EB-2022-0200

ONTARIO ENERGY BOARD

IN THE MATTER OF the *Ontario Energy Board Act, 1998*, S.O. 1998, c.15 (Schedule. B);

AND IN THE MATTER OF an Application by Enbridge Gas Inc., pursuant to section 36(1) of the *Ontario Energy Board Act, 1998,* for an order or orders approving or fixing just and reasonable rates and other charges for the sale, distribution, transmission and storage of gas as of January 1, 2024

COMPENDIUM OF THE SCHOOL ENERGY COALITION
(EGI - Customer Attachment Policies Panel)

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Table 6
2024 Investments Not Subject to LTC

Asset Class	Investment Code	Investment Name	2024 Forecast	2023 to 2032 Forecast
TIS	102115	eGIS / GPS Hardware lifecycle 2024	$2,176,948	$2,176,948

/u

7.3 Customer Additions and Profitability Index Values

Customer Connections Feasibility

97. Enbridge Gas expands its distribution system in accordance with the OEB's guidelines for the expansion of natural gas service. These guidelines are articulated in the E.B.O 188 report.[27] The intent of E.B.O 188 is to facilitate rational expansion of natural gas service while protecting existing customers from undue cross-subsidization.

98. For the general service market, Enbridge Gas uses a portfolio approach (i.e., Investment Portfolio and Rolling Project Portfolio) to manage distribution system expansion activities and ensure that required profitability standards are achieved at both the individual project and the portfolio level.

99. If the expansion is driven by large commercial/industrial customers (contract market), the feasibility analysis factors in the incremental cost and revenue of the customers on the project and determines whether the customers would be required to pay a Contribution in Aid of Construction (CIAC). This is explained in more detail in the Feasibility Process below.

[27] E.B.O 188 Final Report of the Board, January 30, 1998.

Investment Portfolio

100. This approach evaluates feasibility on all proposed new distribution customer attachments for a test year. The portfolio includes the costs and revenues associated with all new distribution customers forecasted to be attached in a particular year (including new customers attaching to existing main or infill services). The investment portfolio is designed by including a safety margin to mitigate the forecast risk and achieve a PI threshold greater than 1.0 with the purpose of reducing undue cross-subsidization.

Rolling Project Portfolio (RPP)

101. This approach maintains a portfolio of system expansion projects over a rolling 12-month period. The RPP is used as a management tool for estimating the future impact of capital expenditures associated with system expansion. The RPP excludes customers attaching to existing mains (infill services). The RPP is required to achieve a PI threshold greater than 1.0.

Feasibility Process

102. When assessing the feasibility of a new project, Enbridge Gas prepares a forecast of project costs and revenues for calculating Profitability Index (PI) using the formula below.[28]

$$\text{Profitability Index (PI)} = \frac{\sum \text{PV (Revenue} - \text{O\&M} + \text{CCA Tax Shield)}}{\sum \text{PV of Capital Cost}} \text{ or PI} = \frac{\text{Benefits}}{\text{Cost}}$$

103. When the present value (PV) of revenues is greater or equal to the PV of project costs, the project PI will be greater or equal to 1.0 and makes the project economically feasible. A PI greater or equal to 1.0 means that the revenue

[28] PI formula is provided in The Guidelines for Assessing and Reporting on Natural Gas System Expansion in Ontario, EBO 188 (January 30, 1998).

recovers the entire cost of the project over its life and the project can be built at no cost to the customer. Depending on the size and scope of a project, Enbridge Gas may be required to submit an LTC application for OEB approval. In approving an LTC application, the OEB may require that Enbridge Gas meet certain conditions.

104. When the present value of revenues is less than the present value of costs, customers will be asked to pay a CIAC to recover the revenue shortfall. The CIAC is the amount of contribution required from the customer to make the project feasible (i.e., to achieve the required PI threshold).

105. In lieu of CIAC, the customer may be given an option to pay a System Expansion Surcharge (SES) or Temporary Connection Surcharge (TCS) to compensate for the revenue shortfall. The OEB-approved SES and TCS are volumetric charges[29] at $0.23/m^3. TCS and SES are charged on top of the normal distribution rates for a fixed term that is determined by feasibility calculations.

106. The amount charged as a lump sum CIAC or SES/TCS revenue paid over a certain term is project-specific and varies depending on the costs and revenues for each project. The OEB has established feasibility guidelines and rules for calculating the CIAC and TCS/SES terms. Utilities can only charge a CIAC or SES/TCS per methodologies approved by the OEB[30]. If the customer chooses not to pay, the project is not built.

[29] EB-2020-0094, Decision and Order, November 5, 2020.
[30] E.B.O. 188, The Guidelines for Assessing and Reporting on Natural Gas System Expansion in Ontario, January 30, 1998, and EB-2020-0094, Decision and Order, November 5, 2020.

Benefits

107. The project revenues are based on the monthly customer charges and delivery charges of the forecasted customers and are netted against ongoing incremental operating and maintenance costs of the project.

Costs

108. Direct capital costs for a project include materials (e.g., pipe, couplings, and meter sets, etc.), labour and equipment to install or construct the project, reinstatement of the surface (such as road, sidewalk, and landscaping), and the ongoing operation and maintenance of the project.

109. Indirect costs for a project may include the cost of the groups who support connecting new customers (e.g., Customer Connections) and the amortized cost of system reinforcement projects undertaken in the past.

Process for Connecting Residential Infill Customers

110. Residential infills are attached using the Extra Length Rule. This rule assumes that standard residential services are feasible to a certain threshold of length that is 20 metres and are attached at no cost to the customer. Any service beyond 20 metres is subject to an extra length charge at rates prescribed in Rider G of the Enbridge Gas Rate Handbook, provided at Exhibit 8, Tab 3, Schedule 1, Attachment 1. The length of the service will be measured from the customer's property line to the location where the gas meter is installed. The extra length criteria is as follows:

   a) Extra Length Charge: Beginning in the 2024 Test Year the extra length charge is proposed to be $159 per metre beyond the free service allowance /u
   of 20 metres. Further details on the update to this rate are provided at Exhibit 8, Tab 3, Schedule 1. The previous rates were $32 per metre in the EGD rate zone and $45 per metre in Union rate zones; and

b) Minimum Load: There is no minimum load required for residential infill customers to qualify for the free service allowance of 20 metres.

Customer Additions Forecast

111. The customer additions forecast is a projection of how many new customers will be attached to the distribution system over the next 10 years. Information considered in developing this forecast includes development projects originating from direct contact with builders, developers and municipalities as well as economic factors and indicators from reliable third-party data sources. These factors include housing starts forecasts, GDP growth, employment and mortgage rates. Enbridge Gas has been consistently using this approach, which was approved by the OEB in previous rate applications.

112. Further detail on the Customer Additions forecast is provided in Exhibit 2, Tab 6, Schedule 2, Section 5.1.4.

7.4 Projects Undertaken in Relation to Initiatives from the Minister of Energy

113. The communities in Ontario that remain without natural gas service are distant from existing gas distribution infrastructure, have relatively low numbers of potential consumers, and may have terrain that precipitates high construction costs. These factors have limited the ability of Ontario natural gas distributors to serve these communities, as economic feasibility requirements cannot be met.

114. In 2016, the OEB issued a decision in its generic proceeding on new community expansion[31] which indicated that incumbent utilities could propose an SES over and above existing rates to recover the shortfall in revenues to cover the cost of

[31] EB-2016-0004, OEB Decision and Order, November 17, 2016.

expansion and enhance the economic feasibility of community expansion projects. Community expansion projects, which employ an SES, are also subject to a 10-year rate stability period, during which the utility is to bear the risk of its customer attachment forecast and revenue requirement.

115. The Ontario government enacted policy to assist in the development of new infrastructure to allow for natural gas service to reach rural communities and rectify energy inequities for these communities.

116. In September 2018, the Ontario government passed Bill 32 designed to support a ratepayer-funded model to help finance projects designed to provide new communities with access to natural gas.

117. To determine which communities will be qualified for gas service expansions, the company assesses the economic feasibility for potential expansion projects within communities expressing interest in gas service expansion (using the same process used for the PI calculation). Many of these community expansion projects will still require the OEB's approval (where LTC approvals are required). Community expansion projects are categorized under the System Access category of projects. For further details on the large community expansion projects reflected in the forecast, please see Exhibit 2, Tab 6, Schedule 2, Section 5.1.9.3.

118. Enbridge Gas has several community expansion projects, completed or underway, made possible through phase one of the Natural Gas Expansion Program, which was announced in March 2019 with allocated funding of approximately $56 million. These projects include bringing natural gas to the communities of Chippewas of the Thames First Nation, North Bay-Northshore and Peninsula Roads, Saugeen First

Nation, Cornwall Island, Hiawatha First Nation, Scugog Island, and rural areas around Chatham-Kent.

119. Enbridge Gas brought natural gas to Fenelon Falls and Moraviantown First Nation, which was made possible with funding provided by the Ontario Government's previous Natural Gas Grant Program.

120. Enbridge Gas is committed to building on phase one successes by working with all levels of government to bring affordable, reliable natural gas to rural, northern and Indigenous communities across Ontario.

121. In December 2019, the Ontario Government announced it is continuing to expand access to safe, reliable, and affordable natural gas to rural, northern and Indigenous communities. As part of the announcement, the Ministry of Energy (MOE) sent a letter to every mayor in Ontario advising them of the Natural Gas Expansion Program.

122. Enbridge Gas submitted a number of project proposals to the OEB prior to the submission deadline of August 4, 2020. In total, Enbridge Gas submitted 203 Community Expansion project proposals and four Economic Development proposed projects.

123. The OEB evaluated these proposals and submitted its report to the MOE by October 31, 2020. The MOE reviewed the OEB's report and used it as an input to make project selections.

124. In June 2021, Ontario's Natural Gas Expansion Program allocated approximately $234 million in funding to support new natural gas expansion projects, this was a $104 million increase from the original $130 million funding amount.

