CLIENT PROPRIETARY

IRPA DCF+ Review and Analysis

Prepared for:

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Glossary of Terms and Acronyms

BCA: Benefit-Cost Analysis

BCA Order: Case 14-M-0101 – Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision, Order Establishing the Benefit-Cost Analysis Framework (issued January 21, 2016)

CNG: Compressed Natural Gas

DER: Distributed Energy Resources

DSP: Distributed System Platform

DNO: Distribution Network Operator

DSM: Demand Side Management

EE: Energy Efficiency

gas EE PAs: The Massachusetts natural gas energy efficiency Program Administrators

Handbook: Refers to Con Edison's BCA Handbook

LNG: Liquid Natural Gas

NEB(s): Non-Energy Benefit(s)

NPA: Non-pipe Alternative

NPS: Non-pipe Solution

NPS BCA Handbook: Refers to Con Edison's NPS BCA Handbook

NWA: Non-Wire Alternative

Ofgem: Office of Gas and Electricity Markets

PUC: Public Utilities Commission

RCC: Real Carrying Capacity Charge

RI Test: Rhode Island Test

RIM: Ratepayer Impact Measure

RNG: Renewable Natural Gas

SCT: Societal Cost Test

SRP: System Reliability Procurement

T&D: Transmission and Distribution

UCT: Utility Cost Test

UK: The United Kingdom

1. Introduction

Enbridge Gas Inc. engaged Guidehouse to develop recommendations on how the currently approved Discounted Cash Flow (DCF+) test could be improved to better identify and define the costs and benefits of Facility Alternatives and Integrated Resource Planning Alternatives (IRPAs), including infrastructure, supply-side and demand-side IRPAs.

The recommendations include a review of:

- The impacts and considerations of the current regulatory context and the envisioned DCF+ approach, as established in the EB-2020-0091 proceeding, and based upon the procedures of E.B.O. 134 and 188
- Approaches to expand the inputs of the DCF+ to recognize increasing carbon costs and GHG standard
- How the risk that a constraint remains after an IRPA implementation is considered and addressed
- The estimated impact on gas supply costs[1]
- Any additional cost and benefit assumptions as suggested by consultant as critical

As part of this engagement, Guidehouse has been engaged to conduct a review of how other jurisdictions include costs and benefits within economic tests used to screen non-pipeline alternatives as well as a review of other jurisdictions' IRP cost-benefit analyses in the context of natural gas planning.

1.1 Key Findings

Below is a summary table of the tests considered in this report.

Table 1 – Key Economic Feasibility Tests

	E.B.O 134 (1988)	E.B.O 188 Test (1998)	TRC+ Test (2015)	DCF+ Test (2020)
Application	Leave to construct applications for pipeline **transmission** projects	Natural gas **distribution system expansion**	Cost-effectiveness of Demand Side Management ("DSM") programs	Compare IRP Plan(s) to baseline Facility Alternative (Enbridge only)
Phases	**Stage I**: DCF Analysis **Stage II**: Quantifies other public interest factors not considered at stage one **Stage III**: Accounts for all other relevant public interest factors plus the results from stage one and stage two	DCF Analysis (for Rolling Project Portfolio)	Single-phase TRC test	**Phase one**: Economic benefits and costs from the utility perspective **Phase two**: Assesses the incremental economic benefits and costs incurred by customers from the IRP Plan(s) or Facility Alternative(s) **Phase three:** Assesses the incremental societal benefits and costs

[1] https://www.rds.oeb.ca/CMWebDrawer/Record/720232/File/document Decision and Order eb-2020-0091 Enbridge Gas Inc. pp. 56 &57

OEB's key findings presented in EB-2020-0091 are presented In Table 2

Table 2 – EB-2020-0091 - OEB Key Findings

Theme	Findings
Technical Evaluation	1. It is appropriate for Enbridge Gas to undertake a technical evaluation to first determine if the IRPAs considered can meet the need, prior to doing an economic evaluation. 2. Enbridge Gas may use derating factors or oversubscription of IRPAs to address uncertainty regarding forecast savings (factors being relevant to both technical and economic evaluations). 3. Enbridge Gas should include in its request for OEB approval of specific IRP Plans both the level of oversubscription and the supporting rationale.
Economic Evaluation	1. DCF+ test (including its focus on rate impacts, in its phase 1), should be the economic evaluation test used in the IRP Framework. 2. DSM and IRP are distinct from each other. The post-2021 DSM Plan should be to assist customers in making their homes and business more efficient in order to better manage their energy bills[2], while IRP is aimed at reducing peak demand in specific geographic areas to replace infrastructure investment with an IRPA investment. 3. Given Economic Evaluation's finding 2, it is reasonable that a different economic test should be applied in the IRP Framework than in the DSM Framework. 4. An IRP Plan is attempting to reduce the long-term cost to all Enbridge Gas customers, and that it is therefore important to have an evaluation test that looks at impacts from the gas customer perspective – this being consistent with OEB's statutory objectives. 5. OEB encourages Enbridge Gas to make application to the OEB for approval of the IRP Plan, and then implement and monitor the IRP Plan to make adjustments as appropriate. 6. Enbridge Gas should have some discretion in selecting an alternative to meet a system need that does not have the highest score on phase 1 of the DCF+ test, as there may be considerations or factors that are important in phases 2 and 3 or are difficult to quantify. However, Enbridge Gas would need to provide full justification of their proposal if they recommend a higher cost alternative.
Further Work on Economic Evaluation Methodology	1. OEB accepts the categories of benefits and costs proposed by Enbridge Gas for the three phases of the DCF+ test for the use of this test in the IRP Framework. 2. The OEB recognizes that the DCF+ test could be improved to better identify and define the costs and benefits of Facility Alternatives and IRPAs and clarify how these costs and benefits should be considered with the DCF+ test. This could include expanding the inputs to recognize increasing carbon costs, the risk that a constraint remains unresolved, and impact on gas supply costs. 3. The OEB directs Enbridge Gas to study improvements to the DCF+ test for IRP and encourages Enbridge Gas to consult with the IRP Technical Working Group and to use the IRP pilot projects as a testing ground for an enhanced DCF+ test. In particular, the OEB considers it appropriate for the Technical Working Group to consider how different carbon pricing scenarios should be used in the DCF+ calculation. 4. The OEB directs that Enbridge Gas file an enhanced DCF+ test for approval as part of the first non-pilot IRP Plan
Cross-Subsidization Concerns for Projects Benefiting New Customers	1. The results of the DCF+ test that will be required in the IRP Framework will be of similar assistance as E.B.O. 134 and 188 tests in determining whether a proposed IRP Plan will serve new customers, as they were designed to determine whether a natural gas distribution or transmission expansion project was compatible with the OEB's objective to facilitate rational expansion of transmission and distribution systems. 2. Customer contributions (Contribution in Aid of Construction, System Expansion Surcharge, or Temporary Connection Surcharge) could be applied to an IRP Plan where the IRP Plan is being proposed for the benefit of new customers, to reduce subsidization and improve the NPV and profitability index of an IRP Plan in part 1 of the DCF+ test.

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

As a result of the regulatory and jurisdictional review process, Guidehouse developed the following set of recommendations to improve the DCF+ test according to the OEB Key Findings.

Table 3 – Proposed Parameters to Enhance the DCF+ Test

Recommendation	Rationale (Why?)	Proof point (Fact-based support)	Implications (what it does for the test in a practical way?)
Phase 1 - Avoided/ Incremental Utility Carbon Costs	• To reflect the impact of federal Carbon Pricing Act on the utility's bottom line	• Paying the cost of carbon has become a cost of doing utility business in Ontario • Carbon pricing directly impacts utilities' cash flows • Carbon Pricing Act specifies the pricing for carbon and its evolution over time • Federally legislated	• Addresses the need to account for carbon pricing, per the OEB recommendations from EB-2020-0091 • Reflects Carbon Pricing Act in the DCF+ test • Accounts for all greenhouse gases (tracking $CO2_e$) • \$65 per tonne of $CO2_e$ in 2023, increasing by \$15/tonne of CO2e per year to \$170 per tonne in 2030 • To be differentiated from participating customers' carbon costs to avoid double counting
Phase 2 – Avoided/ Incremental Customer Carbon Costs	• To reflect the impact of federal Carbon Pricing Act on the customer's bottom line • Aimed at the incremental/avoided costs of carbon that industrial/commercial customers will incur due to the adoption of the Facility Alternative project (if any)	• Carbon pricing directly impacts participating customers' cash flows (industrial/commercial) • Carbon Pricing Act specifies the pricing for carbon and its evolution over time • Federally legislated	• Addresses the need to account for carbon pricing, per the OEB recommendations • Reflects carbon pricing act in the DCF+ test • Accounts for all greenhouse gasses (tracking $CO2_e$) • \$65 per tonne of CO2e in 2023, increasing by \$15/tonne of CO2e per year to \$170 per tonne in 2030 • To be differentiated from utility carbon costs to avoid double counting • Excludes net equipment costs, which are calculated and included separately
Phase 2 - Net Equipment Costs	• To distinguish costs associated with the customer-bought equipment from the rest of the customer-incurred costs • To mirror the "Avoided Customer Infrastructure Costs" benefit and specify any equipment costs associated with the NPS-project • To provide more detailed information about parameters that specifically relate to the nature of Facility Alternative projects	• As considered in another Ontario program (CDM costs accounted for in IESO PAC test calculations), and reflected in the NYSEG BCA Handbook (Participant DER cost)	• Differentiates net equipment costs from other customer incurred costs • Risk associated with the possibility of double counting when considering the existing parameter "Incremental Customer Costs"
Phase 3 - NEB Flooring mechanism	• Due to the segregation of the 3 Phases of the DCF+ test and the limitations of Phase III parameter quantification, it is important that Phase 3 NEBs have a base financial	• Concept of having a floor for NEBs is used in other jurisdictions, such as BC, to ensure that NEBs account for a percentage of net DSM portfolio benefits	• Addresses the risk of undercounting non-energy benefits

Recommendation	Rationale (Why?)	Proof point (Fact-based support)	Implications (what it does for the test in a practical way?)
	value (guaranteed by the flooring mechanism) • Adopting the flooring mechanism avoids under-accounting NEBs and ensures that they play a role within the economic feasibility test • Flooring mechanism serves to ensure that Phase 3 NEBs have a minimum financial value	• Out of 5 existing Enbridge Gas projects (not Facility Alternative projects) considered, only 1 would benefit from the adder, as the remaining projects NEBs are higher than 15% of the utility & customer net benefits (Stages 1 and 2) • Note that for this exercise, net benefits were used to assess the utility of the adder, as only the net costs/benefits are provided as part of each stage of the E.B.O. 134 test. However, as part of the DCF+ test, the flooring mechanism will be applied to gross Phase 3 benefits when compared with gross Phases 1 and 2 benefits	• Results in Phase 3 NEBs being (at least) proportional to the gross Phases 1 and 2 benefits • This is a flexible adder, dependent on the gross benefits of Phases 1 and 2, and the quantified Phase 3 benefits • Adder is set at a value such that the Quantifiable Phase 3 NEBs are at least equal to 15% of the gross Phases 1 and 2 benefits • If the quantified Phase 3 NEBs are already greater than 15% of the gross Phases 1 and 2 benefits, then the flooring mechanism is not needed • Quantifiable Benefits Phase 3 ≥ 0.15 * (Gross Benefits Phase 1+ Gross Benefits Phase 2) • It is expected that the need for the flooring mechanism decreases over time, as specific NEBs become quantifiable
Phase 3 - Using 15% for the flooring and accentuating mechanisms	• To ensure that NEBs play a role in the financial analysis at a value that is comparable to what typical NEBs represent in other economic feasibility tests in Ontario and other jurisdictions	• As used in other jurisdictions for DSM, including ON (electricity), BC, and Vermont	• Assigns a financial value to potentially unquantified benefits, per the OEB recommendations from EB-2020-0091 • For the flooring mechanism, the adder ranges between 0% and 15%, as needed to ensure that Phase 3 NEBs are at least equal to the gross Phases 1 and 2 benefits • For the accentuating mechanism, the adder is automatically 15% of quantifiable Phase 3 NEBs, independently of whether they are equal to or larger than the gross Phases 1 and 2 benefits

Recommendation	Rationale (Why?)	Proof point (Fact-based support)	Implications (what it does for the test in a practical way?)
Phase 3 - Accentuating Mechanism	• To account for Phase 3 NEBs that remain unquantifiable at the time that the test is conducted	• Serves the same purpose as single-phase test NEB adders in other jurisdictions, including ON (electricity), BC, and Vermont	• This is a rigid adder that is dependent on the quantified Phase 3 NEBs • Total Benefits Phase 3 = 0.15 * (Quantifiable Benefits Phase 3) • Creates proportionality between the quantifiable and unquantifiable Phase 3 NEBs • The larger the quantifiable Phase 3 NEBs, the larger the impact of Phase 3 Accentuating Mechanism • Stimulates the quantification of Phase 3 NEBs while ensuring that non-quantifiable parameters remain financially considered within the DCF+ test
Phase 3 - Further Refine Quantitative Parameters	• To continue stimulating the refinement of Phase 3 NEBs quantification • Over time, to reduce the need for the Phase 3 flooring mechanism, which quantifies Phase 3 NEBs proportionally to the gross benefits of Phases 1 and 2	• Reflects the intent to develop more precise NEB quantification, instead of relying on other Phases of the DCF+ test or qualified parameters • As done in New York with the BCA Handbook, where individual NEBs have their own formulae, or in the UK, where utilities must develop and share their own formulae for each parameter	• Additional individually quantified NEBs within Phase 3, theoretically reducing the need for the flooring mechanism and making Phase 3 quantification more independent from Phases 1 and 2 • Stimulates the quantification of previously non-quantified NEB parameters • It is recommended to review and update the quantitative parameters as needed annually and include stakeholder review in the process
Phase 3 - Further Refine Qualitative Parameters	• To improve the robustness of qualitative parameters, as they are accounted for in the DCF+ decision-making process • Refer to EB-2020-0091	• As per the DCF+ test, in which non-quantifiable NEBs are considered in the overall economic feasibility analysis process • As done in New York with the BCA Handbook, where individual NEBs that cannot be quantified are mentioned to be qualitatively described (water/land impact), and in Rhode Island (National Grid), where many societal level benefits are qualified (Innovation and knowledge spillover)	• Per EB-2020-0091, qualitative parameters do play a role in the consideration of Facility Alternative projects. This addition will ensure that non-quantifiable NEBs are refined for consideration in the decision-making process • It is recommended to review and update the qualitative parameters as needed annually and include stakeholder review in the process

2. Regulatory Context Review

2.1 E.B.O. 134 and 188 Reports

The Report of the Board on the Expansion of the Natural Gas System in Ontario, the E.B.O. 134 report[3], along with the E.B.O. 188 report, described in the Guidelines for Assessing and Reporting on Natural Gas System Expansion in Ontario[4] provide a description of the tests that form the basis on which the three-phase Discounted Cash Flow economic test (DCF+ test), discussed in this study, is based.

The tests outlined in the E.B.O. 134 and 188 reports were designed to determine whether a natural gas distribution or transmission expansion project is compatible with the Ontario Energy Board's (OEB) objective to facilitate rational expansion of transmission and distribution systems[5].

2.2 E.B.O. 134 Report

The Report of the Board on the Expansion of the Natural Gas System in Ontario, the E.B.O. 134 Report, forms the basis of the filing requirements on the economic feasibility test to be applied to leave to construct applications for pipeline transmission projects. This test, (E.B.O. 134 test) is a three-stage test comprising a Discounted Cash Flow (DCF) analysis as its first stage, and where the second and third stages account for all other quantifiable public interest costs and benefits, and all other relevant public interest factors, respectively.

