moratoria on new customers, that the utilities have used to accommodate a rapid increase in demand while experiencing delays and cancellations of pipeline expansions.

These pilots and programs were similar to the types of solutions described in Enbridge's IRP proposal, although the term "IRP" was not used by the New York State utilities. On page 7 of the Guidehouse report, we note "This report uses multiple terms for IRPA, which have been left in for alignment with source documents from other jurisdictions. The terms non-pipeline solutions (NPS), non-pipeline alternatives (NPA), and IRP solution are all used interchangeably with IRPA."

## *1.13 1-BOMA-13*

**Reference: Guidehouse, 2020, Pages 15/16, Table 1 and Table 2**

**Preamble:**

Table 1 and 2 from Guidehouse report

**Question(s):**

(a) Please provide a combined table with 3 columns, including in the third column, the current use of benefit/costs categories required by the OEB's current requirements of Enbridge.

**Guidehouse Response:**

The OEB's current requirements for benefit-cost analysis (BCA) for Enbridge Gas differ for transmission and distribution system expansion projects and DSM programs. The table below summarizes the key BCA tests and guidance documents for each.

| Benefit-Cost Test | Use | Guidance Document |
|---|---|---|
| Total Resource Cost + | DSM programs | Filing Guidelines to the Demand Side Management Framework for Natural Gas Distributors (2015-2020)[9] |

[9] https://www.oeb.ca/oeb/_Documents/EB-2014-0134/Filing_Guidelines_to_the_DSM_Framework_20141222.pdf

| **Benefit-Cost Test** | **Use** | **Guidance Document** |
|---|---|---|
| E.B.O. 134 (three-stage analysis) | Transmission system expansion | Filing Guidelines on the Economic Tests for Transmission Pipeline Applications[10] |
| E.B.O. 188 | Distribution system expansion | Guidelines for Assessing and Reporting on Natural Gas System Expansion in Ontario[11] |

Within Section 4.1 of the Guidehouse report, we summarized the original and revised Con Edison BCA Handbook for Non-Pipeline Solutions. The 2020 BCA updates are generally consistent with the original list of benefits and cost categories and reflect further specificity of the NPS opportunities and proposed framework (e.g., addition of shareholder incentives / earnings adjustment mechanisms [EAMs]). As such, we will respond to the question with a focus on the revised version from September 2020. Con Edison proposes to use a Societal Cost Test as its primary test, with UCT and RIM tests as secondary tests. As noted in section 3.1 and Table 3.1 of the BCA Handbook, all listed costs and benefits shown in the table below with the exception of lost utility revenue and shareholder incentives would be considered in the Societal Cost Test.  These two categories are not included in the Societal Cost Test as they are considered transfers between stakeholder groups that have no net impact on society as a whole. The UCT and RIM tests would be conducted, but would serve in a subsidiary role to the SCT test and would be performed only for the purpose of arriving at a preliminary assessment of the impact on utility costs and ratepayer bills of measures that pass the SCT analysis. See Green Energy Coalition-6 for further details.

The tables below provide a side-by-side comparison of the benefits and costs within the revised Con Edison BCA Handbook for Non-Pipeline Solutions and the OEB guidance documents for natural gas DSM programs (TRC+), transmission expansion projects (E.B.O. 134), and distribution expansion projects (E.B.O. 188).

**Comparison of Benefit Categories between**
**Con Edison BCA Handbook and OEB BCA Guidance Documents**

| Benefit Categories from Con Edison Revised BCA Handbook | Considered in EBO 134 Stage 1 / EBO 188?[12] | Considered in DSM Framework (TRC+ test)? |
|---|---|---|
| Avoided Peaking Services | Yes | Yes, Avoided Supply Costs (capital, operating and commodity costs) |
| Avoided Pipeline and Storage Capacity Costs | Yes | Yes, Avoided Supply Costs (capital, operating and commodity costs) |

[10] https://www.oeb.ca/oeb/_Documents/Regulatory/Filing_Guidelines_Tx_Pipelines_Applications.pdf

[11] https://www.oeb.ca/sites/default/files/uploads/documents/regulatorycodes/2019-01/EBO-188-AppB-Guidelines-Gas-Expansion-19980130.pdf