125. Enbridge Gas is working to deliver the selected projects with varying construction start dates, with all starting by 2025. In Spring 2022, Enbridge Gas initiated construction on two of the selected projects: (1) Perth East (Brunner) and (2) Stanley's Old Maple Lane Farm (City of Ottawa: York's Corners Rd.). In addition, Enbridge Gas is working on a number of consultation efforts for upcoming projects.

E.B.O. 188

IN THE MATTER OF the Ontario Energy Board Act, R.S.O. 1990, c. O.13;

AND IN THE MATTER OF a hearing to inquire into, hear and determine certain matters relating to natural gas system expansion for The Consumers' Gas Company Ltd., Union Gas Limited and Centra Gas Ontario Inc.

BEFORE: G.A. Dominy
Presiding Member

R.M.R. Higgin
Member

J.B. Simon
Member

FINAL REPORT OF THE BOARD

January 30, 1998

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Appendix B: Guidelines for Assessing and Reporting on Natural Gas System Expansion in Ontario

1. THE PROCEEDING

1.1 THE BACKGROUND

1.1.1 In a Notice of Public Hearing dated July 31, 1995, the Ontario Energy Board ("the Board") made provision to hold a public hearing under subsection 13(5) of the Ontario Energy Board Act ("the OEB Act", “the Act”) to inquire into, hear and determine certain matters relating to the expansion of the natural gas systems of The Consumers' Gas Company Ltd. ("Consumers Gas"), Union Gas Limited ("Union") and Centra Gas Ontario Inc. (“Centra”), (collectively "the utilities"). The proceeding was given Board File No. E.B.O. 188.

1.1.2 In Procedural Order No. 1 the Board ordered the utilities to file their current policies for determining the feasibility of proposed system expansions and the application of environmental study reports.

1.1.3 The Board held an Issues Day meeting on September 11, 1995 and heard submissions on a proposed Issues List. The Board finalized the Issues List in Procedural Order No. 2 dated September 14, 1995.

1.1.4 Procedural Order No. 3, dated October 27, 1995, made provision for parties to file evidence and interrogatories on the evidence. The Order also provided for an alternative dispute resolution ("ADR") conference to be held commencing December 11, 1995 (“ the first ADR Conference”).

1.1.5 The Board received the *Report to The Ontario Energy Board on The Alternative Dispute Resolution Conference in E.B.O. 188 A Generic Hearing on Natural Gas System Expansion in Ontario*, on December 21, 1995 ("the first ADR Report"). There were divergent views expressed in the first ADR Report by the parties with respect to the principles involved in system expansion.

1.1.6 Having reviewed the first ADR Report, the Board issued Procedural Order No. 4 on January 11, 1996. In that Order, the Board directed that the parties choosing to file argument and reply should focus their submissions on the following issues:

> *1.1 Should financial feasibility be the only determinant for expansion or should it include, apart from security of supply and safety:*
>
> > *(1) an obligation to serve in areas where existing service is available;*
> > *(2) externalities;*
>
> *If externalities are to be included, what specific externalities, i.e. economic, social, environmental, should be considered? What tests should be applied and in what sequence?*
>
> *1.2 Given the answer to 1.1, what level of financial subsidy, if any, should be applied to system expansion;*
>
> *1.3 Should a portfolio of projects be utilized or should the utilities account for expansion on a project-by-project basis? How should the portfolio be defined?*

1.1.7 Submissions were filed on February 2, 1996 and reply submissions were filed on February 19, 1996.

1.1.8 An Interim Report of the Board ("Interim Report") was issued on August 15, 1996. In that Interim Report the Board made a determination of the issues and set out the principles that would apply to system expansion projects. The Board directed the parties to develop guidelines and policies reflecting the Board's conclusions. The Board also determined that the continuation of the proceeding should be by way of written submissions and a further ADR Settlement Conference ("the second ADR Settlement Conference").

1.1.9 A written common submission was filed by the utilities on September 30, 1996, and submissions and comments on the utilities' common submission were received from Board Staff, Consumers' Association of Canada, Canadian Industry Program for Energy Conservation, Industrial Gas Users Association/City of Kitchener, Green Energy Coalition, Northwestern Ontario Municipal Association/Federation of Northern Ontario Municipalities, Pollution Probe and Ontario Federation of Agriculture/Ontario Pipeline Landowners' Association.

1.1.10 In January 1997, the second ADR Settlement Conference was held. This resulted in the submission of:

- an ADR Agreement filed with the Board on March 14, 1997, subscribed to by the utilities and supported by a number of other parties ("ADR Agreement"), which included proposed System Expansion Guidelines;
- a dissent in the form of a document entitled "Deficiencies of the E.B.O. 188 ADR Agreement and their Rectification" dated April 1, 1997 ("Dissent Document");
- letters of comment from various parties on the ADR Agreement and Dissent Document; and
- responses (dated July 25, 1997) to a set of Board clarification questions to the utilities.

1.1.11 The parties concurring with the ADR Agreement and those substantially supporting the Dissent Document are listed in Appendix A.

1.1.12 In preparing this Final Report, the Board has considered the above documents. The resulting *Guidelines for Assessing and Reporting on Natural Gas Distribution System Expansion in Ontario (1998)* ("the Guidelines") are issued as Appendix B to this Report.

1.1.13 The following chapters set out the issues and the principles established in the Interim Report by quoting directly from that document. The positions of the parties are outlined by referencing the ADR Agreement, the Dissent Document and the various comments and clarifications made.

1.1.14 The Board’s comments and findings are structured as:

- The Portfolio Approach
- Common Methods for Financial Feasibility Analysis
- Customer Connection and Contribution Policies
- Environmental Planning Requirements for System Expansion
- Monitoring and Reporting Requirements

1.1.15 As of January 1, 1998, Union and Centra merged into a single company, Union Gas Limited. The Board’s findings in this Report and in the Guidelines are applicable to the new company and to Consumers Gas.

1.2 INTERVENTIONS

1.2.1 The following parties intervened in the proceeding:

- Canadian Association of Energy Service Companies
- City of Kitchener
- Consumers' Association of Canada
- Energy Probe
- Federation of Northern Ontario Municipalities
- Green Energy Coalition
- Grenville-Wood
- The Heating, Ventilation, Air Conditioning Contractors Coalition Inc.
- Industrial Gas Users Association
- Municipal Electric Association
- Natural Resource Gas Limited
- Northwestern Ontario Municipal Association
- Ontario Coalition Against Poverty
- Ontario Federation of Agriculture
- Ontario Hydro
- Ontario Native Alliance
- Ontario Pipeline Landowners' Association
- Ottawa-Carleton Gas Purchase Consortium

- Pollution Probe
- Power Workers' Union
- TransAlta Energy Corporation
- TransCanada PipeLines Limited
- Woodland Hills Community Inc.

Late Interventions

- The British Columbia Ministry of Energy, Mines and Petroleum Resources
- Canadian Industry Program for Energy Conservation
- Ecological Services For Planning Inc.
- F & V Energy Co-operative Inc.
- StampGas Inc.

2. THE PORTFOLIO APPROACH

2.1 INTERIM REPORT CONCLUSIONS

2.1.1 *The Board believes that utilities are in the best position to plan their distribution systems and, therefore, they should have flexibility in choosing the optimal system design for their distribution system expansions. The Board also believes that if the utilities are allowed to assess the financial viability of all potential customers as a group [using a portfolio approach] more marginal customers could be served as a result of assessing the cost of serving them together with more financially viable customers.*

2.1.2 *The Board is of the view that all distribution system expansion projects should be included in a utility's portfolio. This includes projects being developed for security of supply and system reinforcement reasons. The Board will be prepared on an exception basis to consider a utility's submissions as to why a proposed project should not be included in the portfolio but treated separately.*

2.1.3 *The Board believes that the issue of the timing of projects can be mitigated by the use of a rolling P.I. [Profitability Index] or benefit to cost ratio in the portfolio. The Board finds that using a rolling P.I. such as the approach used by Union will allow more opportunity for new projects to be added to the portfolio in a more timely fashion and that this is in the public interest. Union's rolling P.I. is a weighted average calculation of the cumulative net present value ("NPV") inflows divided by the cumulative NPV outflows during the preceding 12 months.*

2.1.4 *The Board expects the utilities to develop common policies on calculating rolling P.I.s. The forecast rolling P.I.s at a given point in time will be compared to the actuals in each utility's rates case to determine if any action needs to be taken with regard to forecast variances.*

2.1.5 *The Board recognizes that subsidization can be measured at both the project and portfolio level. An overall rolling portfolio P.I. 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 <u>or better</u> (emphasis added) is in the public interest. Using this approach will obviate the need for the intense scrutiny of the financial viability of each project; will ensure that existing ratepayers are not negatively impacted by new projects (given the Board's proviso above on the sharing of risks); and assist communities to obtain gas service where otherwise it would not be financially feasible on a stand-alone basis.*

2.1.6 *However, at the present time the utilities calculate the DCF ["discounted cash flow"] for proposed projects over long periods of time. The P.I. or benefit to cost ratio is based on this calculation. In the early years, the costs shown in the calculation generally exceed the revenues and there is a greater impact on rates than in the later years when revenues generally exceed costs. The Board is concerned that even if a utility demonstrates that its portfolio of distribution system projects shows a P.I. of at least 1.0 the impact on rates in a given year may be undue. For this reason, the Board expects the utilities to demonstrate in their rates cases that the short-term rate impact of the cumulative effect of the portfolios will not cause an undue burden on existing ratepayers.*

2.1.7 *The Board has considered whether or not it should impose a minimum threshold P.I. for projects to be included in the portfolios. The Board is concerned that the utilities may proceed with a number of projects with low P.I.s even though the P.I.s of the portfolios remain at 1.0 or greater. The cumulative impact of these projects may result in economic inefficiencies that outweigh the public benefit of the portfolio approach. From time to time, the Board will review the project specific data to monitor the operation of the portfolios in order to determine whether the cumulative* *economic inefficiency of proceeding with financially unfeasible projects outweighs the public interest in using the portfolio approach.*

2.2 POSITIONS OF THE PARTIES

2.2.1 The ADR Agreement proposed that each utility group all proposed new distribution customers and new facilities to serve them, for a particular test year into one portfolio (the "Investment Portfolio"). The Investment Portfolio would be designed to achieve a NPV of zero or greater (including normalized reinforcement costs).