The DCF analysis, the first component of the proposed three stage E.B.O. 134 test, is a test that relates the net present value of the cash inflows generated from a project to the NPV of its capital costs and other cash outflows. The discounting of cash inflows and outflows gives recognition to the time value of money. Historically, the DCF was utilized by natural gas utilities for a variety of tests (with varying parameters), as reflected in the table below.

Table 4 – Types of Economic Feasibility Tests Utilized by Utilities at Time of E.B.O. 134

Test	Union Gas	Consumers' Gas	I.C.G.
Feasibility Cash Flow Test	N/A	DCF	N/A
Capital Requisition Test	N/A	DCF	N/A
Leave to Construct Test	DCF or 5th Year Rate of Return	5th Year Rate of Return	N/A
Upgrading or Replacing Existing Facilities	N/A	DCF (if quantifiable)	N/A
General Service Test	DCF	N/A	N/A
Contract Customer Test	Pay Back	N/A	N/A
Cost Reduction Test	DCF	N/A	N/A
Earnings and Expense Test	N/A	N/A	5th Year Rate of Return
Comparative Cost Test	5th Year Rate of Return	5th Year Rate of Return	5th Year Rate of Return
Aggregate Customer Net Benefit Test	DCF	DCF	DCF

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[3] Report of the Board on the Expansion of the Natural Gas System in Ontario

[4] The E.B.O. 188 test is described in the OEB's https://www.oeb.ca/oeb/_Documents/Regulatory/EBO%20188%20Decision_AppB_Guidelines.pdf

[5] https://www.rds.oeb.ca/CMWebDrawer/Record/720232/File/document Decision and Order eb-2020-0091 Enbridge Gas Inc. pp. 57

In E.B.O. 134, the OEB directs all utilities to employ the DCF analysis as part of their assessment of the feasibility of projects for system expansion.

Additionally, as part of E.B.O 134, the OEB directed all natural gas utilities to develop a three-stage process to aid the Board in its determination of the public interest[6]. The three stages of the E.B.O. 134 test are described in the E.B.O. 134 Report as follows:

- Stage I: DCF analysis
- Stage II: quantifies other public interest factors not considered at Stage I. All quantifiable other public interest information as to costs and benefits should be provided at this stage.
- Stage III: accounts for all other relevant public interest factors plus the results from Stage I and Stage II.

The E.B.O. 134 states that a project could be accepted if it passes the DCF analysis of stage I, and if the disadvantages and quantifiable costs from stages two and three do not disqualify it. Moreover, if a project is not acceptable because it fails the DCF analysis or has significant other disadvantages, then stages two and three must be completed before the project can be said to be fully evaluated.

In the context of EB-2012-0092, the OEB published the *Filing Guidelines on the Economic Tests for Transmission Pipeline Applications*. These guidelines incorporate the unmodified economic feasibility requirements from the OEB's E.B.O. 134 Report, as well as a new requirement[7]. This new requirement states that any project brought before the Board for approval should be supported by an assessment of the potential impacts of the proposed natural gas pipelines on the existing transportation pipeline infrastructure in Ontario, including an assessment of the impacts on Ontario consumers in terms of cost, rates, reliability, and access to supplies.

2.3 E.B.O. 188 Report

In this report, the OEB introduces guidelines that provide a common analysis and reporting framework to be applied by regulated Ontario Local Distribution Companies (LDCs) to natural gas distribution system expansion (as opposed to the E.B.O. 134 test which is applied to pipeline transmission projects). The E.B.O. 188 report introduced guidelines centered around five main areas: Portfolio Approach, Financial Feasibility Analyses, Reporting, Customer Connection policies, and Environmental Considerations. The information presented in this section were obtained from the E.B.O 188[8] report and Appendix B – Ontario Energy Board Guidelines for Assessing and Reporting on Natural Gas System Expansion in Ontario[9].

Described below are the two main areas pertinent to this engagement: The Portfolio Approach and the Financial Feasibility Analyses.

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[6] E.B.O 134 - Report of the Board on the Expansion of the Natural Gas System in Ontario. Paragraph 6.73, pp.46

[7] https://www.oeb.ca/oeb/_Documents/Regulatory/Ltr_Filing_Guide_Tx_Pipelines_Expansion_20130221.pdf

[8] https://www.oeb.ca/documents/cases/Xo188/decision.pdf

[9] https://www.oeb.ca/oeb/_Documents/Regulatory/EBO%20188%20Decision_AppB_Guidelines.pdf

2.3.1.1 Portfolio Approach

This report introduced the use of a portfolio approach, as opposed to a project-by-project approach to the planning, analysis, management and reporting of distribution expansion projects. The purpose of introducing this approach is to provide the utilities a greater degree of flexibility in determining which projects to undertake while regulatory control is maintained by the Board to ensure no undue cross subsidy or rate impact.

The Portfolio Approach is twofold: it includes the definition of an Investment Portfolio, and a Rolling Project Portfolio.

The Investment Portfolio expansion requires each of the utilities to group into a portfolio (Investment Portfolio) the costs and revenues associated with all new distribution customers who are forecast to attach in a particular test year (including new customers attaching to existing mains). The Investment Portfolio is to include a forecast of normalized system reinforcement costs. The Investment Portfolio ought to be designed to achieve a profitability index (PI) greater than 1.0.

Additionally, each utility must maintain a rolling 12-month distribution expansion portfolio (Rolling Project Portfolio), which is updated monthly, as an ongoing management tool for estimation of the future impacts of capital expenditures associated with distribution system expansion. As part of this initiative, utilities calculate monthly the result of project specific DCF analyses from the past twelve months for the Rolling Project Portfolio. This includes future customer attachments, revenues, and costs based on the life cycle of each of the projects making up the Portfolio.

An overall rolling portfolio PI of 1.0 means that existing customers will not suffer a rate increase over the long term as a result of distribution system expansion. The Board is therefore of the view that an overall portfolio P.I. of 1.0 or better (emphasis added) is in the public interest[10]. However, to ensure fairness and equity in the application and design of contribution requirements, all projects must achieve a minimum threshold PI of 0.8 for inclusion in a utility's Rolling Project Portfolio

2.3.1.2 Financial Feasibility Analyses

The Financial Feasibility Analyses guideline standardizes the elements to be used in the DCF analysis as well as establish the parameters for the costs and revenues that are the inputs to that analysis.

The DCF analysis (E.B.O. 188 test) is used as an economic test for proposed distribution system expansion pipelines and only includes the first stage of the E.B.O. 134 test. In addition to specific test parameters, such as timelines and discount rate definitions, common elements considered in the DCF calculation are classified under three main streams: revenue forecasting, capital costs, and expense forecasting. Below are the mainstream elements as well as parameters specific to the test. For Revenue Forecasting, the common elements are as follows:

a) for the Rolling Project Portfolio, total forecasted customer attachments over the Customer Attachment Horizon for each project

[10] https://www.oeb.ca/documents/cases/Xo188/decision.pdf - pp. 8

b) for the Investment Portfolio, a forecast of all customers to be added in the Test Year

a) an estimate of average use per added customer which reflects the mix of customers to be added

b) a factor which reflects the timing of forecasted customer additions; and

c) rates derived from the existing rate schedules for the utility, net of the gas commodity component

For Capital Costs, the common elements are as follows:

d) an estimate of all costs directly associated with the attachment of the forecast customer additions, including costs of distribution mains, services, customer stations, distribution stations, land, and land rights.

e) an estimate of incremental overheads applicable to distribution expansion at the portfolio level; and

f) an estimate of the normalized system reinforcement costs.

For expense forecasting, the common elements are as follows:

g) gas costs as used in revenue forecasts (excluding commodity costs).

h) incremental operating and maintenance costs

i) income and capital taxes based on tax rates underpinning the existing rate schedules; and

j) municipal property taxes based on projected levels

Specific Parameters to this test include:

a) a 10-year customer attachment horizon

b) a customer revenue horizon of 40 years from the in-service date of the initial mains (20 years for large volume customers)

c) a discount rate equal to the incremental after-tax cost of capital based on the prospective capital mix, debt and preference share cost rates, and the latest approved rate of return on common equity

d) discounting reflecting the true timing of expenditures. Up-front capital expenditures will be discounted at the beginning of the project year and capital expended throughout the year will be mid-year discounted, as will revenue, gas costs, and operating and maintenance expenditures; and

e) gas costs based on the weighted average cost of gas (WACOG) excluding commodity costs

2.4 Enbridge Gas IRP Proceeding EB-2020-0091

On November 1, 2019, Enbridge Gas Inc. (Enbridge Gas) submitted its Integrated Resource Planning proposal to the Ontario Energy Board (OEB). On April 28 ,2020, the OEB issued a Notice of Hearing that resulted in the commencement of Enbridge Gas' IRP proposal review as a separate proceeding: EB-2020-0091.

Accordingly, Enbridge Gas filed an application with the OEB which requested that the OEB determine that the policy direction in its Integrated Resource Planning (IRP) proposal was reasonable and appropriate. Integrated resource planning generally refers to a planning process that evaluates and compares both supply-side and demand-side options to meeting an energy system need. Enbridge Gas indicated that establishing policy guidance for Integrated Resource Planning would enable Enbridge Gas to be successful in considering IRP Alternatives to future facility expansion/reinforcement projects effectively and efficiently. This guidance would also be responsive to previous direction from the OEB that Enbridge Gas should improve its procedures for considering demand-side management as an alternative to pipelines and traditional facility infrastructure.

In its Decision and Order EB-2020-0091, the OEB accepts with modification Enbridge Gas' proposal to utilize a three-phase Discounted Cash Flow economic test (DCF+ test) to compare an IRP Plan or IRP Alternative to a baseline Facility Alternative, such as "future facility expansion/reinforcement projects"[11], as part of the broader IRP Assessment Process. The DCF+ test described in the report is consistent with the principles outlined in E.B.O 134 and E.B.O 188, described in sections 2.1.1 and 2.2.2 of this report, and is part of Step 3 of the IRP Assessment Process (Two-Stage Evaluation Process)

The types of demand-side IRP Alternatives that Enbridge Gas may consider meeting the system needs "target specific constrained areas and encourage the reduction of peak consumption"[12]. Supply-side Alternatives include compressed natural gas and renewable natural gas, commercial or market-based alternatives such as peaking supply, third-party assignments, exchanges, or storage. In Step 3 of the IRP Assessment Process (Two-Stage Evaluation Process), Enbridge Gas proposed to determine whether to proceed with an IRP Plan through a two-stage evaluation. First, Enbridge Gas would conduct a Technical Evaluation (Stage 1) to determine whether potential IRPAs could meet the identified constraint/need. If yes, Enbridge Gas would then proceed with an Economic Evaluation (Stage 2).

2.5 Technical Evaluation

Stage 1 (Technical Evaluation) consists of looking at the technical viability of potentials IRPAs to reduce peak demand to the degree required to meet the identified system need, using best available information to determine whether an IRP Plan including one or more IRPAs would be a viable option[13].

To address the lack of experience with IRPAs and the associated risk of under delivery of peak period savings, Enbridge Gas noted that it may need to employ a derating factor (i.e., assuming less than 100% of the forecast peak demand reduction from the IRPAs would be delivered),

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[11] https://www.rds.oeb.ca/CMWebDrawer/Record/720232/File/document Decision and Order eb-2020-0091 Enbridge Gas Inc. pp. 3

[12] https://www.rds.oeb.ca/CMWebDrawer/Record/720232/File/document Decision and Order eb-2020-0091 Enbridge Gas Inc. pp. 4

[13] https://www.rds.oeb.ca/CMWebDrawer/Record/720232/File/document Decision and Order eb-2020-0091 Enbridge Gas Inc. pp. 49

which would lead Enbridge Gas oversubscribing the amount of IRPAs to have adequate assurance of expected results.

While parties were generally supportive of Enbridge Gas' proposed methodology, several parties commented on Enbridge Gas' intent to use derating factors and:

- questioned the need for oversubscription to IRPAs or submitted that treating this aspect of risk related to IRPAs but not addressing other economic risks associated with facility projects was one-sided, or
- expressed that treating this aspect of risk related to IRPAs but not addressing other economic risks associated with facility projects was one sided

OEB staff submitted that the reliability and economic risks associated with both IRPAs, and Facility Alternatives should be quantified within the subsequent economic evaluation, to the degree possible.

OEB's findings and decision regarding the proposed Technical Evaluation (Stage 1) of the Two-Stage Evaluation Process are as follows:

1. It is appropriate for Enbridge Gas to undertake a technical evaluation to first determine if the IRPAs considered can meet the need, prior to doing an economic evaluation.
2. Accepts that Enbridge Gas may use derating factors or oversubscription of IRPAs to address uncertainty regarding forecast savings (factors being relevant to both technical and economic evaluations).
3. Enbridge Gas should include in its request for OEB approval of specific IRP Plans both for the level of oversubscription and the supporting rationale.

2.6 Economic Evaluation

OEB's findings and decision regarding the proposed Economic Evaluation (Stage 2) of the Two-Stage Evaluation Process are as follows:

1. DCF+ test (including its focus on rate impacts, in its Phase 1), should be the economic evaluation test used in the IRP Framework.
2. DSM and IRP are distinct from each other. The post-2021 DSM Plan should be to assist customers in making their homes and business more efficient in order to better manage their energy bills[14], while IRP is aimed at reducing peak demand in specific geographic areas to replace infrastructure investment with an IRPA investment.
3. Given Economic Evaluation's finding 2, it is reasonable that a different economic test should be applied in the IRP Framework than in the DSM Framework.
4. An IRP Plan is attempting to reduce the long-term cost to all Enbridge Gas customers, and that it is therefore important to have an evaluation test that looks at impacts from the gas customer perspective – this being consistent with OEB's statutory objectives.

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

5. OEB encourages Enbridge Gas to make application to the OEB for approval of the IRP Plan, and then implement and monitor the IRP Plan to make adjustments as appropriate.

Stage 2 is where Enbridge Gas proposed to utilize the DCF+ test to compare the IRP Plan(s) to the baseline Facility Alternative. The primary alternative to the DCF+ test that was considered (suggested by some Intervenors) was the Total-Resource Cost-plus test (TRC+), described below.

2.6.1.1 TRC+ Test

The TRC+ test is a single-phase test that is used in Ontario to assess the cost-effectiveness of Demand Side Management (DSM) programs, by measuring the energy-related benefits and costs of DSM programs experienced by both the gas utility system and participants, as well as an adder that accounts for non-energy benefits (NEBs) associated with DSM programs.[15]

2.6.1.2 DCF+ Test

Based on the E.B.O 134 test and the parameters established by the *Report of the Board on the Expansion of the Natural Gas System in Ontario*[16], the DCF+ test is the three-phase economic test that Enbridge Gas developed to assess the costs and benefits of IRP Plans or IRP Alternatives to a baseline Facility Alternative. The test includes the following three phases:

- Phase one: 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 two: assesses the incremental economic benefits and costs incurred by customers from the IRP Plan(s) or Facility Alternative(s)
- Phase three: assesses the incremental societal benefits and costs

The test includes a forecast of incremental revenues and an estimate of all direct capital costs associated with the IRP Plan, including an estimate for incremental overheads. The existing benefits and costs considered in Enbridge Gas' DCF+ test are presented in the table below.

[15] Ontario Energy Board, Demand Side Management Framework for Natural Gas Distributors (2015- 2020), s.9
[16] http://www.rds.oeb.ca/HPECMWebDrawer/Record/177859/File/document

Table 5 – EB-2020-0091 - Proposed DCF+ Structure

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

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

Economics are evaluated over a period of time, which normally corresponds with the useful life of the asset. The NPV is calculated for each phase, and the results from each phase are presented separately for transparency. A project is deemed economically feasible if the resulting NPV of the three phases of the test summed together is zero or greater. IRP Plans that include some combination of IRPA and facility project (i.e., facility alternative) can also be tested using this approach. Enbridge Gas noted that while economics would be a factor in the final decision as to how best meet a system need, other considerations (safety, public policy, reliability) that are potentially difficult to quantify would also play a role in the final decision as to which IRPA or facility project is selected.