[12] This column was based on the guidance for E.B.O. 188. Guidance for stage 1 of E.B.O. 134 is less detailed, but appears to be essentially identical in terms of the costs and benefits that should be included.

| Benefit Categories from Con Edison Revised BCA Handbook | Considered in EBO 134 Stage 1 / EBO 188?[12] | Considered in DSM Framework (TRC+ test)? |
|---|---|---|
| Avoided Commodity Costs | No | Yes, Avoided Supply Costs (capital, operating and commodity costs) |
| Avoided On-System Capacity Expense | Yes | Yes, Avoided Supply Costs (capital, operating and commodity costs) |
| Reliability / Resiliency | Not specifically defined | Not specifically defined |
| External Benefits (e.g., Avoided CO2 and Other Emissions, Land and Water Impacts) | Not in stage 1, potentially in stages 2 or 3 | • Avoided CO2 emissions are monetized as Avoided Supply Costs<br>• Non-Energy Benefit Adder may also consider environmental, societal, utility and other participant benefits |

**Comparison of Cost Categories between Con Edison BCA Handbook and OEB BCA Guidance Documents**

| Cost Categories from Con Edison Revised BCA Handbook | Considered in EBO 134 Stage 1 / EBO 188?[13] | Considered in DSM Framework (TRC+ test)? |
|---|---|---|
| Program Administration | Yes | • Yes, Program costs (Development, promotion, delivery, EM&V, administration).<br>• Incentives to participants are not included in program costs |
| Incremental On-System Capacity Expenses | Yes | Yes, Avoided Supply Costs (capital, operating and commodity costs) |
| Lost Utility Revenue | Yes | Not as part of TRC+ test, however, Framework includes Lost Revenue |
| Shareholder Incentives | Not applicable | Not as part of TRC+ test, however, Framework includes Shareholder Incentive |
| Incremental Participant NPS Cost | Not in stage 1, potentially in stages 2 or 3 | Yes, Net Equipment Costs (Installation, O&M, fuel cost) |
| Alternative Fuel Cost (e.g., Electricity) | Not in stage 1 (assuming that utility is not provider of the alternative fuel), potentially in stages 2 or 3 | Yes, Net Equipment Costs (Installation, O&M, fuel cost) |
| External Costs (e.g., Alternative Fuel CO2 and Other Emissions, Land and Water Impacts) | Not in stage 1, potentially in stages 2 or 3 | Indirectly through Non-Energy Benefit Adder (which assumes net external impacts are benefits) |

[13] This column was based on the guidance for E.B.O. 188. Guidance for stage 1 of E.B.O. 134 is less detailed, but appears to be essentially identical in terms of the costs and benefits that should be included.

Guidehouse notes several caveats regarding the interpretation of the EBO 134/EBO 188 economic tests. These tests are intended to assist the OEB in making determinations regarding potential transmission/distribution system expansion, by outputting a Net Present Value (NPV). They were not designed to compare alternative options to meet a system need. However, it is possible to repurpose either of these tests as an options analysis, by comparing the NPV produced by the EBO 134/188 tests for different options to meet a system need, and determining which option has the highest NPV (note that all options for meeting a system need may yield a negative NPV).

Guidehouse also notes that OEB guidance regarding stages 2 and 3 of the EBO 134 test is limited. The OEB indicates in its Filing Guidelines on the Economic Tests for Transmission Pipeline Applications that “the second stage should be designed to quantify other public interest factors not considered at stage one. All quantifiable other public interest information as to costs and benefits should be provided at this stage. The third stage should take into account all other relevant public interest factors plus the results from stage one and stage two.”

## *1.14 1-BOMA-14*

**Reference: Guidehouse, 2020, Page 18, Section 4.1.2**

**Question(s):**

(a) The AMI benefits lists are predominantly related to smart metering of electricity. What are the specific benefits to natural gas utilities and customers?

**Guidehouse Response:**

As described in Section 4.1.2, Con Edison is both a natural gas and electric utility, and the AMI Business plan includes implementing AMI across customer electric and gas meters. As such, the benefits and opportunities from AMI meters are described collectively for both electric and gas meters.

It is Guidehouse's opinion that natural gas AMI could provide several of the benefits listed in the AMI Business plan, including but not limited to: reduces customer energy use, increased customer control over energy usage, reduces meter readings, enhances service reliability, cost savings and avoided costs, etc.