2.2.2 The ADR Agreement proposed that each utility also maintain a rolling 12 month distribution expansion portfolio (the "Rolling Project Portfolio"). The cumulative result of project-specific discounted cash flow ("DCF") analyses from the past 12 months would be calculated monthly. The costs and revenues associated with serving customers on existing mains would not be included. The Rolling Project Portfolio would be used as a management tool by the utilities to decide on appropriate distribution capital expenditures.

2.2.3 The Dissent Document listed three concerns with the Investment Portfolio proposed in the ADR Agreement:

i. service lines off existing mains are included;
ii. security of supply projects are not included; and
iii. reinforcement costs have been normalized rather than using forecast actual costs.

2.3 BOARD'S COMMENTS AND FINDINGS

<u>Investment Portfolio</u>

2.3.1 The Board accepts the ADR Agreement proposal that each utility would group into one portfolio, the Investment Portfolio, all proposed new distribution customer attachments and facilities for a particular test year. The Investment Portfolio would be designed to achieve a positive NPV (greater than zero) in the test year (including normalized reinforcement costs).

2.3.2 The Board considers that a primary purpose of the Investment Portfolio analysis is to provide the Board with sufficient evidence to decide whether a utility's test year system expansion plan will result in undue rate impacts.

2.3.3 The Board understands that the ADR Agreement's proposed Investment Portfolio contains the capital costs of facilities for all new customers added during a test year. The analysis of system expansion financial feasibility includes revenues and operation and maintenance ("O&M") costs associated with these new customers over horizons as proposed up to 40 years. The utilities propose to include an allowance for reinforcement costs to supply the new projects on a normalized basis.

2.3.4 Since the Investment Portfolio analysis is intended to predict the financial and rate impacts of test year incremental system expansion capital expenditures and associated revenues and expenses, it is inappropriate to include historic capital expenditures or revenues from attachments in prior periods.

2.3.5 The Board accepts the difficulty in isolating test year customers attaching to new mains only (versus those attaching to mains built in prior years). However, as specified in the Guidelines attached as Appendix B, an estimate of the NPV without attachments to prior expansions will be required. This will enable the Board to better monitor the overall economic feasibility of such projects.

2.3.6 The Board's interpretation of the Investment Portfolio analysis and its associated rate impacts was assisted by reference to Consumers Gas' interrogatory response [Exhibit I, Tab 7, Schedule 8] in the E.B.R.O. 495 Consumers Gas 1998 rates case. The Board directs the utilities to file future impact analyses in a similar form (see paragraph 6.3.4).

2.3.7 The Board sought further explanation for the proposed treatment of reinforcement costs in the Investment Portfolio in its letter of July 4, 1997 to the utilities. The utilities responded that "normalized" reinforcement costs were categorized into "special" reinforcement and "normal" reinforcement. The costs of the former are those associated with specific major reinforcements of the system and are amortized over a period of 10-20 years. The normal reinforcement costs are the residual of the total identified reinforcement costs after the special reinforcement costs are deducted. The historical average for the special and normal reinforcement costs will then be used as the normalized amount to be included in the portfolio analysis as a percentage of the total capital expenditure in the year.

2.3.8 The Board finds the proposed treatment of reinforcement costs to be included in the Investment Portfolio as proposed in the ADR Agreement appropriate for overall portfolio analysis purposes. Union currently includes an allowance related to the carrying costs for advancement of reinforcement expenditures resulting from a new project and the Board finds this approach to be appropriate.

2.3.9 The Board does not agree that a design target of zero NPV and a P.I. of 1.0 is appropriate given the forecast risks inherent in the Investment Portfolio analysis. As the Investment Portfolio NPV approaches zero the marginal projects will be those with long cash flow break-even periods. Such projects require subsidy for long periods and hence increase short term rate impacts disproportionately.

2.3.10 In addition, the Board notes that the Investment Portfolio includes the costs and revenues associated with attaching customers to existing mains (i.e. mains constructed prior to any given test year). These projects by their nature will be more profitable for the utilities, since the costs of the mains are not included in the Investment Portfolio calculation. The Board concludes that the Investment Portfolio should be designed to achieve a positive NPV including a safety margin (for example, corresponding to a P.I. of 1.10). The Board believes that a portfolio designed in this way will minimize the forecast risks and hence more likely achieve the desired results of no undue rate impacts.

Rolling Project Portfolio

2.3.11 The Board also accepts the ADR Agreement proposal to maintain a Rolling Project Portfolio. The Rolling Project Portfolio provides an ongoing method of determining the financial feasibility and rate impact of expansion projects over a previous 12 month period. The Rolling Project Portfolio excludes the costs and revenues associated with new customers attaching to mains built prior to the last 12 month period. The Rolling Project Portfolio also provides a basis to compare a utility's Investment Portfolio with actual system expansion. Union has used a Rolling Project Portfolio approach for some time and has filed rate impacts from significant individual projects in its rates cases (e.g. E.B.R.O. 493/494 Exhibit B1, Tab 4, Appendices C and D).

2.3.12 As noted above the Board finds the proposed treatment for reinforcement costs to be included in the Rolling Project Portfolio to be appropriate.

2.3.13 The Board finds the Rolling Project Portfolio as proposed by the utilities to be a useful management tool. This Portfolio provides a mechanism for facilitating review of the financial status of overall distribution system expansion at the time that individual major projects are before the Board for either franchise and certificate approval, or for approval of leave to construct and also for monitoring purposes.

2.3.14 The Board has previously expressed its position that inclusion in the Investment Portfolio, of revenues and costs for infill customers connecting to existing mains may provide a mismatch between periodic costs and revenue. The Board notes that the Rolling Project Portfolio, which is the utilities' primary management tool, does not include such infill customers. Therefore, the Board finds that the Rolling Project Portfolio does provide appropriate matching and that an NPV of zero (or greater) is appropriate.

3. COMMON METHODS FOR FINANCIAL FEASIBILITY ANALYSIS

3.1 INTERIM REPORT CONCLUSIONS

3.1.1 *The Board believes that a further review of the methodology to be used by the utilities in assessing the project and portfolio financial feasibility is necessary. Among the factors to be considered are the period for new attachments and the time period over which the DCF analysis is calculated. The Board expects utilities to develop common methods for the Stage I Financial Feasibility test that will be used to show whether or not each utility's portfolio of distribution system expansion projects is profitable.*

3.2 POSITIONS OF THE PARTIES

3.2.1 The ADR Agreement set the following parameters for the DCF analysis:

(a) Customer Attachment Horizon

A maximum 10 year forecast horizon will be utilized. For customer attachment periods of greater than 10 years an explanation of the extension of the period will be provided to the Board.

(b) Customer Revenue Horizon

The maximum customer revenue horizon shall be 40 years from the in-service date of the initial mains, except for large volume customers where the maximum shall be 20 years from the customers' initial service.

(c) Discount Rate

The Utilities' incremental after-tax cost of capital will be used for the discount rate. This will be based on the prospective capital mix, debt and preference share costs, and the latest Board approved equity return levels.

(d) Discounting

Discounting will reflect 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 related costs, and operating and maintenance expenditures.

(e) Operating and Maintenance Expenditures

The incremental costs directly associated with the attachment of new customers to the system will be included in the operating and maintenance expenditures.

(f) Gas Costs

In the near term, the weighted average cost of gas ("WACOG") will continue to be the proxy for gas costs (gas costs shall be WACOG less the commodity portion of the gas costs). This approach may not be appropriate in the case of projects for large customers, where a specific gas cost forecast may be required.

3.2.2 The parties to the Dissent Document submitted the ADR Agreement was deficient in that the utilities had not agreed on a common method for calculating their P.I.s; that a 40 year revenue horizon may result in existing customers paying undue rate increases; and that 40 years is inappropriate in the absence of shareholder responsibility for forecast variations.

3.2.3 The Dissent Document also stated that the utilities were understating the costs in the financial feasibility analysis, since they are not using incremental costs for gas storage and transportation services, but have proposed that gas costs be WACOG less the commodity portion of gas costs.

3.2.4 The Dissent Document proposed:

- a customer attachment horizon no longer than 5 years (unless there is a specific contract);
- a maximum time period for the DCF calculation of 20 years from the in-service date of the initial main for large volume customers and between 20 and 30 years for small volume customers;
- customer use volumes representing the best estimates of the gas consumption for new customers; and
- the inclusion of incremental costs associated with gas storage and TransCanada PipeLines Limited transmission.

3.3 BOARD'S COMMENTS AND FINDINGS

3.3.1 The Board notes that the utilities have undertaken to apply consistent business principles for the development of the elements of the financial feasibility test. These elements include: customer attachment horizon, customer revenue horizon, discount rate and timing, operating and maintenance expenditures, and weighted average gas costs.

3.3.2 The Board notes that the proposed customer attachment forecast horizon of 10 years is a maximum and adopts this as part of the Guidelines in Appendix B.

3.3.3 The Board is concerned that a customer revenue horizon of 40 years will encourage inclusion of projects with very long cash flow break-even periods and hence high levels of subsidy in the early years. The Board has addressed this issue as part of the design targets for the Investment Portfolio.

3.3.4 The Board concludes that, although theoretically correct, the inclusion of forecast incremental costs for the transportation and storage of gas will add unnecessary complexity to the DCF calculations for distribution system expansion projects.