The table below presents examples of costs and benefits that were accounted for in Phase 2 and Phase 3 analyses, in cases dating from 2014 to 2019.

Table 6 – EB-2020-0091 - Examples of Stage 2 and Stage 3 Costs and Benefits between 2014 and 2019

Case Number Project)	Stage 2	Stage 3
EB-2019-0183 (Owen Sound Reinforcement)	• Estimated energy cost savings that accrue directly to Enbridge Gas' in-franchise customers as a result of using natural gas instead of another fuel to meet their energy requirements	• GDP, taxes, and employment impacts (quantifiable) ○ Total: $117M (Appendix A1) • Energy choice options and environmental benefits (less quantifiable)
EB-2018-0306 (Stratford Reinforcement)	• Estimated energy cost savings that accrue directly to Union's in-franchise customers as a result of using natural gas instead of another fuel to meet their energy requirement	• GDP, taxes, and employment impact (quantifiable) ○ Total: $33M (Appendix A2) • Energy choice options and environmental benefits (non-quantifiable)
EB-2018-0013 (Kingsville Reinforcement)	• GHG emission impacts • Estimated energy cost savings that accrue directly to Union's in-franchise customers as a result of using natural gas instead of another fuel to meet their energy requirements	• GDP, taxes, and employment impact (quantifiable) ○ Total: $117M (Appendix A3) • Energy choice options and environmental benefits (non-quantifiable)
EB-2015-0200 (2017 Dawn Parkway Project)	• N/A	• Economic benefits for Ontario, employment, utility taxes (quantifiable) ○ Total: $467M (Appendix A4) • Enhanced security of supply, contribution to a competitive market, enhanced supply choices, and environmental benefits (non-quantifiable)
EB-2014-0261 (2016 Dawn Parkway Expansion)	• N/A	• Economic benefits for Ontario, employment, utility taxes (quantifiable) ○ Total: $378M (Appendix A5) • Security of supply, contribution to a competitive market, enhancement of supply choices, and environmental benefit (non-quantifiable)

Table 7 provides a summary of the arguments that were brought for and against the use of each of the two tests mentioned above in the context of IRP Plan and/or Facility Alternatives.

Table 7 – EB-2020-0091 - TRC+ and DCF+ Tests - Arguments and Counterarguments

Test	Arguments	Counterarguments
TRC+ test	• No other jurisdiction uses a test similar to the DCF+ to compare facility and non-facility options (Several parties) • TRC+ test is the best way to evaluate overall cost-effectiveness of alternatives taking into account all relevant factors (commodity cost savings to customers, and GHG reductions) (Several Parties) • It is not logical to assess demand-side IRPAs using a different economic test than the OEB currently uses to evaluate Enbridge Gas' DSM activities under the DSM Framework (Several Parties)	• The test could require Enbridge Gas customers to pay more for an IRP Plan than they would otherwise have to pay for a pipeline solution that meets the same need (as IRP Plan could score favorably on the TRC+ test, even if the benefits go primarily to customers participating in an IRPA or to society as a whole, not to all Enbridge Gas customers) (Other parties) • TRC+ on its own does not provide any indication of the rate impact or potential for cross-subsidization of the IRP Plans and Facility Alternatives (which are provided in Phase 1 of the DCF+ test) (Enbridge Gas) • Little or no experience using a TRC+ test to evaluate facility projects in the context of meeting system needs (Enbridge Gas)
DCF+ test	• Phase 1 of the DCF+ test serves a gating function, protecting Enbridge Gas customers from the outcome of TRC+ test counterargument 1 (APPRO). • Enbridge Gas has extensive experience using the DCF test (Enbridge Gas)	• Several Parties: Concerns associated with the proposal to add the results of the three phases of the DCF+ test together (Several Parties)

2.7 Hearing Outcome

Conclusions were drawn by all parties in terms of (i) Further Work on Economic Evaluation Methodology, and (ii) Cross-Subsidization Concerns for Projects Benefiting New Customers. Table 8 provides a summary of such conclusions, indicated in OEB's Decision and Order.[17]

Table 8 – EB-2020-0091 - Parties' Conclusions

Party	Further Work on Economic Evaluation Methodology	Cross-Subsidization Concerns for Projects Benefitting New Customers
All Parties	• Further work to be done regarding the specifics of using the preferred test for comparing IRPAs and Facility Alternatives.	
Several Parties	• Propose Enbridge Gas to value avoided GHG emissions in a rising fashion instead of assuming that the price will remain at \$50/tonne CO_2e after 2022	• The existing E.B.O. 188 and E.B.O 134 tests should continue to be required as economic tests to assess whether to proceed with system expansion projects to serve new customers.
Guidehouse	• Existing tests leave gaps and uncertainties about how they would be applied to IRP	
OEB Staff	• Suggests that the economic test should include impacts on Enbridge Gas' supply costs • Should quantify reliability and economic risks if possible	• Enbridge Gas' economic feasibility policies supporting the E.B.O. 188 guidelines enable Enbridge Gas to require a customer contribution, in the form of a Contribution in Aid of Construction, System Expansion Surcharge, or Temporary Connection Surcharge, to address cross-subsidization concerns between new and existing customers (which can improve the NPV and profitability index of a project under the E.B.O 188 test (DCF Phase 1)[18]. This approach could be used for IRPAs. • Enbridge Gas should review its economic feasibility policies to ensure that the system reinforcement costs used as inputs are based on a forward-looking approach that counts for system needs/constrains identified in the Asset Management Plan (AMP), and submit the revised policies in its rebasing application.
Enbridge Gas	• Accepts that parties ought to work to complete a Benefit Cost Analysis Handbook or supplemental guide to E.B.O 134 to improve the comprehensiveness of the DCF+ test for economic evaluations • Could accommodate adding different carbon pricing assumptions (reflecting "Several Parties' Suggestion 1.) • Would take OEB's last suggestion into consideration	• Enbridge Gas would consider including OEB's proposed update (suggestion 2) into its economic feasibility policies to be presented for approval at rebasing, but does not believe that this needs to be ordered by the OEB or included in IRP Framework.

[17] https://www.rds.oeb.ca/CMWebDrawer/Record/720232/File/document Decision and Order eb-2020-0091 Enbridge Gas Inc. pp.54

[18] The most recent version of these policies can be found in EB-2020-0094, Exhibit C, Tab 2, Schedules 1 and 2 for the EGD and Union rate zones

2.8 OEB Findings

The OEB provided findings related to the (i) technical evaluation, (ii) economic evaluation, (iii) further work on economic evaluation methodology, and (iv) cross-subsidization concerns for projects benefiting new customers. These are compiled in Table 9.

Table 9 – EB-2020-0091 - OEB Key Findings

Theme	Findings
Technical Evaluation	1. It is appropriate for Enbridge Gas to undertake a technical evaluation to first determine if the IRPAs considered can meet the need, prior to doing an economic evaluation. 2. Accepts that Enbridge Gas may use derating factors or oversubscription of IRPAs to address uncertainty regarding forecast savings (factors being relevant to both technical and economic evaluations). 3. Enbridge Gas should include in its request for OEB approval of specific IRP Plans both the level of oversubscription and the supporting rationale.
Economic Evaluation	1. DCF+ test (including its focus on rate impacts, in its phase 1), should be the economic evaluation test used in the IRP Framework. 2. DSM and IRP are distinct from each other. The post-2021 DSM Plan should be to assist customers in making their homes and business more efficient in order to better manage their energy bills[19], while IRP is aimed at reducing peak demand in specific geographic areas to replace infrastructure investment with an IRPA investment. 3. Given Economic Evaluation's finding 2, it is reasonable that a different economic test should be applied in the IRP Framework than in the DSM Framework. 4. An IRP Plan is attempting to reduce the long-term cost to all Enbridge Gas customers, and that it is therefore important to have an evaluation test that looks at impacts from the gas customer perspective – this being consistent with OEB's statutory objectives. 5. OEB encourages Enbridge Gas to make application to the OEB for approval of the IRP Plan, and then implement and monitor the IRP Plan to make adjustments as appropriate. 6. Enbridge Gas should be given some discretion in selecting an alternative to meet a system need that does not have the highest score on Phase 1 of the DCF+ test, as there may be considerations or factors that are important in Phases 2 and 3 or are difficult to quantify. However, Enbridge Gas would require full justification of their proposal if they recommend a higher cost alternative.
Further Work on Economic Evaluation Methodology	1. OEB accepts the categories of benefits and costs proposed by Enbridge Gas for the three phases of the DCF+ test for the use of this test in the IRP Framework. 2. The OEB recognizes that the DCF+ test could be improved to better identify and define the costs and benefits of Facility Alternatives and IRPAs, and clarify how these costs and benefits should be considered with the DCF+ test. This could include expanding the inputs to recognize increasing carbon costs, the risk that a constraint remains unresolved, and impact on gas supply costs. 3. The OEB directs Enbridge Gas to study improvements to the DCF+ test for IRP and encourages Enbridge Gas to consult with the IRP Technical Working Group and to use the IRP pilot projects as a testing ground for an enhanced DCF+ test. In particular, the OEB considers it appropriate for the Technical Working Group to consider how different carbon pricing scenarios should be used in the DCF+ calculation. 4. The OEB directs that Enbridge Gas file an enhanced DCF+ test for approval as part of the first non-pilot IRP Plan
Cross-Subsidization Concerns for Projects Benefiting New Customers	1. The results of the DCF+ test that will be required in the IRP Framework will be of similar assistance as E.B.O. 134 and 188 tests in determining whether a proposed IRP Plan will serve new customers, as they were designed to determine whether a natural gas distribution or transmission expansion project was compatible with the OEB's objective to facilitate rational expansion of transmission and distribution systems. 2. Customer contributions (Contribution in Aid of Construction, System Expansion Surcharge, or Temporary Connection Surcharge) could be applied to an IRP Plan where the IRP Plan is being proposed for the benefit of new customers, to reduce subsidization and improve the NPV and profitability index of an IRP Plan in part 1 of the DCF+ test

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

3. Jurisdictional Reviews

Jurisdictions around the globe are commencing to include Non-Pipe Alternatives ("NPAs") into their multi-year integrated resource plans. Part of the feasibility analysis of these solutions is the assessment of their benefits and costs. The purpose of this section is to provide a broader analysis of Benefit-Cost Analyses ("BCA") within natural gas planning, as well as to explore various jurisdictions' efforts with respect to the application of economic tests to NPAs. The jurisdictions that were analyzed were New York, Rhode Island, Massachusetts, and the United Kingdom.

First, an analysis of BCA cost and benefit categories will be presented by referring to efforts conducted in New York, Rhode Island, and the United Kingdom ("UK"). This section provides a general depiction of how infrastructure upgrading, and modernizing efforts are evaluated in terms of their impact to the utility company, its consumers, and the broader society. The second section will explore New York, Rhode Island, and Massachusetts' ongoing efforts to develop costs and benefits specific to NPAs, which are generally included within the broader investment decisions relative to natural gas planning initiatives (described in section 3.1).

3.1 IRP Benefit Cost Analyses for Natural Gas Planning

This section provides examples of the categories of costs and benefits considered across a variety of economic feasibility tests for natural gas integrated resource planning initiatives within three jurisdictions: New York, Rhode Island, and the UK. For each jurisdiction, the context, the costs and benefits, and the associated relevant economic feasibility tests are presented.

3.2 New York - New York State Electric & Gas Corporation and Rochester Gas and Electric Corporation

New York State Electric & Gas Corporation as well as Rochester Gas and Electric Corporation developed and submitted the 2020 Benefit-Cost Analysis (BCA) Handbook V3.0 to provide a "foundational methodology along with valuation assumptions to support a variety of utility programs and projects", covering the following expenditures[20]:

1. Investments in distributed system platform (DSP) capabilities
2. Procurement of distributed energy resources ("DER") through competitive selection
3. Procurement of DER through tariffs
4. Energy efficiency programs

The BCA Handbook is "broadly applicable to all anticipated project types and aims to support companies, developers, and others alike to develop their own BCA model/tools to evaluate a variety of project types"[21].

[20] https://jointutilitiesofny.org/sites/default/files/NYSEG_RGE_2020_DSIP_BCA_Handbook.pdf
[21] https://jointutilitiesofny.org/sites/default/files/NYSEG_RGE_2020_DSIP_BCA_Handbook.pdf, pp. 16

Table 10 and Table 11 present the costs and benefits considered as part of the BCA.

3.2.1.1 Costs

Table 10 – New York – New York State Electric & Gas Corporation and Rochester Gas and Electric Corporation – BCA Costs

Category	Cost	Description
Program Administration		Includes the cost to administer and measure the effect of required program administration performed and funded by utilities and other parties (cost of incentives, measurement and verification, and other program administration costs to start and maintain a program)
Utility-related	Added Ancillary Service Costs	These occur when DER causes additionally ancillary service costs on the system
	Incremental Transmission and Distribution and DSP Costs	These are caused by projects that contribute to the utility's need to build additional infrastructure
Participant-related	Participant DER Cost	Money required to fund programs or measures that is not provided by the utility (equipment and participation costs assumed by DER providers or participants which need to be considered when evaluating the societal costs of a project or program)
	Lost Utility Revenue	Includes the distribution and other non-bypassable revenues that are shifted on to non-participating customers due to the presence of revenue decoupling mechanisms, in which sales-related revenue "losses" due to a decrease in electricity sales or demand is recovered by marginally increasing the rates of electricity sales or demand to non-participating customers
	Shareholder Incentives	Include the annual costs to ratepayers of utility shareholder incentives that are tied to the projects or programs being evaluated
Societal	Net Non-Energy Costs	Determination of the methodology to address a comprehensive listing of applicable elements is complex and not established in the Handbook

3.2.1.2 Benefits

Table 11 – New York – New York State Electric & Gas Corporation and Rochester Gas and Electric Corporation - BCA Benefits

Type	Benefit	Description
Bulk System	Avoided Generation Capacity Costs	These are due to reduced coincident system peak demand
	Avoided LBMP (Locational Based Marginal Price)	Avoided LBMP is avoided energy purchased at the Locational Based Marginal Price (includes energy, congestion, and losses)
	Avoided Transmission Capacity Infrastructure and Related O&M	These benefits result from location-specific load reduction that are valued at the marginal cost of equipment that is avoided or deferred by a DER project or program. Because static forecasts of LBMPs and AGCG values are used, this benefit is only quantified in cases were a measure, project, or portfolio alters the planned transmission system investments from that level embedded in those static forecasts
	Avoided Transmission Losses	These are the benefits that are realized when a project changes the topology of the transmission system that results in a change to the transmission system loss percent
	Avoided Ancillary Services (Spinning Reserves and Frequency Regulation)	These may accrue to selected DERs that are willing and qualify to provide ancillary services. Only quantified in cases where a measure, project, or portfolio is qualified to provide ancillary services to NYISO
	Wholesale Market Price Impact	Includes the benefit from reduced wholesale market prices on both energy (LBMP) and capacity (AGCC) due to a measure, project, or portfolio
Distribution System	Avoided Distribution Capacity Infrastructure	This benefit results from location-specific distribution load reductions that are valued at the marginal cost of distribution system infrastructure that is avoided or deferred by a DER project or program
	Avoided O&M	Includes any benefits incremental to the value captured in the Avoided Distribution Capacity Infrastructure benefit
	Avoided Distribution Losses	This is the incremental benefit that realized when a project changes distribution system losses which in turn result in changes to both annual energy use and peak demand
Reliability/Resiliency	Net Avoided Restoration Costs	They account for avoided costs of restoring power during outages
	Net Avoided Outage Costs	These account for customer outage costs due to a reduction in frequency and duration of outages, then multiplying that expected change by an estimated outage cost
Externalities	Net avoided CO_2	Accounts for avoided CO_2 due to a reduction in system load levels or the increase of CO_2 from onsite generation
	Net avoided SO_2 and NO_x	This benefit includes incremental value of avoided or added emissions
	Avoided Water Impact	Suggested methodology is not included in the BCA Handbook. This impact would be assessed qualitatively
	Avoided Land Impact	Suggested methodology is not included in the BCA Handbook. This impact would be assessed qualitatively
	Net Non-Energy Benefits Related to Utility or Grid Operations	Suggested methodology is not included in the BCA Handbook. This impact would be assessed qualitatively

3.2.1.3 Relevant Tests

According to the outcome of Case 14-M-0101 – Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision, Order Establishing the Benefit-Cost Analysis Framework (issued January 21, 2016)) (BCA Order), benefits and costs identified are to be utilized in three cost tests, presented In Table 12.