## *1.15 1-BOMA-15*

**Reference: Guidehouse, 2020, Pages 52-58, Section 6 (Differences between Enbridge Gas and New York State Service Territories)**

**Question(s):**

(a) This table provides an excellent comparison between the jurisdictions, but it is not clear how these differences would affect IRP. Please elaborate.

**Guidehouse Response:**

Guidehouse has reviewed ICF's Updated Jurisdictional Review included with Enbridge Gas's Additional Evidence and found the analysis generally aligned with our research findings. Guidehouse was not asked to conduct a detailed point-by-point review and comment of the ICF report.

## *3.7 Enbridge Gas 6.1*

**Reference: Recommendations**

**Preamble:**

The evidence states that "The OEB should encourage the development of a comprehensive Benefit Cost Analysis (BCA) Handbook for Gas IRP, or supplemental guide to the approach outlined in E.B.O. 134, that evaluates infrastructure, supply-side, and demand-side solutions with a similar set of assumptions for costs and benefits"

**Question(s):**

Please provide more specific detail regarding Guidehouse's recommendations for the content of a future BCA Handbook for Ontario natural gas IRP should the Board determine that it is appropriate to develop one.

**Guidehouse Response:**

It is the perspective of Guidehouse that, should the OEB determine to develop a BCA Handbook, the content should be developed by the OEB with input from key stakeholders. An OEB consultation may provide the means to accomplish this.

# 4.0 Energy Probe

The section contains the interrogatories submitted by Energy Probe and Guidehouse's responses.

## *4.1 Energy Probe 1*

**Reference: OEB Staff /Guidehouse Report, Page 3**

**Preamble:**

"Enbridge Gas proposes using a traditional Discounted Cash Flow (DCF) analysis to value IRPA in order to compare these on an equal footing with traditional infrastructure. This approach is defined in the OEB's guidance from proceeding E.B.O. 134, and the environment for cost benefit analysis has evolved significantly since this methodology was originally developed."

**Question(s):**

question the future role of natural gas infrastructure to serve building, industrial, transportation, and electric generation end-uses. Preliminary Pathways modeling performed by E3 for the CLCPA Climate Action Council highlights the significant emphasis on end-use electrification to reach statewide goals.[16] Furthermore, the New York City mayor recently announced a plan to prohibit the use of natural gas in all large buildings by 2040 to support city targets.[17]

Downstate natural gas utilities, including Con Edison and National Grid, have seen significant demand growth in recent years driven by both population and economic growth in the service territory, but also by policy efforts to convert fuel oil heating customers to natural gas. The gas utilities have enacted a diverse approach to accommodate rapid increase in demand, including transmission pipeline expansions and traditional infrastructure approaches, as well as non-traditional approaches, such as compressed natural gas (CNG) / liquefied natural gas (LNG) injection, targeted EE/DSM, heating electrification and other strategies. Due to significant delays and challenges with pipeline projects by regulatory agencies, both utilities unilaterally enacted moratoria on new customer connections in specific parts of their service territory. Within the Supply / Demand Analysis in the Gas Planning Proceeding, Con Edison details the permitting challenges that have delayed or restricted the development of infrastructure projects over the last 5-10 years.[18] The New York State Department of Environmental Conservation's denial of multiple water permit applications[19] for the Northeast Supply Enhancement (NESE) project ultimately led the developer to abandon the project.[20] This pipeline cancellation primarily affected National Grid but also impacted Con Edison's long-term supply outlook. Section 4.0 describes these topics in greater detail.

It is Guidehouse's understanding that New York State policymakers have not made an explicit directive or policy announcement to date regarding the future of natural gas consumption within the state or restriction of further natural gas infrastructure. It is Guidehouse's further understanding that major stakeholders including regulatory agencies, gas and electric utilities, and real estate developers all recognize the overall policy direction and trend towards greater electrification of buildings, transportation, and industry. Nevertheless, there has not been a coordinated effort to address questions around future gas infrastructure investment to serve new and existing customers, maintain system safety and reliability, and potentially recover costs for stranded assets in the future. Many anticipate that the CLCPA Climate Action Council as well as the PSC Future Gas Planning Proceeding (Section 3.3) will provide greater insight into these topics when completed.