3.3.5 The Board finds however that the methodology should include a standard test or measure to assess short term rate impacts at the Portfolio level. This would be similar to the Rate Impact Measure ("RIM") Test used to evaluate Demand Side Management ("DSM") programs, with the objective of allowing comparisons from year to year and, to a degree, among the separate portfolios of the utilities.

3.3.6 The Board accepts that the DCF calculation will be based on a set of common elements as proposed in the ADR Agreement. These common elements will be reflected in the DCF analysis for the Investment Portfolio and the Rolling Project Portfolio filed by each of the utilities in its rates cases, the details of which are set out in Appendix B.

4. CUSTOMER CONNECTION AND CONTRIBUTION POLICIES

4.1 INTERIM REPORT CONCLUSIONS

4.1.1 *In the last few years, the Board has approved contributions in aid of construction in the form of periodic contribution charges for residential and small commercial customers in order to improve the profitability of projects when the P.I. or benefit to cost ratio is less than 1.0.*

4.1.2 *The Board notes that accidents of timing and geography can ... lead to inequitable situations where some ratepayers in similar situations may not have to pay a contribution while others are required to pay contributions.*

4.1.3 *The Board realizes that customers have indicated their willingness to contribute towards the cost of projects that are not financially feasible in order to obtain gas service. The Board also notes that there may be communities that would be so costly to serve and the P.I. so low that they are unlikely ever to be included in the portfolio. The Board accepts that in these special circumstances a contribution in aid of construction from a community would be acceptable on a case by case basis, but the Board will not expect the utilities to require contributions from all projects which do not meet a threshold P.I. of 1.0. In light of these considerations, the Board expects the utilities to prepare common guidelines on the treatment of customers currently paying periodic contribution charges.*

4.1.4 *The Board will review in the next phase of this proceeding the utilities' policies on requiring contributions in aid of construction where dedicated facilities are being constructed primarily for a single customer. In this regard the Board is interested in a policy that deals with all customer classes and expects the utilities to prepare a policy that is common among the utilities.*

4.2 POSITIONS OF THE PARTIES

4.2.1 The ADR Agreement states that the utilities will accept contributions in aid of construction for communities or projects that would otherwise not likely be included in the portfolio.

4.2.2 The ADR Agreement also proposed that existing contractual arrangements for the collection of contributions continue with the exception of Consumers Gas' projects for which contributions would be adjusted to achieve a P.I. of 0.8.

4.2.3 The ADR Agreement did not propose a definition to be used in determining when a facility is to be considered "dedicated".

4.2.4 The Dissent Document does not address the issue of customer contribution policies.

4.3 BOARD'S COMMENTS AND FINDINGS

4.3.1 The Board notes that the utilities wish to retain the ability to accept contributions in aid of construction for communities or projects that would not otherwise be included in the portfolio. However, no cost limits or P.I. thresholds have been recommended by the parties to assist the utilities in making such decisions. As stated in the Interim Report, the Board believes that the utilities should continue to make decisions on contributions in an even handed manner.

4.3.2 The Board recognizes that Union and Centra have been applying a P.I. threshold of 0.8 for the collection of customer contributions for new community attachments. The Board also notes that the utilities proposed this level as the basis for determining the treatment of customers currently paying periodic contributions. In order to ensure fairness and equity in the application and design of contribution requirements, the Board finds that all projects must achieve a minimum threshold P.I. of 0.8 for inclusion in a utility's Rolling Project Portfolio.

4.3.3 The Board directs the utilities to prepare and maintain a common set of Board-approved customer connection policies that shall, as a minimum, include:

i. the circumstances under which customers will be required to pay for all, or part, of their service line connection, including the specific criteria and the quantum of, or formula for calculating, the total or excess service line fees and other charges; and

ii. the circumstances where the use of a proposed facility will be dominated by one or more large volume customers for which the utilities will retain the option of collecting contributions in aid of construction. The contribution amounts will be consistent with the cost allocation for such mains and accordingly based on the peak day demand and the cost allocators used by each of the utilities.

4.3.4 The Board agrees with the parties that the common criteria for contributions in aid of construction should apply to all customer classes. If there is a reasonable expectation of further expansion, the contribution in aid of construction is expected to take into account the future load growth potential and timing of any such expansion.

4.3.5 The Board expects the utilities to bring forward common proposals for customer connection and contribution policies for Board approval. These proposals will be reviewed in each of the utilities' rate cases.

5. ENVIRONMENTAL PLANNING REQUIREMENTS FOR SYSTEM EXPANSION

5.1 INTERIM REPORT CONCLUSIONS

5.1.1 *The Board requires that for all distribution projects, the utilities prepare a display of alternatives (routes and sites) which would show the various trade-offs between customer attachments and environmental, social and financial costs. The Board expects the utilities to prepare common guidelines on how to conduct and document the evaluation of their route selection and to apply these to all expansion projects.*

5.1.2 *The Board also expects the utilities to appropriately apply the [Board's] Environmental Guidelines for Locating, Constructing and Operating Hydrocarbon Pipelines in the Province of Ontario, Fourth Edition, 1995 ("the Environmental Guidelines") to all distribution system projects whether or not they involve a facilities application to the Board. The Board believes that the type and level of detail of the environmental investigations conducted by the utilities should be determined on the basis of environmental significance, and not on whether or not a particular application comes before the Board, whether a proposed pipeline is a distribution or transmission line, or whether or not the line will be located in a town. The utilities should conduct and document the necessary investigation and develop mitigation measures where significant environmental features are encountered. It is expected that the utilities will not require additional resources to undertake these investigations.*

5.1.3 *The utilities will have to confirm in their rates cases that all proposed projects meet the guidelines on route selection and the Environmental Guidelines and if not, why not. In addition, for facilities applications, the Board expects the utilities to file the project specific route selection display and environmental report. The Board expects that the utilities may incorporate the route selection evaluation into their environmental report.*

5.1.4 *The requirements to conduct and document the evaluation of the route selection and to apply the Environmental Guidelines to all distribution projects will be incorporated in the Environmental Guidelines.*

5.1.5 *In facilities applications the utilities will also have to continue to satisfy the Board on the design and construction practices and costs for the project. In addition, the Board will have to be satisfied that landowner concerns have been met and that any necessary permits have been obtained.*

5.2 POSITIONS OF THE PARTIES

5.2.1 The ADR Agreement proposed that whenever a need for gas is identified, and a reasonable source is available, an evaluation would be done on whether this need could be accommodated. Full information on service alternatives would be gathered, including potential customers served, the running line location, construction costs and environmental and socio-economic concerns.

5.2.2 In selecting a preferred route, the ADR Agreement stated that standard environmental guidelines will be used for dealing with most environmental features. Significant environmental features (those not covered by the utilities' standard environmental guidelines) will require separate evaluation and may require public meetings and agency consultation.

5.2.3 The ADR Agreement proposed that costs of avoiding significant environmental features or mitigating significant environmental impacts will be included in the cost and benefit analysis for the project. For projects with similar economic benefits, routes that avoid significant environmental features will be preferred. Generally, routes with the greatest economic benefits overall will be preferred, subject to the environmental considerations described above.

5.2.4 The parties to the Dissent Document submitted that the ADR Agreement is not consistent with the Board's Interim Report because:

i. the utilities have not yet developed common guidelines on how to conduct and document the evaluation of their route selection; and

ii. according to the ADR Agreement, the utilities can select a route that will cause significant harm to the local environment if the route's economic benefits exceed its costs to the environment.

5.2.5 The parties to the Dissent Document proposed that the utilities be required to prepare and apply common guidelines on how to conduct and document the evaluation of their route selections to all expansion projects.

5.2.6 Energy Probe, the Green Energy Coalition, and Pollution Probe proposed that the utilities should be required to adopt as a principle that there should be "no net loss" of local environmental resources as a result of their system expansion activities. Where a utility is unable to offset the environmental impacts of its system expansion activities, the utility should make best efforts to create an offsetting environmental resource to meet the "no net loss" principle.

5.3 BOARD'S COMMENTS AND FINDINGS

5.3.1 The Board notes that a move to a portfolio planning and management approach may result in less public scrutiny of the financial and economic evaluation of individual system expansion projects. However this does not imply that there should be any decrease in the necessary level of environmental assessment of projects by the utilities, or the documentation of this work, as these matters will continue to be reviewed by the Board.

5.3.2 The planning principles described in the Board's Environmental Guidelines shall also apply to distribution expansion projects undertaken by the utilities. The level of detail required, the degree of public consultation and the level of alternative route/site evaluation should be determined by the utilities in a manner consistent with the Environmental Guidelines based on a review of the environmental (biophysical and socio-economic) significance of features potentially impacted by a proposed project. Environmental significance is to be determined based on the expected impacts of a particular project, not on whether the feature is covered by the utility's environmental guidelines.

5.3.3 To assist in determining what level of planning, investigation and reporting is necessary, the Board finds that the utilities shall jointly develop a common set of environmental screening criteria to determine if significant environmental features may be impacted during the construction or the operation of the facility. Corresponding planning, documentation, and reporting requirements are to be jointly developed and applied by each utility depending on the impacts expected as determined through the screening process. The criteria and corresponding requirements can be in the form of a checklist. The Board will review the screening criteria and the corresponding planning, documentation and reporting requirements for inclusion in the Environmental Guidelines. The Board expects the utilities to submit this material to the Board by June 1, 1998.

5.3.4 Once the study area for the project is determined, a regional officer of the utility who is familiar with the study area and has been trained in environmental matters shall identify potential impacts through the screening process and determine the level of planning required. Depending on the significance of the potential impacts anticipated, the decision on the level of planning may involve additional environmental specialists of the utility, external consultants and other affected parties.

5.3.5 Depending on the level of significance of the environmental feature(s) encountered, the planning may involve alternative routing/siting considerations, detailed mitigation requirements and/or public and/or agency review. It is expected that the criteria and requirements will be updated from time to time by the utilities in consultation with other interested parties and reviewed by the Board for inclusion in updated Board Environmental Guidelines.