Table 12 – New York – New York State Electric & Gas Corporation and Rochester Gas and Electric Corporation – Relevant Tests

Cost Test	Perspective	Question	Approach
Societal Cost Test ("SCT")	Society	Is the state/province better off as a whole?	Compares the costs incurred to design and deliver projects, and customer costs with avoided electricity and other supply-side resource costs (e.g., generation, transmission, and natural gas); also includes the cost of externalities (e.g., carbon emissions and other net non-energy benefits)
Utility Cost Test ("UCT")	Utility	How will utility costs be affected?	Compares the costs incurred to design, deliver, and manage projects by the utility with avoided electricity supply-side resource costs
Ratepayer Impact Measure ("RIM")	Ratepayer	How will utility rates be affected?	Compares utility costs and utility bill reductions with avoided electricity and other supply-side resource costs

The BCA Order positions the Societal Cost Test (SCT) as the primary cost-effectiveness measure because it evaluates impact on society as a whole. On the other hand, "the role of the Utility Cost Test ("UCT"), and the Ratepayer Impact Measure Test (RIM) is to assess the preliminary impact on utility costs and ratepayer bills from the benefits and costs that pass the SCT"[22]. The UCT and the RIM tests help identify projects that may require a more detailed analysis, as some projects may not provide benefits to the utility and ratepayers, despite being beneficial to society as a whole.

External benefits, such as avoided greenhouse gasses, or avoided water and land impacts do not apply to the UCT nor the RIM (as they do not directly impact the utility's operations or utility/customer's bottom-line, and there are no incentives for decreasing emissions or other environmental impacts)

All of the benefits and costs identified in sections 3.2.1.1and 3.2.1.2 are considered as part of the SCT except for the Wholesale Market Price Impacts, the Lost Utility Revenue, and the Shareholder Incentives.

3.3 UK – ofgem

The Office of Gas and Electricity Markets (ofgem) is the government regulator for the electricity and downstream natural gas markets in the United Kingdom (UK). In October of 2021, ofgem developed and published a framework to be used by distribution network operators ("DNOs") to

[22] https://jointutilitiesofny.org/sites/default/files/NYSEG_RGE_2020_DSIP_BCA_Handbook.pdf pp.30

produce BCAs in the context of infrastructure update investment decisions (such as asset replacements, defer replacements, increase utilization of the network)[23].

These guidelines have been developed as part of the broader Network price controls 2021-2028 ("RIIO-ED2") initiative, which, through a collective of regulatory publications[24], sets the outputs that the 14 electricity DNOs in the UK need to deliver for their consumers, as well as the associated revenues they can collect for the five-year period from April 2023 to 31 March 2028. The BCA guidance complements the requirements outlined in the RIIO-ED2 Business Plan Guidance that state that the DNOs must produce and submit BCAs for their interventions on the network[25].

The costs and benefits to be considered in the BCA are those that would occur over and above a baseline scenario (which represents doing nothing or continuing with business as usual).

3.3.1.1 Impacts

Costs must include whole system costs associated with any proposed options (including costs incurred by other electricity network companies). Ofgem directs DNOs to calculate impacts and classify negative impacts of an option as costs and all positive impacts as benefits. Ofgem does not provide guidance regarding the calculations of the impacts, and instead requires each DNO to present their calculations as part of their submission to ofgem.

Table 13 below provides a summary of the impacts that are required to be included in BCAs required by ofgem. All values are to be translated into GBP (£'s).

Table 13 – UK – ofgem – BCA Impacts

<table>
<tr><th>Category</th><th>Cost/Benefit</th><th>Description</th></tr>
<tr><td rowspan="3">DNO – Investment Costs / Avoided Costs</td><td colspan="2">Inspection and Maintenance</td></tr>
<tr><td colspan="2">Asset Replacement</td></tr>
<tr><td colspan="2">Others to be specified by the DNO</td></tr>
<tr><td rowspan="6">(DNO & Non-DNO) Societal Costs/Benefits</td><td>Losses</td><td>Where expenditures are justified using the reduction of electrical energy lost, a standard value for £/MWh lost based on average wholesale electricity prices less the EU Emissions Trading Scheme (ETS) cost of carbon (which is factored into the wholesale price) is provided</td></tr>
<tr><td colspan="2">CO2 associated with losses</td></tr>
<tr><td colspan="2">Customer interruptions</td></tr>
<tr><td colspan="2">Customer minutes lost</td></tr>
<tr><td colspan="2">Other GHG emissions (CO2e) not associated with losses</td></tr>
<tr><td>Fatality</td><td></td></tr>
</table>

[23] https://www.ofgem.gov.uk/sites/default/files/2021-10/RIIO-ED2%20Cost%20Benefit%20Analysis%20Guidance.pdf

[24] https://www.ofgem.gov.uk/energy-policy-and-regulation/policy-and-regulatory-programmes/network-price-controls-2021-2028-riio-2/electricity-distribution-price-control-2023-2028-riio-ed2

[25] https://www.ofgem.gov.uk/sites/default/files/2021-09/ED2%20Business%20Plan%20Guidance%20-%20September%202021_1.pdf

Category	Cost/Benefit	Description
	Major injury	For the benefits associated with preventing fatalities and injuries, DNOs are required to draw on guidance set out in HM Treasury Green Book and the HSE[26,27]
	Oil leakage	N/A

3.4 Rhode Island – National Grid

The development of the Rhode Island Benefit-Cost Framework was identified as a pertinent initiative to this study, especially as it relates to the jurisdiction's ongoing efforts to develop a NPA assessment Framework based on the efforts described below.

In March 2016, the PUC of Rhode Island opened Docket 4600 with the purpose of developing a report to guide the PUC's review of future filings by National Grid, the dominant distribution utility in Rhode Island[28]. A need "to develop an improved understanding of the costs and benefits caused by various activities on the system" originated the need to explore three issues[29].

1. The costs and benefits that can be applied across programs
2. Where in the system, in cost-allocation, and in rates the costs and benefits should be quantified
3. The level of visibility required on the system to best measure the costs and benefits

After a stakeholder engagement process, the PUC adopted the Rhode Island Benefit-Cost Framework as "a tool for measuring the benefits and costs that can be evaluated across:

1. Programs (current and proposed)
2. Technologies (current and proposed)
3. Future utility investment, and
4. Future rate design proposals" [30]

In October 2021, National Grid published its 2022 Rhode Island Test (RI Test) Description as part of its Annual Energy Efficiency Plan for 2022[31]. This test is in line with the latest standards and the Docket 4600A Benefit-Cost Framework and associated guidance (issued in 2017 to

[26] https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/938046/The_Green_Book_2020.pdf

[27] https://www.hse.gov.uk/economics/eauappraisal.htm

[28] https://www.nationalenergyscreeningproject.org/wp-content/uploads/2020/06/Developing_a_Comprehensive_Benefit_Cost_Analysis_Framework_the_Rhode_Island_Experi.pdf

[29] http://www.ripuc.ri.gov/eventsactions/docket/4600-Notice_InviteStakeholders.pdf

[30] http://www.ripuc.ri.gov/eventsactions/docket/4600-NGrid-Ord22851_7-31-17.pdf

[31] http://www.ripuc.ri.gov/eventsactions/docket/5189-NGrid-Energy%20Efficiency%20Plan%202022%20(PUC%2010-1-21).pdf (Appendix 4, pp.389)

clarify, among other things, that the framework applies to “all parties to cases that affect National Grid’s electric rates, not just to the utility”[32]).

Based on the Technical Reference Manual[33], and the Avoided Cost Study[34] (not the National Standards Practice Manual), the RI Test applies to all new and incremental demand side management programs (including energy efficiency programs) to enable the PUC to evaluate and compare their cost-effectiveness. It is independent of the primary fuel or resource the effort focuses on[35].

In total, the Framework provides 34 costs and benefits affecting the utility, consumers, and broader society. Notable costs and benefits, obtained from the 2022 Rhode Island Test Description[36], which are pertinent to this study, are presented in the following sections. Note that the example referred to in the Test Description are based on Energy Efficiency and Active Demand Response Portfolio examples – meaning that costs and benefits may be interchangeable according to the initiative being considered.

3.4.1.1 Costs and Benefits

Table 14 – Rhode Island – National Grid BCA Framework – Costs and Benefits

Category	Cost	Description (Benefit/Cost)	Quantified, Qualified, Not Treated
Power System Level	Energy Supply & Transmission Operating Value of Energy Provided or Saved	Peak savings (Benefit)	Quantified
	Forward Commitment: Capacity Value	Forward capacity avoided costs are included in capacity benefits (Benefit)	Quantified
	Utility / Third Party Developer Renewable Energy, Efficiency, or DER costs	Utility costs to implement the program/portfolio, including planning, administration, marketing, customer incentives, sales technical assistance, training, and evaluation and market research (Cost)	Quantified
	Net risk benefits to utility system operations (generation, transmission, distribution)	Value of improved reliability benefit calculated based on reliability value from AESC 2018 study (Avoided Cost Study) multiplied by energy savings (Benefit)	Quantified
	Option value of individual resources	Additional research necessary to determine applicability and qualitative/quantitative impacts (Benefit or Cost)	Nor Quantified or Qualified
	Investment under uncertainty: real options cost/value	Additional research necessary to determine applicability and qualitative/quantitative impacts (Benefit or Cost)	Nor Quantified or Qualified
	Energy demand reduction induced price effect (DRIPE) (Benefit)	Reduction in prices in energy and capacity markets resulting from the reduction in need for energy and/or capacity due to efficiency and/or demand response programs. Consumers’ investments in energy efficiency avoid both marginal energy production and capital investments, but also lead to structural changes in the market due to lower demand. Over a period of time, the market adjusts to lower demand, but until that time	Quantified

[32] http://www.ripuc.ri.gov/eventsactions/docket/4600A-GuidanceDocument-Final-Clean.pdf

[33] http://rieermc.ri.gov/wp-content/uploads/2019/11/ngrid-ri-2020-trm.pdf

[34] https://www.synapse-energy.com/sites/default/files/AESC%202021_20-068.pdf

[35] http://www.ripuc.ri.gov/eventsactions/docket/5189-NGrid-Energy%20Efficiency%20Plan%202022%20(PUC%2010-1-21).pdf (Appendix 4, pp.392)

[36] http://www.ripuc.ri.gov/eventsactions/docket/5189-NGrid-Energy%20Efficiency%20Plan%202022%20(PUC%2010-1-21).pdf (Appendix 4, pp.414)

Category	Cost	Description (Benefit/Cost)	Quantified, Qualified, Not Treated
		the reduced demand leads to a reduction in the market prices (of electricity in this instance).	
	Greenhouse gas compliance costs & criteria air pollutant and other environmental compliance costs	Cost of compliance with criteria air pollutant regulations, which are not already included in energy costs (Cost)	Quantified
	Innovation and learning by doing	Additional research necessary to determine applicability and qualitative/quantitative impacts. Possible value due to pilots, demonstrations, and assessments of the program/project (Benefit or Cost)	Nor Quantified or Qualified
	Distribution capacity costs	Additional research necessary to determine applicability and qualitative/quantitative impacts (Benefit or Cost)	Nor Quantified or Qualified
	Distribution delivery costs	Additional research necessary to determine applicability and qualitative/quantitative impacts (Benefit or Cost)	Nor Quantified or Qualified
	Distribution system safety loss/gain	Additional research necessary to determine applicability and qualitative/quantitative impacts (Benefit or Cost)	Nor Quantified or Qualified
	Distribution system performance	Additional research necessary to determine applicability and qualitative/quantitative impacts (Benefit or Cost)	Nor Quantified or Qualified
	Utility low income	Reduced arrearages, bad debt write-offs, terminations and reconnections, notices, safety related emergency calls, customer calls and collections, and rate discounts are included as NEIs for income eligible programs. (Benefit)	Quantified
	Distribution system and customer reliability / resilience impacts	Value of Improved Reliability benefit calculated based on reliability value from the AESC study multiplied by the avoided energy savings (in the instance of energy efficiency and demand response measures, in kW)	Benefit
Customer Level	Program participant prosumer benefits / costs	Participant contribution cost is the direct cost of the measure that is not covered by the customer rebate/incentive for energy efficiency measures (Cost)	Quantified
	Low-income participant benefits	Included within the calculation of Non-Energy Impacts as described within the Non-Energy Impacts section of the TRM (Benefit)	Quantified
	Consumer Empowerment & Choice	Additional research necessary to determine applicability and qualitative/quantitative impacts (Benefit or Cost)	Nor Quantified or Qualified
	Non-participant (equity) rate and bill impacts	External to cost effectiveness analysis. (Benefit, but not included in BCA)	Quantified
Societal Level	Greenhouse gas externality costs	Greenhouse gas reduction benefits obtained from the 2021 AESC Study (Benefit)	Quantified
	Criteria air pollutant and other environmental externality costs	Quantified non-embedded NOx reduction benefits obtained from the 2021 AESC Study. Additional research would be required to determine other benefit streams from air pollutants and other environmental externalities (Benefit)	Quantified
	Conservation and community benefits	Additional research necessary to determine applicability and qualitative/quantitative impacts (Benefit or Cost)	Nor Quantified or Qualified
	Non-energy costs/benefits: Economic Development	Economic activity generated by the programs. Non-energy impacts may include – but are not limited to – labor, material, facility use, health and safety, materials handling, property values, and transportation (Benefit)	Qualified
	Innovation and knowledge spillover (related to demonstration projects and	Additional research necessary to determine applicability and qualitative/quantitative impacts (Benefit)	Qualified

Category	Cost	Description (Benefit/Cost)	Quantified, Qualified, Not Treated
	other RD&D preceding larger scale deployment)		
	Societal low-income impacts	Included within the calculation of Non-Energy Impacts as described within the Non-Energy Impacts section of the TRM (Benefit or Cost)	Not Quantified or Qualified
	Public Health	Included within the calculation of Non-Energy Impacts as described within the Non-Energy Impacts section of the TRM (Benefit)	Not Quantified or Qualified
	National Security and international influence	National Security due to avoided oil imports are monetized for residential and income eligible measures that save oil in accordance with the TRM (Benefit)	Quantified

3.5 Costs and Benefits of Pipeline Alternatives in Economic Tests

Considering NPAs within utility planning decision-making efforts is different from other pipe (physical) investments. As energy efficiency programs are rolled out and the use of new types of fuels as considered to reduce, defer, or eliminate physical investments, the associated economic benefits and costs must also be adjusted. Similarly, to existing efforts performed by electric utilities to adjust costs and benefits to Non-Wire Alternatives (NWA), some utilities have commenced to assess categories of costs and benefits that are specific to NPAs, and their quantification methods for use in economic feasibility tests. This section provides a review of such efforts in New York, Rhode Island, and Massachusetts.