New York State policymakers and the PSC have a history of promoting utility-supported energy efficiency programs to support the state's environmental goals. In December 2018, the PSC adopted significantly accelerated utility energy efficiency targets under the governor's *New Efficiency: New York* plan, which will double utility energy efficiency achievement over 2019 to

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[16] New York State Climate Action Council, Meetings and Materials https://climate.ny.gov/Meetings-and-Materials

[17] DiChristopher, Tom. "How New York City plans to end natural gas, oil use in buildings." February 25, 2020. S&P Global Market Intelligence https://www.spglobal.com/marketintelligence/en/news-insights/latest-news-headlines/how-new-york-city-plans-to-end-natural-gas-oil-use-in-buildings-57232171#:~:text=Mayor%20Bill%20de%20Blasio%20recently,the%20Boston%20area%20and%20Seattle.

[18] Con Edison. "Proceeding on Motion of the Commission in Regard to Gas Planning Procedures – Supply/Demand Analysis for Vulnerable Locations." Case 20-G-0131. July 17, 2020 http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={FCF94472-7929-4594-8CD0-C3903FDE6927}

[19] Water permits were critical to the NESE project since major portions of the pipeline would have traveled under water between New Jersey and Long Island, New York.

[20] Reuters. "New York denies PA-NY Williams Northeast Supply natgas pipe." May 15, 2020. https://www.reuters.com/article/us-natgas-williams-pipeline/new-york-denies-pa-ny-williams-northeast-supply-natgas-pipe-idUSKBN22R3FT

State gas utility service territories. Guidehouse took these findings under consideration when developing the recommendations in Section 8.0.

**Table 5. Comparison Between New York and Enbridge Gas Service Territories**

| Key Topic | New York State | Enbridge Gas |
|---|---|---|
| Utility Types | Both Con Edison and National Grid are combined natural gas and electric utilities, so IRP solutions such as electrification or policy shifts in New York State to encourage fuel switching from natural gas to electricity do not pose existential threats to the utility itself. Rather, the limitations on future gas infrastructure may create operational and financial uncertainty in one area of the business, whereas other areas of their business may benefit substantially in the long run. Many gas utilities in New York State are dual fuel, although several such as National Fuel Gas Distribution Company and St. Lawrence Gas are single fuel. | Enbridge Gas is currently a natural gas-only utility, although it is seeking confirmation that non-gas alternatives (including alternatives that use electricity, such as heat pumps) can be included in the range of possible and available IRPAs. |
| Gas Supply Issues | Delays and challenges in obtaining regulatory approval for new upstream pipeline capacity have caused near-term risks to utilities' ability to meet customer demand for natural gas, causing both Con Edison and National Grid to impose moratoria on new customer connections in parts of their service territories, driving efforts for IRP solutions. | Ontario does not currently face the same natural gas supply issues present in New York State. |

# 3.0 Enbridge Gas

The section contains the interrogatories submitted by Enbridge Gas and Guidehouse's responses.

## *3.1 Enbridge Gas 4.1*

**Reference: Recommendations**

**Preamble:**

The evidence states that "The OEB should encourage the development of a comprehensive Benefit Cost Analysis (BCA) Handbook for Gas IRP, or supplemental guide to the approach outlined in E.B.O. 134, that evaluates infrastructure, supply-side, and demand-side solutions with a similar set of assumptions for costs and benefits."

**Question(s):**

Please explain any adjustments that might be needed to E.B.O. 134 (all stages) for it to be capable of effectively comparing facility and non-facility alternatives (IRPAs or NPAs).

**Guidehouse Response:**

The tests to be used for comparing gas supply-side alternatives are based on a discounted cash flow analysis (DCF) set in E.B.O. 134. Gas DSM programs are compared based on cost-effectiveness tests, applying the Total Resource Cost Test and the Program Administrator Cost Test. The DCF for supply-side alternatives and the cost-effectiveness tests chosen for DSM were not selected specifically to align with each other.

See Environmental Defense-2. Guidehouse believes it is difficult to draw firm conclusions for Ontario from the initial pilots and proposed frameworks in New York State, particularly when applying the findings across jurisdictions. Therefore, Guidehouse did not provide specific recommendations regarding cost-effectiveness tests for Natural Gas IRP in Ontario. We have indicated that developing a BCA Handbook with the appropriate tests and how to apply them may be of value. Should the OEB determine to develop a BCA Handbook, the content should be developed by the OEB with input from key stakeholders.