5.3.6 Where alternative routes or sites are investigated, the Board expects that the preferred alternative will be chosen based on an optimization of the particular environmental, social and financial criteria for the project. Decisions on the relative importance of these criteria are to be made based on the specific environmental features encountered and their significance, rather than deciding in advance that financial criteria have priority.

5.3.7 In those cases where the significance of environmental features may be in question or the planning requirements are not clear, the utilities are expected to consult with environmental specialists, Board Staff and affected parties. The Board expects that as experience is gained, consultation will be necessary only in unusual cases. In all cases however, it is expected that provincial and local agency requirements (permits, licences) shall be obtained where necessary and that the utilities will apply their standard guidelines, drawings, and specifications.

5.3.8 The Board finds that further examination of the "no net loss" principle is unnecessary in this proceeding in light of the Board's specified environmental planning requirements.

6. MONITORING AND REPORTING REQUIREMENTS

6.1 INTERIM REPORT CONCLUSIONS

6.1.1 *The Board also expects the utilities to develop proposals on the appropriate method to use to monitor the variation between forecast and actual profitability of their distribution system expansion portfolios.*

6.1.2 *Despite the advantages of a portfolio approach, the Board is of the view that certain containment practices should be put in place in order to ensure that:*

- *ratepayers are protected from financially risky decisions on expansion by the utilities;*
- *the utilities make decisions on which projects should proceed in an even-handed manner;*
- *the cumulative impact on rates is not undue in any given year;*
- *the continued expansion of natural gas service is in the overall public interest; and*
- *the economic inefficiencies implicit in including projects with negative P.I.s do not outweigh the public interest benefits of the portfolio approach.*

6.1.3 *Utility shareholders will be held responsible for any significant variation in the forecast of customer attachments, volumes and costs from the aggregate portfolio. The Board expects the utilities to make proposals in the next phase of this proceeding on how variances from the aggregate forecast should be treated in order to* *appropriately share the risk between ratepayers and shareholders. In considering how the risk should be shared, the utilities may want to review their policies on obtaining financial assurances from new large volume customers.*

6.1.4 *The Board also expects the utilities to develop proposals on the appropriate method to use to monitor the variation between forecast and actual profitability of their distribution system expansion portfolios.*

6.1.5 *However, the Board finds that it is in the public interest to require the utilities to demonstrate that it continues to be in the overall public interest to expand the natural gas distribution systems from an aggregate economic, social and environmental point of view. Therefore, the Board will require utilities to file the results of a societal cost test ["SCT"] of their overall portfolios of distribution system expansion when seeking approval of their portfolios. The societal cost test could include monetized, non-monetized and qualitative components. To this end, the Board requests the utilities to develop a common evaluation method, that would be cost-effective, that would adequately characterize performance, and that would be relatively straightforward to apply.*

6.1.6 *The Board expects the utilities to develop common reporting requirements so that the utilities' forecast P.I.s, customer attachments, volumes and costs can be compared to actuals on a portfolio basis and, if need be, on a project specific basis. This information shall be put on the record in the rates cases to serve as a benchmark.*

6.1.7 *The Board expects that under the portfolio approach the Stage I financial feasibility P.I. will be calculated for each proposed project as well as for the portfolio of infill projects. For the purposes of calculating the P.I. of the infill portfolio, infill projects are defined as the extension of mains and service attachments in existing service areas, but does not include service lines to individual customers off existing mains.*

6.1.8 *All the P.I.s of the proposed projects and the infill portfolio will be aggregated to calculate the overall portfolio P.I. at a given time for each utility.*

6.2 POSITIONS OF THE PARTIES

6.2.1 The ADR Agreement proposed that the utilities file Test Year and Historic Year information as part of their rates cases. This information would include the capital amounts, profitability and rate impacts of the Investment Portfolio and the Rolling Project Portfolio; actual expenditures on reinforcement costs; and specific customer attachment information on a set of randomly selected projects.

6.2.2 The ADR Agreement also proposed that each utility file in its rate case a projected NPV of the results of a SCT for the Investment Portfolio for the test year. The results would be presented both with and without monetized externality costs and benefits.

6.2.3 The parties to the Dissent Document submitted that the ADR Agreement fails to meet the Board's direction in the Interim Decision because:

- the ADR Agreement does not require the utilities to report the P.I.s of their Investment Portfolios or any individual project within their Investment Portfolios;

- the ADR Agreement does not require the utilities to report the forecast aggregate NPV and P.I. of the test year's projects that have negative P.I.s (information necessary to address the Board's concern with respect to economic efficiency); and

- the ADR Agreement does not require the utilities to put on the record in their rates cases project specific P.I.s, customer attachments, volumes and cost data so that project specific information can serve as a benchmark for monitoring performance on an on-going basis.

6.2.4 The parties to the Dissent Document further submitted that the ADR Agreement fell short because:

- there is no commitment to provide a comparison of actual and forecast volumes;

! there is no commitment to provide a comparison of actual and forecast capital expenditures for the Investment Portfolio; and

! the utilities are only committed to providing a comparison of their actual and forecast customer attachments for the first three years of a project's life, which does not cover the remaining 7 years in a project's 10 year customer attachment forecast period.

The parties to the Dissent Document proposed that the utilities should be required to file portfolio and project specific information for the historic, bridge and test years.

6.3 BOARD'S COMMENTS AND FINDINGS

6.3.1 The Board believes that the principles outlined in the Interim Report should form the basis of the monitoring and reporting requirements.

Rate Case Review

6.3.2 The Board directs that the utilities file, in their respective rates cases, a forecast NPV and P.I. of the test year Investment Portfolio. In subsequent rates cases, each utility will report to the Board on the actual results of the Investment Portfolio.

6.3.3 The actual results of the Investment Portfolio will present the NPV and the P.I. taking into account the capital spent, the number of customers attached and the revenues received from the customers attached in the most recent historical year for which there is full data. Volume usage for larger commercial and industrial customers will be individually estimated to more closely reflect actual annual volumes.

6.3.4 Each utility will, in its rates case, provide an analysis of the estimated rate impact of its Investment Portfolio in the first five years of service. As referred to earlier, the Board found the material filed by Consumers Gas in E.B.R.O. 495 at Exhibit I, Tab 7, Schedule 8, to be a good example of the information necessary, but would be further assisted if the impacts were broken down by rate class. The Board directs that such a breakdown be included in the required impact analysis.

6.3.5 As noted earlier, the Board also wishes the utilities to use a standard rate impact test or measure similar to the R.I.M. test used to assess DSM program impacts. This measure should present the following information in aggregate and by rate class:

- impact of the Investment Portfolio cash flow on the test year revenue deficiency; and
- the ratio of incremental revenues to costs in the test year and subsequent three years.

6.3.6 The Board notes that in recent rates cases both Centra and Consumers Gas have significantly overspent their Board-approved capital budgets, particularly in the bridge year. In its E.B.R.O. 493/494 Decision the Board set out the criteria of *affordability* and *rate stability* as key factors affecting the capital budget and additions to rate base, which the Board will consider in assessing prudence of expenditures.

6.3.7 The Board notes that the addition of capital for assets such as Information Technology and Customer Information Systems may have significant impacts on both the level of capital expenditure and year to year additions to rate base. The Board in its E.B.R.O. 493/494 Decision suggested that affordability criteria be applied to develop ceilings for capital expenditures and rate stability criteria be used to manage the scheduling of expenditures on more discretionary projects in conjunction with system expansion projects. In addition, in E.B.R.O. 495 the Board expressed its concern about the upward pressure on rates resulting from continual system expansion, and concluded that, for ratemaking purposes, expenditures above overall Board-approved levels in various categories (“envelopes”) of the capital budget could not automatically be included in the Company’s proposed rate base for the next fiscal year. In addition, the Board cautioned that the Company would be required to prove the reasonableness of its capital expenditures within each envelope, even if the expenditures were at or below the Board approved level.

6.3.8 The Board expects that the concerns raised in these recent rate cases regarding affordability and rate stability will be addressed in the utilities’ plans under the portfolio approach.

6.3.9 The Board will treat variances between actual and forecast portfolio NPVs in the same manner as for other forecast test year variables. The utilities will provide explanations of the reasons for the variations and the corrective actions taken or proposed. The Board will judge the degree to which the cost impacts should be apportioned between the shareholder and the ratepayers.

6.3.10 The Board agrees with the ADR proposal for portfolio level SCT analysis, monitoring and reporting, using a test that is consistent with the treatment of the SCT for DSM.

Ongoing Monitoring and Reporting

6.3.11 The Board notes that the primary purposes of the Guidelines in Appendix B are to streamline the process of approval of system expansion projects and achieve a commonality of approach between the utilities, while ensuring that ratepayers are protected against the impacts of either over-aggressive, or financially inappropriate, system expansion by the utilities.

6.3.12 The Board believes that the achievement of these objectives requires periodic standardized reporting to the Board, as well as the filing of information in rate cases in order to allow the prudence of the utilities' actions and rate impacts to be reviewed. These reviews should appropriately be rate focussed with account taken of both short-term and long-term costs and benefits to ratepayers.

6.3.13 The Board considers that, in general, the ADR Agreement proposals in the section *Monitoring the Performance of the Portfolios/Short Term Rate Impacts*, provide a reasonable point of departure and that experience should show whether the content and timing of the monitoring and reporting requirements are adequate. The Board will require filing of the P.I.s of the portfolios as well as the NPVs. The adjusted monitoring requirements are included in the Guidelines in Appendix B.

6.3.14 The Board emphasizes that the utilities must maintain clear records at a project specific level that will allow for inspection and/or reporting of individual projects as may be deemed necessary from time to time.

6.3.15 The Board will require quarterly filing of the monthly reports on the Rolling Project Portfolio and total capital expenditures in order to monitor performance.