3.6 New York – Consolidated Edison, Inc (Con Edison)

In an effort to integrate non pipeline solutions into their portfolio, Con Edison developed in 2018 a Non-Pipeline Solutions (NPS) specific Benefit-Cost Analysis Handbook (NPS BCA Handbook) that aimed to assist in the evaluation of demand-side reductions and/or non-traditional local supply-side additions[37]. This NPS BCA Handbook is based on the Standard BCA Handbook[38], which was first developed by Con Edison in collaboration with the New York Joint Utilities in 2016 to provide consistent and transparent statewide methodologies for electric non-wires solutions and other electric demand-side measures. The BCA methodology outlined in the NPS BCA Handbook is guided by the main principles informing BCA analyses: clear methodologies, striving to identify and evaluate all benefits and costs, evaluating projects and programs within the broader context of a portfolio, addressing the full lifetime of each investment, providing an assessment of the underlying risk of performance of an investment or program via sensitivity analyses, and comparing benefits and costs to traditional alternatives.

In the NPS BCA Handbook, Con Edison defines non-pipeline solutions as “projects or programs that provide incremental gas supply or displace or eliminate customers’ peak day requirements for gas, and do not involve the construction of new pipeline infrastructure”. These projects include the construction of on-system supply resources (e.g., CNG, LNG, or RNG) or the

[37] NPS BCA Draft (2-21-18).pdf, Available at: https://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterCaseNo=17-G-0606&submit=Search

[38] https://www.coned.com/-/media/files/coned/documents/our-energy-future/our-energy-projects/coned-bcah.pdf?la=en

implementation of programs or technologies that reduce customer load requirements, with a focus on peak day needs.

In its Proposal for Use of a Framework to Pursue Non-Pipeline Alternatives to Defer or Eliminate Capital Investment in Certain Traditional Natural Gas Distribution Infrastructure plan issued in 2020[39], Con Edison integrated the NPS BCA Handbook with its standard Handbook and issued a revised handbook (Gas Benefit Cost Analysis Handbook) to evaluate different projects and portfolios of resources across various policy contexts (including energy efficiency programs and non-pipeline solution programs). This handbook, similar to the NPS BCA Handbook, is based on the Electric BCA Handbook[40].

The costs and benefits defined in the NPS BCA Handbook are presented in Tables 15 and Table 16.

3.6.1.1 Costs

Table 15 – New York – Con Edison – NPS BCA Handbook Costs[41]

Category	Cost	Description
Program Administration		Costs to administer and measure a program/project. Includes incentives, measurements and verification, and other program administration costs to start and maintain a specific NPS program (one-time or annual basis)
Incremental Distribution		Costs incurred by the utility to support the project or program. Include incremental distribution system infrastructure costs, including O&M on the distribution system, any capital or other direct expense, opportunity costs associated with any utility owned land or infrastructure granted or dedicated to the project, and indirect administrative costs related to the NPS program.
Lost Utility Revenue		The distribution and other non-bypassable revenues that are shifted on to non-participating customers due to the normal process of establishing rates during a utility rate filing or the presence of revenue decoupling mechanisms. In both instances sales-related revenue shortfalls due to a decrease in natural gas sales or demand is recovered by marginally increasing delivery rates for all customers.
Participant NPS Cost		Costs that would be incurred by providers of NPS services, less incentives recognized in Program Administration Costs. Includes the equipment and participation costs assumed by NPS providers which need to be considered when evaluating the societal costs of a project or program. For the purpose of performing the BCA, Participant NPS costs are applied net of rebates and incentives which have been accounted for under Program Administration costs.
Alternative Fuel Costs (Electricity)		The cost of using an energy source other than gas
External Costs	Alternative Fuel CO_2 Emissions	The emissions generated from production of the alternative fuel and from the end use of the alternative fuel by the consumer
	Alternative Fuel Other Emissions	Covers other emissions costs (other than greenhouse gases) associated with using an energy source other than gas to replace the service provided by gas
	Net Non-Energy Costs	Other, non-commodity impacts on the utility's costs resulting from an NPS project
	Other External Costs	External costs not addressed in other categories, including land and water impacts associated with an NPS program or project

[39] http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7B2CCB0D2A-183A-483B-9F56-87878E0471FA%7D

[40] *https://www.coned.com/-/media/files/coned/documents/our-energy-future/our-energy-projects/coned-bcah.pdf?la=en*

[41] NPS BCA Draft (2-21-18).pdf, pp. 5. Available at: *https://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterCaseNo=17-G-0606&submit=Search*

3.6.1.2 Benefits

Table 16 – New York – Con Edison – NPS BCA Handbook Benefits[42]

Category	Benefit	Description
Fixed and Variable Avoided Upstream Supply	Fixed Costs of Avoided Upstream Supply	Fixed annual expenses, such as for pipeline demand charges or fixed demand fees, associated with securing the right to supply at the city-gate
	Variable Cost of Avoided Upstream Supply	Variable expenses associated with the delivery of actual physical commodity, generally on an as required basis. The specific avoided commodity related benefits of an NPS program or project are a result of the marginal commodity that can be avoided based on the supply portfolio.
Avoided Distribution Expense	Avoided Distribution System Capacity Infrastructure	Result from distribution load reductions (or supply resources) that are valued at the marginal cost of distribution system infrastructure that is avoided or deferred by a NPS project or program
	Avoided Distribution O&M	Includes variable operation and maintenance benefits on the distribution system realized from a proposed program or project. Caution should be exercised in computing these benefits as O&M expenses related to distribution expansions and upgrades are often incorporated into marginal cost studies and the associated avoided cost may already be captured as part of the Avoided Distribution System Capacity Infrastructure cost.
Reliability/Resiliency		Reflects how the NPS programs and projects affect overall system reliability and ability to maintain system standards and recover from system outages.
External Benefits	Avoided Greenhouse Gas Emissions	Accounts for avoided CO2 and other greenhouse gas emissions due to a net reduction in natural gas use or replacement of gas normally delivered by pipeline with Renewable Natural Gas (where greenhouse gas emissions are reduced via the creation of the fuel) or local supplies such as CNG or LNG (where additional emissions may occur in connection with the compression or liquefaction process)
	Other Avoided Emissions	Accounts for the value of avoided pollutant emissions (excluding greenhouse gases emissions)
	Net Non-Energy Benefits	Covers other benefits (or reduced costs) accruing to the utility related to other non-commodity aspects of a proposed project or program
	Other External Benefits	Include external benefits, such as land or water benefits associated with a project or program

[42] NPS BCA Draft (2-21-18).pdf. pp. 7 Available at: https://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterCaseNo=17-G-0606&submit=Search

3.6.1.3 Relevant Tests

After having been identified, evaluated, and present-valued the costs and benefits described previously are applied to three different tests to assess the overall benefit of the project/program[43]. A summary in contained in Table 17.

Table 17 – New York – Con Edison – NPS BCA Handbook Tests

Cost Test	Perspective	Question	Approach
Societal Cost Test (SCT)	Society	Is the state/province better as a whole?	Broadest measure. Includes direct costs and benefits of project (e.g., capital costs, Avoided Upstream Supply Costs, etc.) but also broader externalities associated with the program (e.g., carbon emissions and other net non-energy benefits).
Utility Cost Test (UCT)	Utility	How will utility costs be affected?	Utility focused. Includes costs and benefits applicable to the utility, such as Avoided Upstream Supply Costs, direct capital expenditures, administrative costs, direct incentives paid to participating customers or project participants. Excludes broader societal externalities (e.g., emissions and related costs where these are not a direct charge to the utility)
Ratepayer Impact Measure (RIM)	Ratepayer	How will utility rates be affected?	Customer focused. Recognizes impacts on customers, including non-participating customers. Incorporates secondary implications of projects (e.g., cross subsidization effects) on non-participant bills.

Table 18 presents the costs and benefits that are generally relevant to the above-mentioned tests.

Table 18 – New York – Con Edison – NPS BCA Handbook – Summary of Costs, Benefits and Applicable Tests

Benefit / Cost	SCT	UCT	RIM
Benefits			
Fixed Costs of Avoided Upstream Supply	✓	✓	✓
Commodity Costs of Avoided Upstream Supply	✓	✓	✓
Avoided Distribution System Capacity Infrastructure	✓	✓	✓
Avoided Distribution O&M	✓	✓	✓
Reliability/Resiliency	✓	✓	✓
Avoided Greenhouse Gas Emissions	✓		
Avoided Other Emissions	✓		
Other Non-Energy Benefits	✓	✓	✓
Other External Benefits	✓		
Costs			
Program Administration Costs	✓	✓	✓
Incremental Distribution System Costs	✓	✓	✓
Lost Utility Revenue			✓
Participant NPS Cost	✓	✓	✓
Alternative Fuel Costs (Electric)	✓	✓	✓

[43] NPS BCA Draft (2-21-18).pdf, pp. 21. Available at: https://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterCaseNo=17-G-0606&submit=Search

Alternative Fuel CO2 Emissions	✓		
Alternative Fuel Other Emissions	✓	✓	✓
Other Net Non-Energy Costs	✓	✓	✓
Other External Costs	✓		

3.7 Rhode Island – National Grid

In its 2021-2023 System Reliability Procurement (SRP) Three-Year Plan published in October 2020, National Grid presents its intent to develop a Non-Pipeline Alternative Program Development Plan[44].

The purpose of this initiative, documented in the Docket 5080[45] is “to identify targeted alternative solutions, through customer-side and grid-side opportunities, for the electric and gas distribution systems that are cost-effective, reliable, prudent and environmentally responsible and provide the path to lower supply and delivery costs to customers in Rhode Island.” National Grid’s goal, as the utility, is to identify potential NWA (NWA) and NPA opportunities “to source viable alternative solutions that address system needs and defer, reduce, or remove the need for distribution wires and pipes investments, and to support projects and programs that enable such activity.”

The proposed plan is early stage and under review by the Public Utilities Commission (PUC) as shown in the review timeline below.

Figure 1 – Rhode Island – Timeline of NPA Program Development of National Grid

Regarding Benefit-Cost Analysis criteria and definitions for SRP, National Grid states that “to date, the Company does not have a BCA framework that is applicable to NPAs so one will need to be developed over the course of the SRP Three-Year Plan cycle.” Additionally, National Grid mentions that the NPA BCA will have to align with the general BCA Framework developed as part of Docket 4600[46], which was previously described in Section 3.4 of this report. National Grid will also have to determine a methodology to quantify these costs and benefits for inclusion in economic feasibility tests.

At this time, no benefits, or costs specific to Non-Pipeline Alternatives have been identified in the State of Rhode Island. However, in its SRP 2020 Year-End Report, National Grid provides

[44] http://www.ripuc.ri.gov/eventsactions/docket/5080-NGrid-SRP%202021-2023%20Three-Year%20Plan(11-20-2020)V1.pdf

[45] http://www.ripuc.ri.gov/eventsactions/docket/5080page.html

[46] http://www.ripuc.ri.gov/eventsactions/docket/4600page.html

additional insight on their NPA definition, NPA screening criteria, and the NPA evaluation process[47].

3.7.1.1 Definition of NPA

National Grid defines NPA as "the inclusive term for any targeted investment or activity that is intended to defer, reduce, or remove the need to construct or upgrade components of a natural gas system, or "pipeline investment." Requirements of successful NPA's include passing cost-effectiveness tests and the ability to meet the specified gas system need. Any action, strategy, program, or technology that meets this definition and these requirements is considered an NPA. Examples of these initiatives include demand-side measures, such as demand response, conservation or energy efficiency, and electrification, as well as supply-side measures, such as renewable natural gas (RNG). National Grid notes that "this is not intended to be an exhaustive list of possible demand-side and supply-side solutions. NPA projects can include these and other investments individually or in combination to meet the specified need in a cost-effective manner"[48.]

3.7.1.2 Screening Criteria

Three categories of criteria have been identified by National Grid for the Gas Asset and Design Engineering team to screen potential NPAs during the initial system assessment. Criteria differ based on their application to "small" or "large" projects, as defined below.

- Timeline Suitability
  a) Small Project: start date of implementation is at least 24 months but less than 60 months in the future

  b) Large Project: start date of implementation is at least 36 months but less than 60 months in the future

- Cost Suitability
  a. Small Project: cost of the pipes option is greater than \$0.5M but less or equal to \$2M
  b. Large Project: cost of the pipes option is greater than \$2M
- Reliability of the Gas System
  a. The pipes investment has negligible or no effect on critical reliability of the local or broader gas system. This will be determined through gas system modeling and will be determined based on engineering judgement.

Once the initial screening criteria are met, National Grid notes that projects that are in, or affect "capacity-constrained" locations will be prioritized over other projects that also meet those criteria.

3.8 Massachusetts - AESC 2021 Supplemental Study (Expansion of Natural Gas Benefits)

It was deemed pertinent to this study to mention the ongoing efforts conducted by Massachusetts towards defining NPA-specific costs and benefits, despite them being at a

[47] http://rieermc.ri.gov/wp-content/uploads/2021/05/2020-srp-year-end-report-final-draft-redline.pdf

[48] 20212023 System Reliability Procurement Three Year Plan. pp. 56. Available at: http://www.ripuc.ri.gov/eventsactions/docket/5080-NGrid-SRP%202021-2023%20Three-Year%20Plan(11-20-2020)V1.pdf

nascent stage, as it shows the approach that the utilities in the State are undertaking to achieve a goal similar to Enbridge Gas': improving the economic feasibility assessment procedures (including determining costs and benefits) of NPAs.

Massachusetts does not currently have an integrated gas planning approach. However, the benefit cost framework for energy efficiency (EE) is well established and robust. Since energy efficiency is a component in NPAs, it is instructive to review some aspects of the treatment of benefits for EE, which are included in the 2021 Avoided Cost Study[49], named the AESC 2021 Supplemental Study: Expansion of Natural Gas Benefits[50].

Among the objectives of the supplemental study was the following: "Describing a methodology for calculating avoided costs of localized natural gas transmission and distribution infrastructure." The purpose of this task was to adapt the methodology of calculating avoided costs of localized electric transmission and distribution (T&D) infrastructure to the natural gas sector. The study specifies that this updated methodology is intended to be used during evaluations of NPAs or during long-term resource planning processes (meaning that this content is also pertinent to section 3.1 of this report) to both defer and avoid pipeline system upgrades. While the information presented in the study was limited, it provides some useful insights.

Three main steps were undertaken to perform this study. The first identified target areas and required demand reduction efforts (which is assumed to be known at the time the economic feasibility test is conducted, and therefore not necessary to be explored here). Steps 2 and 3 are discussed below.

To determine benefits of the targeted demand reductions, the supplemental study recommends calculating the avoided T&D costs of an NPA by obtaining the reduced present value of the company's expenditures (multiplying the real carrying capacity charge (RCC) by the total value of the investment).

To calculate the avoided (or deferred) cost, it is recommended for administrators to divide the present value of the benefits from the deferral or avoidance of demand-related expenditures by the demand reduction required to achieve the deferral or avoidance of said expenditures (obtaining a value in $ per dekatherm per day), which could then be translated into a monetary amount in the context of the BCA.

3.9 Treatment of Non-Energy Benefits

Jurisdictions across North America treat NEBs differently in natural gas and electricity planning initiatives. Treatment of NEBs spans along a spectrum ranging from qualification to quantification (percentage allocation or calculations) and is dependent on the program type. Some jurisdictions also distinguish NEBs for low-income communities from broader societal benefits. This section aims to provide an overview of how NEBs are treated across jurisdictions.