## *3.2 Enbridge Gas 5.1*

**Reference: Executive Summary**

**Preamble:**

The evidence states that "New York Department of Public Service (DPS) staff are expected to publish a whitepaper that outlines a proposal to modernize the gas system planning before November 16th, 2020."

**Question(s):**

a) Please provide an update on the status of this paper including when it is expected to be published.

In the NPA Framework filing, Con Edison outlined the types of projects that could likely be considered for IRP solutions and those that could not use IRP solutions[73] as follows:

***Likely Qualified for NPA Consideration***

- **Load Relief**: Heating electrification, demand response, and energy efficiency measures could reduce overall demands in a specific area below the threshold needed to maintain reliability.
- **Regulator Station Upgrade**: Similar to above, heating electrification, demand response, and energy efficiency measures could reduce overall demands in a specific area below the threshold needed to maintain reliability.
- **Main Replacement Program**: If all customers served by the gas supply main voluntarily convert to alternatives, the main replacement project could be avoided. Con Edison notes that voluntary conversion and disconnection of all customers would present significant challenges.

***Likely Not Qualified for NPA Consideration***

- **Non-Distribution Infrastructure**: Investments such as information technology systems and AMI networks cannot be replaced by NPA.
- **Emergent Safety**: Investments needed to address emergent safety risks are required by state and federal law to be performed quickly, and cannot be replaced by NPA.
- **Regulatory Requirement**: Near-term infrastructure upgrades needed to meet regulatory requirements cannot reasonably be replaced by an NPA due to the volume of work that is required to be completed in a short time frame. As the NPA program grows, future projects may be evaluated for possible replacement with an NPA.

Furthermore, Con Edison describes how areas in its service territory that would be more vulnerable to future supply disruptions would be prioritized for NPA consideration. The Smart Solutions program followed this approach by focusing market solicitations on Westchester County and providing different incentive levels for the gas DR programs based on customer location.

Within the NPA Framework document, Con Edison proposed the following process for NPA consideration, highlighted in Figure 2:[74]

- Identifying Natural Gas Distribution System Needs
- Identifying Infrastructure Projects that can be Deferred or Replaced by Non-Traditional Alternatives
- Assessing NPA Suitability Criteria, such as size of relief needed, timeline, cost, geographic location, feasibility, and other factors

[73] Con Edison "Proposal for Use of a Framework to Pursue Non-Pipeline Alternatives to Defer or Eliminate Capital Investment in Certain Traditional Natural Gas Distribution Infrastructure." Case 19-G-0066 September 15, 2020 http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={2CCB0D2A-183A-483B-9F56-87878E0471FA}

[74] Con Edison "Proposal for Use of a Framework to Pursue Non-Pipeline Alternatives to Defer or Eliminate Capital Investment in Certain Traditional Natural Gas Distribution Infrastructure." Case 19-G-0066 September 15, 2020 http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={2CCB0D2A-183A-483B-9F56-87878E0471FA}

## Ontario Energy Board Act, 1998

S.O. 1998, CHAPTER 15
SCHEDULE B

**Board objectives, gas**

**2** The Board, in carrying out its responsibilities under this or any other Act in relation to gas, shall be guided by the following objectives:

1. To facilitate competition in the sale of gas to users.
2. To inform consumers and protect their interests with respect to prices and the reliability and quality of gas service.
3. To facilitate rational expansion of transmission and distribution systems.
4. To facilitate rational development and safe operation of gas storage.
5. To promote energy conservation and energy efficiency in accordance with the policies of the Government of Ontario, including having regard to the consumer's economic circumstances.

5.1 To facilitate the maintenance of a financially viable gas industry for the transmission, distribution and storage of gas.

6. To promote communication within the gas industry. 1998, c. 15, Sched. B, s. 2; 2002, c. 23, s. 4 (2); 2003, c. 3, s. 3; 2004, c. 23, Sched. B, s. 2; 2009, c. 12, Sched. D, s. 2; 2019, c. 6, Sched. 2, s. 2.