6.3.16 The approach to environmental planning outlined above should simplify the documentation requirements. The sampling process and reporting required in the Guidelines will ensure consistency across projects and between utilities and ensure compliance with the Board's environmental planning requirements.

7. COMPLETION OF THE PROCEEDING AND COSTS

7.1 COMPLETION OF THE PROCEEDING

7.1.1 The Board has reviewed the letters of comment setting out the positions of various parties on the ADR Agreement and the Dissent Document. The Board is of the view that it would not be in the public interest at this stage to hold additional hearings on this matter. Rather, the Board believes that the public interest is better served by proceeding with the implementation of the Guidelines included in Appendix B of this Report.

7.1.2 The Board directs that the Guidelines shall be implemented as soon as possible, but no later than the 1999 fiscal year for each of the utilities. The Guidelines will be subject to future review by the Board in the light of experience gained in their application.

7.2 COSTS

7.2.1 In the Board's Interim Decision of August 15, 1996 the parties to the proceeding were directed to submit cost claims for that phase of the proceeding. The Board made an interim cost award to those parties requesting one.

7.2.2 The Board directs all parties who wish to do so, to submit their final claim for costs with the Board and a copy to each of the utilities, taking into account the interim cost award (if applicable) by February 20, 1998. Comments from the utilities are to be filed by March 2, 1998 and reply by parties by March 16, 1998. The Board will issue its Cost Award Decision and Order in this proceeding in due course.

7.2.3 The Board directs the utilities to pay the Board's costs of, and incidental to the proceeding upon receipt of the Board's invoice.

7.2.4 The Board directs that all costs be apportioned on a 50:50 basis between Consumers Gas and Union/Centra Gas.

DATED AT TORONTO January 30, 1998.

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G.A. Dominy
Vice Chair and Presiding Member

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R.M.R. Higgin
Member

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J. B. Simon
Member

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APPENDIXB ONTARIO ENERGY BOARD GUIDELINES FOR ASSESSING AND REPORTING ON NATURAL GAS SYSTEM EXPANSION IN ONTARIO

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CONTENTS

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I. OVERVIEW - PURPOSE AND OBJECTIVE OF THE GUIDELINES

The Ontario Energy Board ("OEB", "Board") <u>Guidelines for Assessing and Reporting on Natural Gas System Expansion In Ontario</u> ("The Guidelines") provide a common analysis and reporting framework to be applied by regulated Ontario Local Distribution Companies - Union Gas Limited and The Consumers' Gas Company Ltd. ("the utilities") to natural gas distribution system expansion. The principles upon which the Guidelines are based reflect the Board's conclusions in its Distribution System Expansion Reports under Board File No. E.B.O. 188. (Interim Report[12JM1-0:1] dated August 15, 1996; Final Report[1] dated January 30, 1998). 259

Portfolio Approach 260

The main change from prior policy and practice is the use of a portfolio approach, as opposed to a 261 project-by-project approach, to the planning, analysis, management and reporting of distribution system expansion projects. The intent of the portfolio approach is to provide the utilities a greater degree of flexibility in determining which projects to undertake, while the Board retains overall regulatory control to ensure no undue cross subsidy or rate impacts result from distribution system expansion.

Financial Feasibility Analyses 262

The Guidelines provide the utilities with direction with respect to the structure of their system 263 expansion portfolios and the methods for conducting financial feasibility analyses at both the individual project level and the portfolio level. The Guidelines standardize the elements to be used in the discounted cash flow ("DCF") analysis as well as establish the parameters for the costs and revenues that are the inputs to that analysis.

Reporting 264

The Guidelines establish a mechanism to evaluate the performance of each of the utilities' distri- 265 bution expansion activities on a portfolio basis and on an individual project basis. The Guidelines also outline reporting requirements for system expansion plans and post expansion impacts. The forecast rate impacts of a utility's expansion plans will be presented in rates case filings on a prospective test year basis.

These reporting requirements are intended to provide the Board and interested parties with suffi- 266 cient information to monitor the utilities' expansion activities and their associated rate impacts. The performance of the utilities related to implementation of these Guidelines will be evaluated as part of each utility's rates case.

Customer Connection Policies Was Appendix, page 2 267

Part of the utilities' management of distribution system expansion will be the provision of common 268 customer connection policies. These will include policies relating to service line fees, customer contributions to otherwise financially unfeasible projects and for projects dominated by one or more large volume customers.

Environmental Considerations 269

To ensure that the utilities plan and construct system expansion facilities in an environmentally 270 acceptable manner, the Guidelines also address the routing and environmental planning, documentation and reporting requirements for distribution expansion projects.

1. SYSTEM EXPANSION PORTFOLIOS Was Appendix, page 3 271

1.1 Investment Portfolio 272

Each of the utilities will group into a portfolio (the "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. 273

The Investment Portfolio will be designed to achieve a profitability index ("PI") *greater* than 1.0. 274

1.2 Rolling Project Portfolio 275

Each of the utilities will maintain a rolling 12 month distribution expansion portfolio (the "Rolling Project Portfolio") updated monthly, as an ongoing management tool for estimation of the future impacts of capital expenditures associated with distribution system expansion. The Rolling Project Portfolio will exclude those customers requiring only a service lateral from an existing main. 276

The utilities will calculate monthly the cumulative result of project-specific DCF analyses from the past twelve months for the Rolling Project Portfolio. It will include all future customer attachments, revenues and costs on the basis of the life cycle of each of the projects making up the Portfolio. 277

2. STANDARD TEST FOR FINANCIAL FEASIBILITY 278

The standard test for determining the financial feasibility at both the project and the portfolio level will be a DCF analysis, as set out below. 279

2.1 DCF Calculation and Common Elements 280

The DCF calculation for a Portfolio will be based on a set of common elements. For <u>revenue forecasting</u>, the common elements will be as follows: 281

(a) for the Rolling Project Portfolio, total forecasted customer attachments over the Customer Attachment Horizon for each project; 282

(b) for the Investment Portfolio, a forecast of all customers to be added in the Test Year; 283

(c) an estimate of average use per added customer which reflects the mix of customers to be added; 284

(d) a factor which reflects the timing of forecasted customer additions; and 285

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(e) rates derived from the existing rate schedules for the particular utility, net of the gas commodity component. 286

For capital costs, the common elements will be as follows: 287

(a) 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; 288

(b) an estimate of incremental overheads applicable to distribution expansion at the portfolio level; and 289

(c) an estimate of the normalized system reinforcement costs. 290

For expense forecasting, the common elements will be as follows: 291

(a) gas costs as used in revenue forecasts (excluding commodity costs); 292

(b) incremental operating and maintenance costs; 293

(c) income and capital taxes based on tax rates underpinning the existing rate schedules; and 294

(d) municipal property taxes based on projected levels. 295

2.2 Specific Parameters 296

Specific parameters of the common elements include the following: 297

(a) a 10 year customer attachment horizon;. 298

(b) a customer revenue horizon of 40 years from the in service date of the initial mains (20 years for large volume customers); 299

(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; 300

(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 301

(e) gas costs based on the weighted average cost of gas ("WACOG") excluding commodity costs. 302

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3. MONITORING PORTFOLIO PERFORMANCE AND SHORT-TERM RATE IMPACTS 303

3.1 Rates Case Filings 304

The following information will be filed in each rates case: 305

Test Year 306

(a) the Investment Portfolio, including NPV, the total capital in the portfolio and the portfolio PI; 307

(b) an estimate of the aggregate NPV of all new facilities requiring a new franchise and/or certificate of public convenience and necessity and of all "infills" (i.e. main extensions and service attachments in existing service areas excluding service lines to customers off existing mains) based on extrapolated historical data; 308

(c) an estimate of the Test Year rate impacts of the Investment Portfolio based on the: 309

(i) contribution to annual revenue requirement; 310

(ii) Rate Impact Measure presented as the ratio of added revenue to costs for each customer class; and 311

(iii) class-specific estimated percent rate and annual average bill increases. 312

(d) estimates of the NPV and the benefit-cost ratio for the Investment Portfolio using a Societal Cost Test ("SCT"), defined in the Report of the Board, E.B.O. 169 III, as an evaluation of the costs and/or benefits accruing to society as a whole, due to an activity. The SCT analysis should be consistent with that used for the utilities' DSM programs. The benefit-cost ratio shall be presented with and without monetized externalities. 313

<u>Historic Year:</u> 314

(a) the Historic Year Investment Portfolio, including the NPV, total capital in the portfolio, and the portfolio PI; 315

(b) the aggregate NPV, the total capital, and the portfolio PI for: 316

- (i) the Rolling Project Portfolio at the end of the historic year; 317
- (ii) all completed projects with negative NPVs; 318
- (iii) all completed projects with positive NPVs; 319

(c) upon the request of the Board, a list of the projected results of individual extensions included in the Rolling Project Portfolio; 320

(d) actual expenditures on reinforcement projects; and 321

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(e) the rate impact of the Historic Year Investment Portfolio reflecting actual capital expenditures and customer related data. 322

3.2 Ongoing Monitoring Information 323

The utilities shall establish a process to allow the Board to monitor the performance of their distribution system expansion project portfolios including financial and environmental requirements. 324

A. <u>Financial Monitoring</u> 325

In consultation with Board Staff, the utilities shall select projects from their Rolling Project Portfolios on an annual basis and shall file the following with respect to the sample: 326

- (a) the cumulative number of customers attached at the end of the 3rd full year and the associated revenues and costs; and 327
- (b) the corresponding year 3 customer attachment forecasts and associated revenues and costs. 328

B. Environmental Monitoring 329

In consultation with Board Staff, the utilities shall select a set of completed projects and file data on those projects on an annual basis as described below. The projects chosen should be selected in a random, stratified manner, reflecting the range of environmental impacts encountered in the time period and the various levels of environmental planning, documentation and reporting required. The selection should be reviewed by an independent auditing group within the utility, which group shall include (a) trained environmental auditor(s). The utility shall file the following with respect to each sample: 330