Generally, there are four approaches to treating NEBs[51]:

1) Incorporating a "simple, conservative" adder to the benefits

[49] https://www.synapse-energy.com/sites/default/files/AESC%202021_20-068.pdf

[50] https://www.synapse-energy.com/sites/default/files/AESC_2021_Expansion_of_Natural_Gas_Benefits_21-074.pdf

[51] https://sahlln.energyefficiencyforall.org/sites/default/files/2014_%20NEBs%20report%20for%20Maryland.pdf

2) Incorporating “easy to measure” NEBs to the benefits
3) Including and measuring all NEBs
4) Hybrid approach: using an adder along with measuring either easy-to-measure benefits, or as many benefits as possible outside of what is included in the adder; or incorporating a base value for program-invariant NEBs, plus a program-specific adders that incorporates considerations of NEBs in the regulatory environment

Table 19 summarizes the NEB treatment across various jurisdictions, based on Skumatz Economic Research Associates’ *Non-Energy Benefits / Non-Energy Impacts and their Role & Values in Cost-Effectiveness Tests: State of Maryland* Report[52]:

Table 19 – NEBs Treatment Across Jurisdictions (in Regulatory Environment, not gas-specific)

NEB Treatment	Jurisdiction	Value/Parameter
Adder	Indiana	7.5%
	Colorado	10% (25% for low-income)
	Oregon	10%
	Washington	10%
	Vermont	15% (+15% for low-income)
	Ontario (Canada)	15% (TRC+ test only)
	British Columbia (Canada)	15%
Easy to measure	Massachusetts	Includes health and safety, comfort, low-income (NEBs must be reliable and with real economic value)
	Washington	Includes comfort, health, and safety)
	Oregon	Includes value of deferral, water savings
All NEBs are quantified	N/A	N/A
Hybrid	Oregon / Washington	N/A

52 https://sahlln.energyefficiencyforall.org/sites/default/files/2014_%20NEBs%20report%20for%20Maryland.pdf

4. Findings and Recommendations

4.1 Main Findings

4.1.1 Regulatory Context Review

The regulatory context review presented the regulatory background of the DCF+ test. The main findings associated with this section of the study are centered around the nature of the current DCF+ test, its difference with the TRC+ test, and the OEB's findings regarding its use.

4.1.1.1 Existing DCF+

The development of the DCF+ test can be qualified as the product of a multi-year process undertaken by the regulatory parties in Ontario to assess the economic feasibility of different infrastructure and program-related investments. Prior to Enbridge Gas developing the DCF+ test, utilities in Ontario utilized other tests for distribution and transmission infrastructure upgrades. Table 20 presents a comparison of the different tests and their applications.

Table 20 – Key Economic Feasibility Tests

	E.B.O 134 (1988)	E.B.O 188 Test (1998)	TRC+ Test (2015)	DCF+ Test (2020)
Application	Leave to construct applications for pipeline **transmission** projects	Natural gas **distribution system expansion**	Cost-effectiveness of Demand Side Management ("DSM") programs	Compare IRP Plan(s) to baseline Facility Alternative (Enbridge only)
Phases	**Stage I**: DCF Analysis **Stage II**: Quantifies other public interest factors not considered at stage one **Stage III**: Accounts for all other relevant public interest factors plus the results from stage one and stage two	DCF Analysis (for Rolling Project Portfolio)	Single-phase TRC test	**Phase one (1)**: Economic benefits and costs from the utility perspective, **Phase two (2)**: Assesses the incremental economic benefits and costs incurred by customers from the IRP Plan(s) or Facility Alternative(s) **Phase three (3)**: Assesses the incremental societal benefits and costs

The E.B.O. 134 Stage III included both quantitative and qualitative parameters. Historically, while considered in hearings, qualitative parameters did not influence the financial output of the test, creating a potential imbalance of impact between Stages I and II (fully quantified), and Stage III (partially quantified). This same imbalance is currently experienced with the DCF+ test, as its Phase Three also contains quantifiable and non-quantifiable parameters.

As per the table above, the DCF+ is the currently approved three-phase economic test the Enbridge Gas developed to assess the costs and benefits of IRP Plans or IRP Alternatives to a baseline Facility Alternative. Amongst others, IRP Plans and IRP Alternatives can include (the equivalent of) both transmission and distribution upgrades, resulting in a necessity for the DCF+ to encompass the parameters of the E.B.O. 134 and E.B.O 188 tests.

Throughout this study, and as presented during the EB-2020-0091 proceeding[53], it was determined that principles of the DCF+ test were consistent with the ones from the E.B.O 134 and E.B.O 188 tests.

Each phase of the DCF+ test aim to assess the benefits and costs from the perspective of the utility, the users, and the broader society respectively. They include the following parameters:

Table 21 – EB-2020-0091 – Proposed DCF+ Structure

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

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

4.1.1.2 TRC+ vs. DCF+

During the Enbridge Gas IRP Proceeding EB-2020-0091[54], the comparison between the TRC+ and DCF+ was discussed. Table 22 presents the arguments and counterarguments that were brought forward as part of determining whether the TRC+ or the DCF+ tests were a better fit to assess the feasibility of IRP Plans and/or Facility Alternatives.

[53] https://www.rds.oeb.ca/CMWebDrawer/Record/720232/File/document
[54] https://www.rds.oeb.ca/CMWebDrawer/Record/720232/File/document

Table 22 – EB-2020-0091 – TRC+ and DCF+ Tests – Arguments and Counterarguments

Test	Arguments	Counterarguments
TRC+ test	• No other jurisdiction uses a test like the DCF+ to compare facility and non-facility options (Several parties) • TRC+ test is the best way to evaluate overall cost-effectiveness of alternatives taking into account all relevant factors (commodity cost savings to customers, and GHG reductions) (Several Parties) • It is not logical to assess demand-side IRPAs using a different economic test than the OEB currently uses to evaluate Enbridge Gas' DSM activities under the DSM Framework (Several Parties)	• The test could require Enbridge Gas customers to pay more for an IRP Plan than they would otherwise have to pay for a pipeline solution that meets the same need (as IRP Plan could score favorably on the TRC+ test, even if the benefits go primarily to customers participating in an IRPA or to society as a whole, not to all Enbridge Gas customers) (Other parties) • TRC+ on its own does not provide any indication of the rate impact or potential for cross-subsidization of the IRP Plans and Facility Alternatives (which are provided in Phase 1 of the DCF+ test) (Enbridge Gas) • Little or no experience using a TRC+ test to evaluate facility projects in the context of meeting system needs (Enbridge Gas)
DCF+ test	• Phase 1 of the DCF+ test serves a gating function, protecting Enbridge Gas customers from the outcome of TRC+ test counterargument 1 (APPRO) • **Enbridge Gas has extensive experience using the DCF test (Enbridge Gas)**	• Several Parties: Concerns associated with the proposal to add the results of the three phases of the DCF+ test together (Several Parties)

The main concerns associated with the cost and benefit parameters of the test are included within the "arguments" section of the TRC+ test.

4.1.1.3 OEB Findings

The main OEB findings related to this study are presented in Table 23.

Table 23 – EB-2020-0091 – OEB Key Findings

Theme	Findings
Further Work on Economic Evaluation Methodology	1. OEB accepts the categories of benefits and costs proposed by Enbridge Gas for the three phases of the DCF+ test for the use of this test in the IRP Framework. 2. The OEB recognizes that the DCF+ test could be improved to better identify and define the costs and benefits of Facility Alternatives and IRPAs and clarify how these costs and benefits should be considered with the DCF+ test. This could include expanding the inputs to recognize increasing carbon costs, the risk that a constraint remains unresolved, and impact on gas supply costs. 3. The OEB directs Enbridge Gas to study improvements to the DCF+ test for IRP and encourages Enbridge Gas to consult with the IRP Technical Working Group and to use the IRP pilot projects as a testing ground for an enhanced DCF+ test. In particular, the OEB considers it appropriate for the Technical Working Group to consider how different carbon pricing scenarios should be used in the DCF+ calculation. 4. The OEB directs that Enbridge Gas file an enhanced DCF+ test for approval as part of the first non-pilot IRP Plan

While the DCF+ and its cost and benefit categories were selected as the preferred test to compare Facility Alternatives IRPAs to baseline Facility Alternatives, the OEB did recommend

Enbridge Gas to improve the test to better identify and define costs and benefits – including carbon costs, risks for unresolved constraints, and impact on gas supply costs.

Additionally, at the time of the EB-2020-0091 proceeding, Enbridge Gas had proposed to assume that the price will remain at $50/tonne of $CO2_e$ after 2022. Due to the lack of clarity associated with the evolution of carbon pricing in Ontario, the OEB suggested Enbridge Gas "to consider how different carbon pricing scenarios should be used in the DCF+ calculation"[55].

4.1.2 Jurisdictional Review

4.1.2.1 Natural Gas Integrated Resource Planning

Generally, IRPs in the context of natural gas planning encompass a wide range of initiatives and investments. Therefore, BCAs across jurisdictions were deemed both highly detailed and applicable to a wide spectrum of initiatives (some BCAs even include non-gas initiatives, such as New York State Electric & Gas Corporation's BCA Handbook covering distributed system platform capabilities and distributed energy resource investments).

Some jurisdictions provide extensive direction to utilities regarding the quantification of parameters and the methodology to be used. For example, utilities such as New York State Electric and Gas Corporation and Rochester Gas and Electric Corporation provide detailed information regarding the breakdown of costs and benefits, as well as their calculation formulae. On the other hand, other jurisdictions (i.e., ofgem) explicitly provided more agency to utilities to provide the rationale of their calculations and justifications via the requirement to present calculations as part of their submission to ofgem.

It was found that the symmetric treatment of costs and benefits was kept a priority across jurisdictions. In the UK for example, test parameters are not intrinsically defined as costs and benefits. Instead, parameters are defined as "impacts", where negative values are treated as costs, and positive, as benefits.

4.1.2.2 Costs and Benefits of NPAs

When considering NPAs specifically, it was found that current efforts made to implement NPAs and assess their economic viability are still nascent. As opposed to "standard" BCAs in the context of natural gas planning. While some jurisdictions are pursuing pilot programs that include initiatives that could be considered as NPAs (such as Energy Efficiency pilots (like NW Natural), the terminology NPA (or NPS) has not been widely adopted across North American jurisdictions.

Indeed, the definitions of NPAs are not consistent across jurisdictions. They usually include energy efficiency, and demand response measures as well as new supply solutions (RNG, hydrogen blending) and electrification initiatives (water/space heating). They can be defined as "demand-side reductions and non-traditional local supply-side additions" (Con Edison), and "viable alternative solutions that address system needs and defer, reduce, or remove the need for pipes investments" (National Grid).

Jurisdictions NPA economic feasibility tests (and its parameters) are usually developed as an extension of the utility' standard BCA, or as a homologous to NWA BCA. In both cases, special

[55] https://www.rds.oeb.ca/CMWebDrawer/Record/720232/File/document

attention is due to ensure that parameters do not allow for double counting, and that they are adjusted to non-pipe investments.

4.2 Recommendations

4.2.1 Approach

Guidehouse developed the recommendations for the DCF+ test based on the main theme brought forward as part of the OEB Findings while maintaining the integrity of the test and the broader IRP Assessment Process[56]. This approach led to the inclusion of carbon costs in Phases 1 and 2, the consideration of incremental customer equipment costs in Phase 2, and the addition of a two-part non-energy benefit adder (complemented by a continued emphasis of further quantitative and qualitative definition of societal impacts) within Phase 3. As stated in the IRP Assessment process, the DCF+ is used to compare one or more IRP Plans to baseline Facility Alternatives[57]. Guidehouse's proposed changes are therefore applicable to the DCF+ test, when applied to both the IRP Plans and the baseline Facility Alternatives.

Phase 1, 2, and 3 enhancements are summarized in Appendix B.

4.2.2 Proposed Phase 1 Enhancements

4.2.2.1 Avoided / Incremental Utility Carbon Costs

The only proposed Phase 1 enhancement is to include carbon pricing to reflect the impact of the Federal Pricing Act[58] and Ontario's Emissions Performance Standards program[59] (created under the Emissions Performance Standards Regulation[60]) on the utility's bottom line. In the three legislative documents abovementioned, the "portion of a natural gas pipeline system within Ontario that is used in natural gas transmission, including associated installations and equipment" is considered an emitting facility and is subject to carbon pricing.

In terms of its impact on the DCF+ test, this recommendation addresses the need to account for carbon pricing, as per the OEB findings. As opposed to the proposed Phase 2 Carbon Pricing recommendations, Phase 1 Carbon Pricing considerations are only applicable to the utility's emissions (double counting between utility/customer to be avoided). In terms of quantification of costs, Guidehouse recommends Enbridge Gas to follow the applicable charge rate at the time that the DCF+ enhancements are filed (according to the applicable Federal and/or Provincial regulation).

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56 *https://www.rds.oeb.ca/CMWebDrawer/Record/720232/File/document* Decision and Order eb-2020-0091 Enbridge Gas Inc. pp. 49

57 *https://www.rds.oeb.ca/CMWebDrawer/Record/720232/File/document* Decision and Order eb-2020-0091 Enbridge Gas Inc. pp. 49

58 https://laws-lois.justice.gc.ca/eng/acts/G-11.55/

59 https://www.ontario.ca/page/emissions-performance-standards-program

60 https://www.ontario.ca/laws/regulation/190241

4.2.3 Proposed Phase 2 Enhancements

4.2.3.1 Avoided / Incremental Customer Carbon Costs

The first Phase 2 enhancement is to include participating-customer carbon costs. Similarly, to the Avoided / Incremental Utility Carbon Costs proposed in Phase 1, Guidehouse recommends Enbridge Gas to account for (participating) customer-specific carbon costs within Phase 2 of the DCF+ test. Including customer carbon costs would reflect the impact of legislated carbon pricing acts on the customers' bottom line. This enhancement is aimed at all customers that will incur costs due to the adoption of the Facility Alternative project (if any).

Including customer carbon costs addresses the need to account for carbon pricing, as recommended by the OEB. In terms of quantification of costs, Guidehouse recommends Enbridge Gas to follow the applicable charge rate at the time that the DCF+ enhancements are filed (according to the applicable Federal and/or Provincial regulation).

4.2.3.2 Net Equipment Costs

Including net equipment costs as a separate parameter would distinguish costs associated with the customer-bought equipment from the rest of the customer-incurred costs. This enhancement is not deemed critical, as it aims to increase transparency of the test and by recognizing the fact that non-pipeline solutions (as opposed to physical pipeline upgrades) could result in customer-, and equipment-specific costs.

This recommendation is supported by the fact that Net Equipment Costs are also considered in another Ontario program (CDM costs accounted in IESO PAC test calculations[61]) and reflected in the NYSEG BCA Handbook[62].

When considering the existing DCF+ test, this recommendation would differentiate net equipment costs from the other customer incurred costs. Enbridge Gas would have to ensure that double counting between this parameter and the existing *Incremental Customer Costs* parameter is avoided.

4.2.4 Proposed Phase 3 Enhancements

As identified in Section 4.1, despite the qualitative description being considered within the overall DCF+ decision-making process, it was found that there was an opportunity for Phase 3 NEBs to be quantitatively accounted for. This section describes Guidehouse's recommendation to include a two-fold adder. The first mechanism is called the Flooring Mechanism. Its purpose is to ensure that the quantified Phase 3 benefits account for at least 15% of the overall project benefits. The second portion of the adder is called the Accentuating Mechanism. Reflective of NEB adders used in other jurisdictions, the Accentuating Mechanism increases the Phase 3 benefits by 15% to account for unquantified Phase 3 benefits. The parameters included in each of the two proposed Phase 3 enhancements are provided in Appendix B.