1. a description of how the project complied with the Board-approved environmental screening, planning, documentation and reporting requirements; 331

2. a table of significant features, how they were avoided or mitigated, and resulting impacts; 332

3. a table displaying the concerns raised by affected parties including member ministries of the Ontario Pipeline Coordination Committee, how they were addressed, and reasons for any outstanding concerns; 333

4. issues of significance arising from any post-construction monitoring; 334

5. where alternatives were investigated, a display of alternatives (routes/sites) which show the various trade-offs between customer attachments, and environmental, social and financial costs and a discussion of how the preferred alternative was chosen; 335

6. evidence that all necessary approvals (permits, licences) were obtained; and Was Appendix, page 7 336

7. forecast versus actual costs of the environmental planning. 337

3.3 Risks of Non-performance 338

In the event that the actual results of the Investment Portfolio do not produce a positive NPV or a PI of at least 1.0, the following will occur: 339

(a) the utility will be required to provide a complete variance explanation in its rates case and the Board will determine whether or not an acceptable explanation has been provided; and 340

(b) the implications of a negative NPV or PI less than 1.0 will be determined by the Board on a case by case basis. 341

4. CUSTOMER CONNECTION AND CONTRIBUTION POLICIES 342

The utilities will maintain a clear set of common Board-approved Customer Connection and Con- 343
tribution in Aid Policies.

The criteria for contributions in aid of construction for service lines and mains will apply to all 344
customer classes. If there is a reasonable expectation of further expansion, the contribution in aid of construction will take into account the future load growth potential and timing of any such expansion.

The Customer Connection and Contribution in Aid Policies shall, as a minimum, include the fol- 345
lowing:

- Requirements for payment for all, or part, of a customer service line connection, including 346
the specific criteria and the quantum of, or formula for calculating, the total or excess service line fees and other charges.
- Requirements for contributions in aid of construction for connection of individual custom- 347
ers, subdivisions or communities requiring main extensions that would not otherwise be included in the Investment or Rolling Project Portfolios.
- Requirements for contributions in aid of construction for expansion projects dominated by 348
one or more large volume customers.

5. ENVIRONMENTAL REQUIREMENTS FOR DISTRIBUTION FOR SYSTEM EXPANSION PROJECTS 349

The planning principles described in the Board's "Environmental Guidelines for the Location, 350
Construction, and Operation of Hydrocarbon Pipelines and Facilities In Ontario (1995)" shall also apply to distribution expansion projects undertaken by the utilities. The level of detail required, the degree of public consultation and the level of alternative route/site evaluation should be determined based on a review of the environmental (biophysical and socio-economic) significance of features potentially impacted by a proposed project.

Was Appendix, page 8 351
The utilities shall apply environmental screening criteria to determine when significant features may be impacted during the construction or the operation of the facility. Corresponding planning, documentation, and reporting requirements are to be applied depending on the impacts expected as determined through the screening process.

Once the study area for the project is determined, a regional officer of the utility who is familiar 352
with the study area and has been trained in environmental matters, shall identify potential impacts through the screening process and determine the level of planning required. Depending on the

significance of the potential impacts anticipated, the planning requirements may involve environmental specialists of the utility, external consultants or other affected parties.

All provincial and local agency requirements (permits, licences) shall be obtained where necessary and the utilities shall apply their standard guidelines, drawings, and specifications. 353

6. DOCUMENTATION, RECORD KEEPING AND REPORTING 354

The utilities will maintain documentation for all projects which are to be included in the Rolling Project Portfolio. A record of the DCF analysis conducted for each project in the Rolling Project Portfolio shall be available for review upon request of the Board. The performance tracking of individual projects shall be as described in Section 3 of these Guidelines. 355

The utilities will maintain a record of the environmental planning, documentation and reporting requirements associated with all projects and Environmental Reports for those projects deemed to have significant environmental impacts. 356

For all expansion projects in the Rolling Project Portfolio with a capital cost greater than $500,000 ("major projects") the utilities shall file the NPV and DCF analysis in each rate case and shall keep a record of forecast and actual customer attachments for a period of three years after construction is completed. In addition, the utilities shall also file in each rate case, the NPV and DCF analysis for all major projects planned for the test year. Upon request of the Board, the utilities shall file forecast and actual customer attachments for major projects. 357

The utilities shall file quarterly with the Board Secretary, the updated monthly Rolling Project Portfolio results immediately upon completing the calculations. 358

Was Appendix, schedule page 1 359

SCHEDULE1 DISCOUNTED CASH FLOW METHODOLOGY

360

<u>Net Present Value ("NPV")</u> = *Present Value ("PV") of Operating Cash Flow + PV of CCA Tax Shield - PV of Capital*

<u>Profitability Index ("PI")</u> = *<u>PV of Operating Cash Flow + PV of CCA Tax Shield</u>*

(PV of Capital)

361

1. <u>PV of Operating Cash Flow</u> = *PV of Net Operating Cash (before taxes) - PV of Taxes*

a)	PV of Net Operating Cash	=	PV of Net Operating Cash Discounted at the Company's discount rate for the customer revenue horizon. Mid-year discounting is applied.
	Net Operating Cash	=	*(Annual Gas Revenue - Annual Gas Costs - Annual O&M)*
	Annual Gas Revenue	=	*Customer Additions * Consumption Estimates per Customer * Revenue Rate per m^3*
	Annual Gas Cost	=	*Customer Additions * Consumption Estimates per Customer * Gas Costs per m^3 net of commodity costs*
	Annual O&M	=	*Customer Additions * Annual Marginal O&M Cost/customer*
			Was Appendix, schedule page 2 362
b)	PV of Taxes	=	PV of Municipal Taxes + PV of Capital Taxes + PV of Income Taxes (before Interest tax shield)
	Annual Municipal Tax	=	*Municipal Tax Rate * (Total Capital Cost)*
	Total Capital Cost	=	*(Mains Investment + Customer Related Investment + Overheads at portfolio level)*
	Annual Capital Taxes	=	*(Capital Tax Rate) * (Closing Undepreciated Capital Cost Balance)*
	Annual Capital Tax	=	*(Capital Tax Rate) * (Net Operating Cash - Annual Municipal Tax - Annual Capital Tax)*

The Capital Tax Rate is a combination of the Provincial Capital Tax Rate and the Large Corporation Tax (Grossed up for income tax effect where appropriate).

Note: Above is discounted, using mid-year discounting, over the customer revenue horizon. 363

364

2. PV of Capital = *PV of (Total Annual Capital Expenditures - Annual Contributions)*

a) PV of Total Annual Capital Expenditures

Total Annual Capital Expenditures over the customer's revenue horizon discounted to time zero

Total Annual Capital Expenditure = *(Mains Investment + Customer Specific Capital + Overheads at the Portfolio level)*

Was Appendix, schedule page 3 365

b) Annual Contributions

Annual Contributions = *Cash payments (or principal portions of payments over time) received as Contributions in Aid of Construction*

Note: Above is discounted to the beginning of year one over the customer addition horizon. 366

367

3. PV of CCA Tax Shield

PV of the CCA Tax Shield on [Total Annual Capital]

The PV of the perpetual tax shield may be calculated as:

$$\textit{PV at time zero of}: \quad \frac{[(\textit{Income Tax Rate}) * (\textit{CCA Rate}) * \textit{Annual Total Capital}]}{(\textit{CCA Rate} + \textit{Discount Rate})}$$

or,

Calculated annually and present valued in the PV of Taxes calculation.

Note: An adjustment is added to account for the $^{1}/_{2}$ year CCA rule. 368

369

4. Discount Rate

PV is calculated with an incremental, after-tax discount rate.

North-Bay Northshore and Peninsula Roads

Classification	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Total	Ultimate Potential	Total Attachments % Potential
Residential Conversion	34	30	12	8	6	8	7	8	7	6	126	341	37%
Residential - Seasonal	1	1	1	1	1	0	0	0	0	0	5	50	10%
Small Commercial	1	1	1	0	0	0	0	0	0	0	3	3	100%
Total	36	32	14	9	7	8	7	8	7	6	134	394	34%

NORTH-BAY NORTH SHORE AND PENINSULA ROADS

	Year	1	2	3	4	5	6	7	8	9	10
Proposed Capital ($000's)	Total										
Pipeline & Station Capital	8,124	8,124									
Service, M&R Installation	1,971	524	473	207	133	103	118	103	118	103	89
Total	10,095	8,648	473	207	133	103	118	103	118	103	89

Northshore and Peninsula Road
InService Date: Nov-01-2020

Project Year ($000's)	1	2	3	4	5	6	7	8	9	10
Cash Inflow										
SES Revenue	10	27	39	45	49	53	56	60	64	68
ITE Revenue	16	16	16	16	16	16	16	16	16	16
Distribution Revenue	9	25	35	40	44	48	51	55	58	61
Expenses:										
O & M Expense	(1)	(4)	(6)	(7)	(8)	(8)	(9)	(10)	(11)	(12)
Municipal Tax	(28)	(28)	(28)	(28)	(28)	(28)	(28)	(28)	(28)	(28)
Income Tax	22	-	(5)	(7)	(9)	(9)	(10)	(11)	(12)	(13)
Net Cash Inflow	28	36	51	59	64	72	76	82	87	92
Cash Outflow										
Incremental Capital	(22)	473	207	133	103	118	103	118	103	89
Change in Working Capital	-	-	-	-	-	-	-	-	-	-
Cash Outflow	(22)	473	207	133	103	118	103	118	103	89
Cumulative Net Present Value										
Cash Inflow	27	61	107	158	210	265	321	379	437	495
Cash Outflow	(22)	429	617	731	816	909	986	1,069	1,139	1,196
NPV By Year	49	(368)	(510)	(573)	(606)	(644)	(665)	(690)	(702)	(701)
Project NPV	12									
Profitability Index										
By Year PI	-1.23	0.14	0.17	0.22	0.26	0.29	0.33	0.35	0.38	0.41
Project PI	1.01									