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[61] https://www.ieso.ca/-/media/Files/IESO/Document-Library/EMV/CDM_CE-TestGuide.ashx

[62] https://jointutilitiesofny.org/sites/default/files/NYSEG_RGE_2020_DSIP_BCA_Handbook.pdf

4.2.4.1 NEB Adder - NEB Flooring Mechanism

The Flooring Mechanism's purpose is to ensure that quantified NEBs represent at least 15% of the Phases 1 and 2 gross benefits. In other jurisdictions, where single-phase economic feasibility tests are used, it was found that NEBs were accounted for within the economic feasibility analysis through the use of an adder applied on gross project benefits. As the DCF+ test is a three-phase test, project benefits are segregated according to each phase. The flooring mechanism of 15% ensures that, similarly to the use of NEB adders in single-phase tests, the quantified NEBs (Phase 3 benefits) represent at least a specific percentage – 15% – of the gross project benefits (Phases 1 and 2 benefits). The flooring mechanism is therefore flexible. If the gross Phases 1 and 2 benefits are zero and there are no quantified Phase 3 benefits, Phase 3 benefits will remain at zero. The formula of the Flooring Mechanism is as follows:

$$\textbf{Quantifiable Benefits}_{\text{Phase 3}} \geq \textbf{0.15 x (Benefits}_{\text{Phase I}} + \textbf{Benefits}_{\text{Phase II}}\textbf{)}$$

The use of the NEB Flooring Mechanism avoids under-accounting NEBs and stimulates their quantification. If the quantified NEBs of Phase 3 are equal or greater than 15% of Phases 1 and 2 gross benefits, then the flooring mechanism is not required. Over time, Guidehouse expects the need to use the flooring mechanism to decrease, as quantification mechanisms for NEBs are developed.

The Flooring Mechanism is intended to protect against the risk of quantified Phase 3 benefits being insignificant compared to the gross Phases 1 and 2 benefits. If an adder were to be applied only on Phase 3 benefits (similarly to adders in single-phase tests of other jurisdictions) without the flooring mechanism having been previously applied, the adder's impact could be insignificant should there be no quantified Phase 3 benefits (or not enough in cases where there are some known NEBs that cannot be quantified).

The concept of flooring mechanism is also found in British Columbia[63] – in the context of gas DSM, and at a portfolio level. From a conceptual perspective, some of the similarities between the efforts in BC and the DCF+ test is identified as:

- Presence of quantitative and qualitative parameters for non-energy benefits (NEBs)
- Acknowledgement that current quantitative parameters do not encompass the entirety of identified NEBs, requiring the need for an adder
- Acknowledgement that not all projects/programs being considered have a similar degree of NEB quantification
- E.g., More familiar quantifying NEBs for physical infrastructure than for "newer" non-pipeline solution measures
- Expectation that NEBs will become more quantifiable over time

When assessing the applicability of the Flooring Mechanism, Guidehouse referred to five existing Enbridge Gas projects (not facility alternative projects) that had previously been assessed with the E.B.O. 134 test and determined that only one of the projects would benefit from the Flooring Mechanism, as the quantified NEBs (Stage 3 benefits) already represented more than 15% of the projects' utility and customer net benefits (Stages 1 and 2). This analysis

[63] https://www.aceee.org/files/proceedings/2012/data/papers/0193-000258.pdf

was performed by assessing net benefits for each stage of the test. However, in the DCF+, Guidehouse recommends the Flooring Mechanism to be applied to Phase 3 gross benefits when compared to Phases 1 and 2 gross benefits (reflecting the adders used in single phase tests in other jurisdictions, and ensuring the adder is independent of costs and only applied to benefits).

The maximum value of 15% was selected for the Flooring Mechanism to reflect the percentage typically allocated to NEBs in economic feasibility tests in other jurisdictions, including Ontario. The adder ranges between 0% and 15% as needed to ensure that Phase 3 NEBs are at least equal to the gross Phases 1 and 2 benefits.

Using the flooring mechanism as a standalone NEB adder would result in Phase 3 benefits to be proportional to (and therefore dependent on) gross Phases 1 and 2 benefits – representing a risk in terms of the integrity of the test and its three-phase structure. Guidehouse therefore recommends the Flooring Mechanism to be coupled with the Accentuating Mechanism to account for known unquantifiable NEBs, as described in the following section.

4.2.4.2 NEB Adder - Accentuating Mechanism

To account for Phase 3 NEBs that remain unquantifiable at the time that the test is conducted, Guidehouse recommends Enbridge Gas to use a NEB Adder called the Accentuating Mechanism. The Accentuating Mechanism reflects the "typical" NEB adder found in other jurisdictions. It aims to increase previously quantified NEBs by a specific percentage – 15% in this instance – to account for known Phase 3 gross benefits for which there is no quantification mechanism. The equation for the Accentuating Mechanism is as follows:

$$\textbf{Total Benefits}_{\textbf{Phase 3}} = \textbf{0.15 * (Quantifiable Benefits}_{\textbf{Phase 3}}\textbf{)}$$

This is a rigid adder, set at 15%, that is only applied to quantified Phase 3 gross benefits (which, should the flooring mechanism be used, represent at least 15% of overall project benefits). The use of the Accentuating Mechanism creates a sense of proportionality between the quantified and unquantified Phase 3 parameters. The higher the quantified Phase 3 benefits are, the larger the impact of the Accentuating Mechanism will be on overall Phase 3 benefits. The Accentuating Mechanism also decouples the Phase 3 benefits from the rest of the project's benefits (Phase 1 and 2 benefits).

The Accentuating Mechanism will stimulate the efforts to quantify Phase 3 benefits while ensuring that unquantifiable parameters remain financially considered within the DCF+ test. Guidehouse recommends the Accentuating Adder to automatically be 15% of quantifiable Phase 3 gross benefits, independently of whether they are equal or larger than the gross Phases 1 and 2 benefits.

To address the risk associated with the continuous development of quantification techniques of NEBs, Guidehouse recommends Enbridge Gas and its stakeholders to periodically review and update the percentage of the adder, so it best encompasses the unquantified benefits of the selected IRPAs.

4.2.4.3 Further Refining Quantitative Parameters

While recommending Enbridge Gas to adopt the twofold NEB Adder (Flooring and Accentuating Mechanisms), Guidehouse recommends Enbridge Gas to continue refining Phase 3 quantitative parameters, as it reflects an intent to strive for higher degrees of certainty within economic feasibility tests, and ultimately decreases the need for Phase 3 Flooring (first) and Accentuating (after) Mechanisms. Continuing to refine quantitative Phase 3 parameters would independentize Phase 3 parameters from each other.

Guidehouse recommends reviewing and updating the quantitative parameters annually and assess their impact on the NEB Flooring/Accentuating Mechanisms and include stakeholder review in the process.

4.2.4.4 Further Refining Qualitative Parameters

As qualitative parameters are accounted for in the DCF+ decision-making process, Guidehouse recommends Enbridge Gas to explore and further refine the qualitative parameters of the Phase 3 of the DCF+ test. Based on the jurisdictional review, these include, but are not limited to:

- Economic development, including, but not limited to:
    - Indigenous employment
    - Low-income employment
    - Minorities employment
    - Use of Canadian material/equipment/knowledge
- Increased safety
    - For users and operators (including probability of major injury, fatality, leakages)
- Other emissions
    - NO_x
    - SO_x
- Water and land uses
- Resiliency of the transmission and distribution system, or the user's assets
- Reliability of the system (enhanced security of supply)

Other parameters, such as innovation and knowledge spillover, learning by doing or contribution to a competitive market, or even national security and international influence are utilized in other jurisdictions and could be considered on a project per project basis.

Guidehouse recommends ensuring that symmetric treatment of these proposed parameters is kept a guiding principle. Therefore, they are to be considered as costs and benefits depending on the project being considered, for both IRP Plans and baseline Facility Alternatives, as per the IRP Assessment Process.

5. Conclusions

As part of this engagement, Enbridge Gas requested Guidehouse's support to address the OEB's recommendation from EB-2020-0091 to enhance the DCF+ test "to better identify and define the costs and benefits of Facility Alternatives and IRPAs and clarify how these costs and benefits should be considered with the DCF+ test"[64].

The purpose of this study was to conduct regulatory and jurisdictional reviews to assess how the DCF+ test could be improved. The tables below provide the key findings of Guidehouse's research.

Table 24 provides a description of the E.B.O 134 test.

Table 24 – E.B.O 134 Description

E.B.O 134	Stage I	Stage II	Stage III	Notes
Leave to construct applications for pipeline transmission projects	• DCF Analysis	• Quantifies **other public interest factors not considered at Stage I**. All quantifiable other public interest information as to costs and benefits should be provided at this stage.	• Accounts for **all other relevant public interest factors plus the results from Stage I and Stage II**	• The E.B.O. 134 states that a project could be accepted if it passes the DCF analysis of stage I (and if the disadvantages and quantifiable costs from stages two and three do not disqualify it). • If a project is not acceptable because it fails the DCF analysis or has significant other disadvantages, then stages two and three must be completed before the project can be said to be fully evaluated
Discussion Note: The test was originally created to evaluate facility projects. Most projects passed at Stage I. **Inferences:** A project is selected if the NPV of Stage I is greater than 1. If not, Stages II and III are calculated No qualitative parameters				

[64] https://www.rds.oeb.ca/CMWebDrawer/Record/720232/File/document Decision and Order eb-2020-0091 Enbridge Gas Inc.

Table 25 provides a description of the proposed DCF+ test, as per the EB-2020-0091 filing.

Table 25 – EB-2020-0091 - Proposed DCF+ Test

Proposed DCF+ Test	Phase 1	Phase 2	Phase 3	Notes
Three-phase economic test to assess the costs and benefits of IRP Plans or IRP Alternatives to a baseline Facility Alternative	• 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	• Assesses the incremental economic benefits and costs incurred by **customers** from the IRP Plan(s) or Facility Alternative(s)	• Assesses the incremental **societal** benefits and costs	• The NPV is calculated for each phase, and the results from each phase are presented separately for transparency. A project is deemed economically feasible if the resulting NPV of the three phases of the test summed together is zero or greater
Discussion Notes: The original intent of Phase 2 was for participant customers. The original intent phase 3 is for all utility customers and broader society members. **Inferences**: • $NPV_{project} = NPV_{Phase\ 1} + NPV_{Phase\ 2} + NPV_{Phase\ 3}$ • Qualitative parameters also play a role in the final decision as to which IRPA to facility project is selected				

Table 26 compiles the key OEB findings that led to this engagement being pursued.

Table 26 – EB-2020-0091 Key OEB Findings

OEB Findings
• The OEB finds that Enbridge Gas should be given some discretion in selecting an alternative to meet a system need that does not have the highest score on phase 1 of the DCF+ test, as there may be considerations or factors that are important in Phases 2 or 3 or are difficult to quantify. However, Enbridge Gas will require full justification of their proposal if they recommend a higher cost alternative • The OEB recognizes that the DCF+ test could be improved to better identify and define the costs and benefits of Facility Alternatives and IRPAs and clarify how these costs and benefits should be considered within the DCF+ test. This could include expanding the inputs to recognize increasing carbon costs, the risk that a constraint remains unresolved, and impact on gas supply costs. The OEB directs Enbridge Gas to study improvements to the DCF+ test for IRP
Inferences: Improvements to the DCF+ are centered around cost and benefit parameter improvement while maintaining the structure of the DCF+ test

Table 27 contains Guidehouse's recommendations

Table 27 – Proposed Parameters to Enhance the DCF+ Test

Proposed Enhanced DCF+ Test	Phase 1	Phase 2	Phase 3
Recommendations	• Include avoided/incremental utility carbon costs	• Include avoided/incremental participating **customer** carbon costs • Specify incremental customer equipment costs • Defined as the capital and operating and maintenance costs associated with the purchase of equipment that may be required as part of the Facility Alternative project (if any)	• Flooring brings quantified Phase 3 non-energy benefits (NEBs) to at least 15% of Phases 1 and 2 benefits • If Phase 3 quantifiable benefits > 15% of Phases I and II benefits, then no flooring needed • NEB Adder of 15% (Accentuating Mechanism) is applied to quantified Phase 3 benefits to include qualitative parameters • Further refine qualitative and quantitative parameters
Rationales	• Maintains 2020 proposed DCF+ test concept that Phase 1 reflects Utility Costs & Benefits	• Maintains 2020 proposed DCF+ test concept that Phase 2 reflects **Customer** Costs & Benefits	• Maintains 2020 proposed DCF+ test concept that Phase 3 reflects **Societal** Costs & Benefits
	• Concretization of federal and provincial carbon pricing regulation structures	• Concretization of federal and provincial carbon pricing regulation structures • Consistency as performed in other jurisdictions	• As per other jurisdictions • To assign quantitative value to qualitative parameters and stimulate the quantification of NEBs
Implications	• Provides movement toward OEB recommendations on 2020 Proposed DCF + test (inclusion of societal benefits) • Inclusion of carbon costs in Phase 1, Phase 2 demonstrates alignment with Federal Public Policy • Does not directly address the impact on gas supply costs • Demonstrates inclusion of IRP and Facility Alternatives costs and benefits considered in other jurisdictions		
Next steps	• Need to define carbon accounting boundaries (scope 1, 2, 3)		• Specify defining parameters of the flooring adder & NEB (accentuating mechanism) adders • Refinement of qualitative & quantitative parameters
	• Define and agree on Phase 1 Utility carbon costs	• Define and agree on Phase 2 Customer Carbon costs • Ensure that net equipment costs are distinguished from other existing parameters, such as incremental customer costs	
Issues	• *How will we ensure that carbon costs are not double counted between Phases I and II?*	• *How do net equipment costs differ from incremental customer costs?*	

6. Next Steps

For next steps, Guidehouse recommends Enbridge Gas to explore the applicability of the recommendations by conducting an internal stakeholder review, and to test the recommendations with internal project documentation. Guidehouse also recommends Enbridge Gas to work on defining the Scope boundaries between Phase 1 and 2 carbon costs to avoid double counting, to further refine the definition of the added parameter *Customer Equipment* Costs, and to select the Phase 3 parameters that will be subject to further quantitative and qualitative refinement.

Appendix A – Three-stage Economic Feasibility Test – Stage 3 Calculations

Appendix A1 - EB-2019-0183 (Owen Sound Reinforcement)[65]

The economic benefits for Ontario were estimated to be $71M. This is related only to the construction of the Project and does not include the similar direct and indirect economic benefits to Ontario when the gas customers invest and grow their operations. Factors that contributed to this amount are:

- Employment: Additional employment of persons directly involved in the construction of the project as well as the trickledown effect on employment. Total jobs estimated to be created: 894.

- Utility Taxes: These encompass the taxes that Union Gas would pay to the various levels of government (Ontario income taxes, municipal taxes). The NPV of Ontario income taxes and municipal taxes payable by Union related to the Project of the project life is approximately $10M with a further $4M paid to the Federal Government.

- Employer Health Taxes: The additional employment that will result from the construction of the Project will generate additional employer health tax payments to aid in covering the cost of providing health services in Ontario.

Other costs and benefits, such as the environmental effects of the project, were described but not quantified.

The summary of Stages 1 to 3 are as follows:

Table 28 – EB-2019-0183 - Summary of Stage 1 to Stage 3 NPVs

Stage	NPV ($M)
Stage 1	(38)
Stage 2	+269 to 405
Stage 3	+71
Total	**+302 to 438**

65 https://www.rds.oeb.ca/CMWebDrawer/Record/651148/File/document

The breakdown of the Stage 3 calculations is as follows:

Owen Sound Reinforcement
Economic Benefits from Infrastructure Spending

Figures in $ Millions

Line No	Description	Capex Spend Out of Country (a)	Capex Spend within Ontario (b)	Capex Spend within Canada Excluding Ontario (c)	Capex Total * (d)= sum (a-c)	
1	Proposed Facilities	$ 1	$ 54	$ 6	$ 60.1	
2						
3	% of Total Spend	1%	89%	9%	100%	Line 1 /Total Line 1 Col (d)
4						
5	GDP					
6	GDP Factor		1.14			
7	GDP Impact $ Millions		$ 61			Line 1 * Line 6
8						
9	Employment (Jobs)					
10	Jobs Factor		16.7			
11	Jobs Created		894			Line 1 * Line 10
12						
13	Taxes Paid by Enbridge Gas					
14	Property Tax		$ 4			Source: NPV DCF
15	Provincial Income Tax		$ 6			Source: NPV DCF
16	Total Provincial Taxes		$ 10			
17	Federal Income Tax		$ 4			Source: NPV DCF
18	Total Taxes Paid		$ 14			
19						
20	Total Value to Ontario					
21	GDP Impact $ Millions		$ 61			Line 7
22	Total Provincial Taxes		$ 10			Line 16
23	NPV Total Value to Ontario		$ 71			

* excludes indirect overheads

Figure 2 – EB-2019-0183 - Stage 3 Benefits Calculations

Appendix A2 - EB- 2018-0306 (Stratford Reinforcement)[66]

The economic benefits for Ontario were estimated to be $33M. This is related only to the construction of the Project and does not include the similar direct and indirect economic benefits to Ontario when the gas customers invest and grow their operations. Factors that contributed to this amount are:

- Employment: Additional employment of persons directly involved in the construction of the project as well as the trickledown effect on employment. Total jobs estimated to be created: 415.

- Utility Taxes: These encompass the taxes that Union Gas would pay to the various levels of government (Ontario income taxes, municipal taxes). The NPV of Ontario income taxes and municipal taxes payable by Union related to the Project of the project life is approximately $5M with a further $2M paid to the Federal Government.

- Employer Health Taxes: The additional employment that will result from the construction of the Project will generate additional employer health tax payments to aid in covering the cost of providing health services in Ontario.

Other costs and benefits, such as the environmental effects of the project, were described but not quantified.

The summary of Stages 1 to 3 is as follows:

Table 29 – EB-2018-0306 - Summary of Stage 1 to Stage 3 NPVs

Stage	NPV ($M)
Stage 1	(20)
Stage 2	+175 to 282
Stage 3	+33
Total	**+188 to 295**

66 https://www.rds.oeb.ca/CMWebDrawer/Record/625055/File/document

The breakdown of the Stage 3 calculations is as follows:

Stratford Reinforcement Project
Economic Benefits from Infrastructure Spending
Figures in $ Millions

Line No	Description	Capex Spend Out of Country	Capex Spend within Ontario	Capex Spend within Canada Excluding Ontario	Capex Total	
		(a)	(b)	(c)	(d)= sum (a-c)	
1	Proposed Facilities	$ 0.3	$ 24.8	$ 3.4	$ 28.5	
2						
3	% of Total Spend	1%	87%	12%	100%	Line 1 /Total Line 1 Col (d)
4						
5	GDP					
6	GDP Factor		1.14			
7	GDP Impact $ Millions		$ 28			Line 1 * Line 6
8						
9	Employment (Jobs)					
10	Jobs Factor		16.7			
11	Jobs Created		415			Line 1 * Line 10
12						
13	Taxes Paid by Union Gas					
14	Property Tax		$ 2			Source: NPV DCF
15	Provincial Income Tax		$ 3			Source: NPV DCF
16	Total Provincial Taxes		$ 5			
17	Federal Income Tax		$ 2			Source: NPV DCF
18	Total Taxes Paid		$ 7			
19						
20	Total Value to Ontario					
21	GDP Impact $ Millions		$ 28			Line 7
22	Total Provincial Taxes		$ 5			Line 16
23	NPV Total Value to Ontario		$ 33			

Figure 3 – EB-2018-0306 - Stage 3 Benefits Calculations

Appendix A3 - EB-2018-0013 (Owen Sound Reinforcement)[67]

The economic benefits for Ontario were estimated to be $117M. This is related only to the construction of the Project and does not include the similar direct and indirect economic benefits to Ontario when the gas customers invest and grow their operations. Factors that contributed to this amount are:

- Employment: Additional employment of persons directly involved in the construction of the project as well as the trickledown effect on employment. Total jobs estimated to be created: 1,615.
- Utility Taxes: These encompass the taxes that Union Gas would pay to the various levels of government (Ontario income taxes, municipal taxes). The NPV of Ontario income taxes and municipal taxes payable by Union related to the Project of the project life is approximately $7M with a further $2M paid to the Federal Government.
- Employer Health Taxes: The additional employment that will result from the construction of the Project will generate additional employer health tax payments to aid in covering the cost of providing health services in Ontario.

Other costs and benefits, such as the environmental effects of the project, were described but not quantified. A list of 4 inherent advantages of natural gas was provided.

The summary of Stages 1 to 3 are as follows:

Table 30 – EB-2018-0013 - Summary of Stage 1 to Stage 3 NPVs

Stage	NPV ($M)
Stage 1	(59)
Stage 2	+283 to 639
Stage 3	+117
Total	**+341 to 697**

[67] https://www.rds.oeb.ca/CMWebDrawer/Record/597854/File/document

The breakdown of the Stage 3 calculations is as follows:

Kingsville Transmission Reinforcement Project (KTRP)
Economic Benefits from Infrastructure Spending
Figures in $ Millions

Line No	Description	Capex Spend Out of Country (a)	Capex Spend within Ontario (b)	Capex Spend within Canada Excluding Ontario (c)	Capex Total (d)= sum (a-c)	
1	Proposed Facilities	$ 8	$ 97	$ 1	$ 105.7	
2						
3	% of Total Spend	8%	91%	1%	100%	Line 1 /Total Line 1 Col (d)
4						
5	GDP					
6	GDP Factor		1.14			
7	GDP Impact $ Millions		$ 110			Line 1 * Line 6
8						
9	Employment (Jobs)					
10	Jobs Factor		16.7			
11	Jobs Created		1,615			Line 1 * Line 10
12						
13	Taxes Paid by Union Gas					
14	Property Tax		$ 4			Source: NPV DCF
15	Provincial Income Tax		$ 3			Source: NPV DCF
16	Total Provincial Taxes		$ 7			
17	Federal Income Tax		$ 2			Source: NPV DCF
18	Total Taxes Paid		$ 9			
19						
20	Total Value to Ontario					
21	GDP Impact $ Millions		$ 110			Line 7
22	Total Provincial Taxes		$ 7			Line 16
23	NPV Total Value to Ontario		$ 117			

Figure 4 – EB-2019-0183 - Stage 3 Benefits Calculations

Appendix A4 - EB-2015-0200 (2017 Dawn Parkway Project)[68]

The economic benefits for Ontario were estimated to be $467M. This is related only to the construction of the Project and does not include the similar direct and indirect economic benefits to Ontario when the gas customers invest and grow their operations. Factors that contributed to this amount are:

- Employment: Additional employment of persons directly involved in the construction of the project as well as the trickledown effect on employment. Total jobs estimated to be created: 6,300.

- Utility Taxes: These encompass the taxes that Union Gas would pay to the various levels of government (Ontario income taxes, municipal taxes). The NPV of Ontario income taxes and municipal taxes payable by Union related to the Project of the project life is approximately $28M with a further $10M paid to the Federal Government.

- Employer Health Taxes: The additional employment that will result from the construction of the Project will generate additional employer health tax payments to aid in covering the cost of providing health services in Ontario.

Other costs and benefits, such as the environmental effects of the project, the enhanced supply choices, the contribution to a competitive market, and the enhanced security of supply were described but not quantified.

The summary of Stages 1 to 3 are as follows:

Table 31 – EB-2015-0200 - Summary of Stage 1 to Stage 3 NPVs

Stage	NPV ($M)
Stage 1	(344)
Stage 2	N/A
Stage 3	+467
Total	**+123**

[68] https://www.rds.oeb.ca/CMWebDrawer/Record/485054/File/document

The breakdown of the Stage 3 calculations is as follows:

Economic Benefits from Infrastructure Spending

Figures in $ Millions

Line No	Description	Note	Capex Spend Out of Country	Capex Spend within Ontario	Capex Spend within Canada Excluding Ontario	Capex Total	
			(a)	(b)	(c)	(d)= sum (a-c)	
1	Dawn H		$ 58	$ 163	$ 29	$ 250	
2	Lobo D		$ 58	$ 73	$ 14	$ 145	
3	Bright C		$ 59	$ 140	$ 29	$ 228	
4	Total		$ 175	$ 376	$ 72	$ 623	
5							
6	% of Total Spend		28%	60%	12%	100%	Line 4 /Total Line 4 Col (d)
7							
8	GDP						
9	GDP Factor	(a)		1.14			Source : Schedule 9-8
10	GDP Impact $ Millions			$ 429			Line 4 * Line 9
11							
12	Employment (Jobs)						
13	Jobs Factor	(b)		16.7			Source : Schedule 9-8
14	Jobs Created			6,279			Line 4 * Line 13
15							
16	Taxes Paid by Union Gas	(c)					
17	Property Tax			$ 15			Source: NPV DCF
18	Provincial Income Tax			$ 23			Source: NPV DCF
19	Total Provincial Taxes			$ 38			
20	Federal Income Tax			$ 30			Source: NPV DCF
21	Total Taxes Paid			$ 68			
22							
23	Total Value to Ontario						
24	GDP Impact $ Millions			$ 429			Line 10
25	Total Provincial Taxes			$ 38			Line 19
26	NPV Total Value to Ontario			$ 467			

Notes:
Schedule 9-8 : The Economic Impact of Ontario's Infrastructure Investment Program Conference Board of Canada
(a) Schedule 9-8 page 7 ($ Real GDP $ 114 million for each $ 100 million invested)= 1.14
(b) Schedule 9-8 page 7 (1,670 jobs for each $ 100 million invested) = 1670/100 = 16.70 per $ 1million
(c) Net Present Value taxes by Union paid over 30 years

Figure 5 – EB-2015-0200 - Stage 3 Benefits Calculations

Appendix A5 - EB-2014-0261 (Dawn Parkway 2016 Expansion Project)[69]

The economic benefits for Ontario were estimated to be $378M. This is related only to the construction of the Project and does not include the similar direct and indirect economic benefits to Ontario when the gas customers invest and grow their operations. Factors that contributed to this amount are:

- Employment: Additional employment of persons directly involved in the construction of the project as well as the trickledown effect on employment. Total jobs estimated to be created: 5,000.

- Utility Taxes: These encompass the taxes that Union Gas would pay to the various levels of government (Ontario income taxes, municipal taxes). The NPV of Ontario income taxes and municipal taxes payable by Union related to the Project of the project life is approximately $34M with a further $22M paid to the Federal Government.

- Employer Health Taxes: The additional employment that will result from the construction of the Project will generate additional employer health tax payments to aid in covering the cost of providing health services in Ontario.

Other costs and benefits, such as the environmental effects of the project, the enhanced supply choices, the contribution to a competitive market, and the enhanced security of supply were described but not quantified.

The summary of Stages 1 to 3 are as follows:

Table 32 – EB-2014-0261 - Summary of Stage 1 to Stage 3 NPVs

Stage	NPV ($M)
Stage 1	(259)
Stage 2	N/A
Stage 3	+378
Total	**+119**

[69] https://www.rds.oeb.ca/CMWebDrawer/Record/451211/File/document

The breakdown of the Stage 3 calculations is as follows:

Economic Benefits from Infrastructure Spending

Figures in $ Millions

Line No	Description	Note	Capex Spend Out of Country	Capex Spend within Ontario	Capex Spend within Canada Excluding Ontario	Capex Total	
			(a)	(b)	(c)	(d)= sum (a-c)	
1	Lobo C		$ 41	$ 109	$ 20	$ 170	
2	Hamilton-Milton		$ 32	$ 193	$ 21	$ 246	
3	Total		$ 73	$ 301	$ 41	$ 416	
4							
5	% of Total Spend		18%	73%	10%	100%	Line 3 /Total Line 3 Col (d)
6							
7	GDP						
8	GDP Factor	(a)		1.14			Source : Schedule 9-8
9	GDP Impact $ Millions			$ 344			Line 3 * Line 8
10							
11	Employment (Jobs)						
12	Jobs Factor	(b)		16.7			Source : Schedule 9-8
13	Jobs Created			5,033			Line 3 * Line 12
14							
15	Taxes Paid by Union Gas	(c)					
16	Property Tax			$ 17			Source: NPV DCF
17	Provincial Income Tax			$ 17			Source: NPV DCF
18	Total Provincial Taxes			$ 34			
19	Federal Income Tax			$ 22			Source: NPV DCF
20	Total Taxes Paid			$ 56			
21							
22	Total Value to Ontario						
23	GDP Impact $ Millions			$ 344			Line 9
24	Total Provincial Taxes			$ 34			Line 18
25	NPV Total Value to Ontario			$ 378			

Notes:
Schedule 9-8 : The Economic Impact of Ontario's Infrastructure Investment Program Conference Board of Canada
(a) Schedule 9-8 page 7 ($ Real GDP $ 114 million for each $ 100 million invested)= 1.14
(b) Schedule 9-8 page 7 (1,670 jobs for each $ 100 million invested) = 1670/100 = 16.70 per $ 1million
(c) Net Present Value taxes by Union paid over 30 years

Figure 6 – EB-2014-0261 - Stage 3 Benefits Calculations

Appendix B – DCF+ Test Parameters

In **bold and underlined** are the Guidehouse recommended enhancements.

Benefit / Cost	DCF+ Phase I	Enhanced DCF+ Phase I	DCF+ Phase II	Enhanced DCF+ Phase II	DCF+ Phase III	Enhanced DCF+ Phase III
Benefits						
Incremental Revenues	✓	✓				
Avoided Utility Infrastructure Costs	✓	✓				
Avoided Customer Infrastructure Costs			✓	✓		
Avoided Utility Commodity/Fuel Costs	✓	✓				
Avoided Customer Commodity/Fuel Costs			✓	✓		
Avoided O&M	✓	✓				
Avoided Greenhouse Gas Emissions						
- ***Avoided Utility Carbon Costs***		**✓**	✓			
- ***Avoided Customer Carbon Costs***				**✓**		
Other External Non-Energy Benefits					✓	
*Quantifiable NEBs **(c/w flooring mechanism)***					✓	**✓**
- Utility & Employer Health Taxes					✓	✓*
- Economic Development					✓	✓*
- Employment (w/ low income)					✓	✓*
*15% Non-Energy Benefit Adder (**Accentuating Mechanism**) for **unquantifiable** NEBs*						**✓**
- Reliability / Resiliency						**✓***
- Enhanced Supply Choices						**✓***
- Environmental Effects on Society (such as air pollution)						**✓***
- Contribution to a competitive market						**✓***
- Increased Safety						**✓***
Costs						
Incremental Capital Expenditure	✓	✓				
Incremental Operations & Maintenance	✓	✓				
Incremental Taxes	✓	✓				
Incremental Utility Commodity/Fuel Costs	✓	✓				
Incremental Customer Commodity/Fuel Costs			✓	✓		
Incremental Greenhouse Gas Emissions				✓		
- ***Incremental Utility Carbon Costs***		**✓**	✓			
- ***Incremental Customer Carbon Costs***				**✓**		
Incremental Customer Costs			✓	✓		
Incremental Customer Equipment Costs				**✓**		
Other External Non-Energy Costs					✓	

* Project-dependent (include only if applicable)