Northshore and Peninsula Road
InService Date: Nov-01-2020

Project Year ($000's)	11	12	13	14	15	16	17	18	19	20
Cash Inflow										
SES Revenue	69	69	69	69	69	69	69	69	69	69
ITE Revenue	-	-	-	-	-	-	-	-	-	-
Distribution Revenue	63	63	63	63	63	63	63	63	63	63
Expenses:										
O & M Expense	(12)	(12)	(13)	(13)	(13)	(13)	(14)	(14)	(14)	(14)
Municipal Tax	(28)	(28)	(28)	(28)	(28)	(28)	(28)	(28)	(28)	(28)
Income Tax	(10)	(11)	(11)	(12)	(13)	(13)	(14)	(14)	(15)	(15)
Net Cash Inflow	82	81	80	79	78	78	76	76	75	75
Cash Outflow										
Incremental Capital	-	-	-	-	-	-	-	-	-	-
Change in Working Capital	-	-	-	-	-	-	-	-	-	-
Cash Outflow	-	-	-	-	-	-	-	-	-	-
Cumulative Net Present Value										
Cash Inflow	545	591	634	675	714	750	784	816	847	875
Cash Outflow	1,196	1,196	1,196	1,196	1,196	1,196	1,196	1,196	1,196	1,196
NPV By Year	(651)	(605)	(562)	(521)	(482)	(446)	(412)	(380)	(349)	(321)
Project NPV										
Profitability Index										
By Year PI	0.46	0.49	0.53	0.56	0.60	0.63	0.66	0.68	0.71	0.73
Project PI										

Northshore and Peninsula Road
InService Date: Nov-01-2020

Project Year ($000's)	21	22	23	24	25	26	27	28	29	30
Cash Inflow										
SES Revenue	69	69	69	69	69	69	69	69	69	69
ITE Revenue	-	-	-	-	-	-	-	-	-	-
Distribution Revenue	63	63	63	63	63	63	63	63	63	63
Expenses:										
O & M Expense	(15)	(15)	(15)	(15)	(16)	(16)	(16)	(16)	(17)	(17)
Municipal Tax	(28)	(28)	(28)	(28)	(28)	(28)	(28)	(28)	(28)	(28)
Income Tax	(16)	(16)	(17)	(17)	(17)	(18)	(18)	(18)	(18)	(19)
Net Cash Inflow	73	73	72	72	71	70	70	70	69	68
Cash Outflow										
Incremental Capital	-	-	-	-	-	-	-	-	-	-
Change in Working Capital	-	-	-	-	-	-	-	-	-	-
Cash Outflow	-	-	-	-	-	-	-	-	-	-
Cumulative Net Present Value										
Cash Inflow	902	928	952	974	996	1,016	1,035	1,053	1,070	1,087
Cash Outflow	1,196	1,196	1,196	1,196	1,196	1,196	1,196	1,196	1,196	1,196
NPV By Year	(294)	(268)	(244)	(222)	(200)	(180)	(161)	(143)	(126)	(109)
Project NPV										
Profitability Index										
By Year PI	0.75	0.78	0.80	0.81	0.83	0.85	0.87	0.88	0.89	0.91
Project PI										

Northshore and Peninsula Road
InService Date: Nov-01-2020

Project Year ($000's)	31	32	33	34	35	36	37	38	39	40
Cash Inflow										
SES Revenue	69	69	69	69	69	69	69	69	69	69
ITE Revenue	-	-	-	-	-	-	-	-	-	-
Distribution Revenue	63	63	63	63	63	63	63	63	63	63
Expenses:										
O & M Expense	(17)	(17)	(18)	(18)	(18)	(18)	(18)	(18)	(18)	(18)
Municipal Tax	(28)	(28)	(28)	(28)	(28)	(28)	(28)	(28)	(28)	(28)
Income Tax	(19)	(19)	(19)	(19)	(19)	(20)	(20)	(20)	(20)	(20)
Net Cash Inflow	68	68	67	67	67	66	66	66	66	66
Cash Outflow										
Incremental Capital	-	-	-	-	-	-	-	-	-	-
Change in Working Capital	-	-	-	-	-	-	-	-	-	-
Cash Outflow	-	-	-	-	-	-	-	-	-	-
Cumulative Net Present Value										
Cash Inflow	1,102	1,116	1,130	1,143	1,155	1,167	1,178	1,188	1,198	1,208
Cash Outflow	1,196	1,196	1,196	1,196	1,196	1,196	1,196	1,196	1,196	1,196
NPV By Year	(94)	(80)	(66)	(53)	(41)	(29)	(18)	(8)	2	12
Project NPV										
Profitability Index										
By Year PI	0.92	0.93	0.94	0.96	0.97	0.98	0.98	0.99	1.00	1.01
Project PI										

Northshore and Peninsula Roads

(Project Specific DCF Analysis)

Stage 1 DCF - Listing of Key Input Parameters, Values and Assumptions ($000'S)

Discounting Assumptions			
Project Time Horizon			40 years commencing at facilities in-service date of 01 Nov 20
Discount Rate			Incremental after-tax weighted average After Tax Cost of Capital of 5.02%
Key DCF Input Parameters, Values and Assumptions			
Net Cash Inflow:			
Incremental Revenue:			
Incremental Distribution Revenues			Approved per EB-2019-0194 Effective January 1, 2020
Operating and Maintenance Expense			Estimated incremental cost
Incremental Tax Expenses:			
Municipal Tax			Estimated incremental cost
Income Tax Rate			26.50%
CCA Rates:			
CCA Classes:	CCA Class	CCA Rate	Declining balance rates by CCA class: Accelerated CCA (Bill C-97) included.
Distribution System	51	6%	
Dist'n Mains (Plastic)	51	6%	
Customer Services & MRI	51	6%	
Cash Outflow:			
Incremental Capital Costs Attributed			Refer to Exhibit B, Tab 2, Schedule 5b
Change in Working Capital			5.051% applied to O&M

ENBRIDGE GAS INC.

Answer to Interrogatory from
School Energy Coalition (SEC)

Interrogatory

Reference:

2-6-1, p.48-49

Questions(s):

With respect to customer connection feasibility:

a) For each year between 2013 and 2024, please provide the annual investment portfolio PI. Please provide all underlying calculations.

b) Please provide the most recent 12-month rolling project portfolio (RPP) PI. Please provide all underlying calculations.

Response:

The following response has been updated to reflect the Capital Update provided at Exhibit 2, Tab 5, Schedule 4, filed on June 16, 2023. /u

Please see Table 1. Please note that the updated PI values for 2023 and 2024 investment portfolios are lower than originally filed. The reason for this decrease is the increase in the customer connections capital forecast, which is driven by inflationary pressures for these years. /u

Table 1

EGI	PV of Cash Inflows1 ($million)	PV of Cash Outflows2 ($million)	PI	
2013	$254.8	$209.1	1.22	
2014	$246.1	$219.8	1.12	
2015	$228.9	$217.0	1.06	
2016	$243.2	$224.3	1.08	
2017	$253.3	$199.2	1.27	
2018	$224.3	$209.2	1.07	
2019	$263.9	$241.6	1.09	
2020	$265.1	$250.9	1.06	
2021	$262.9	$301.3	0.87	
2022	$290.1	$312.7	0.93	
2023	$266.7	$293.5	0.91	/u
2024	$340.6	$315.3	1.08	/u

1-Present value of revenues net of ongoing operating costs plus CCA tax shield
2-Present value of capital investments

b) Please see Table 2 for the most recent 12-month Rolling Project Portfolio PI.

Table 2

Cash Inflow ($million)	Cash Outflow ($million)	PI
$333.4	$215.8	1.54

ENBRIDGE GAS INC.

Answer to Undertaking from
School Energy Coalition (SEC)

Undertaking

Tr: 85

To provide the full underlying calculations for the PI's for the years as requested in the original interrogatory.

Response:

Please see Attachment 1 containing the underlying numbers and calculations associated with Enbridge Gas's Investment Portfolio[1] PIs provided in response at Exhibit I.2.6-SEC-118, Table 1 for the years 2013 to 2024. The PI of the investment portfolio is calculated based on a discounted cashflow method (DCF) as per E.B.O 188 guidelines.

Detailed calculations of the cash inflows, cash outflows and PI for each year from 2013 to 2024 are provided at Attachment 1.

Similar details cannot be provided for the Rolling Project Portfolio[2] (RPP) in response at Exhibit I.2.6-SEC-118, Table 2, for the following reasons. Unlike the Investment Portfolio, which is calculated on an aggregate basis, the PI of the RPP is based on the cumulative outcomes of the individual feasibility calculations for all new connection projects over a rolling 12-month period. While Enbridge Gas does maintain the details, there are more than one thousand projects in the RPP, and the underlying data is captured in individual models. It would be very time consuming to extract all the details from the individual models and aggregate the information up to the level of cash inflows, cash outflows and PI. As such, Enbridge Gas respectfully declines to provide the calculations as requested.

[1] Investment Portfolio (IP) calculations include all costs and revenues associated with all new distribution customers attached in a particular year. The IP also includes new customers attaching to existing mains (infills).

[2] Rolling Project Portfolio (RPP) is an accumulation of the new business capital requisitions that are issued and approved within a 12-month period. This includes all future customer attachments, revenues, and costs based on the life cycle of each project. RPP does not include service connecting to existing mains.

Investment Portfolio - 2021

($millions)	Year	1	2	3	4	5	6	7	8	9	10
Cash Inflows	**Total**										
Revenue:											
Distribution Revenue	883.9	11.0	23.0	23.0	23.0	23.0	23.0	23.0	23.0	23.0	23.0
Expenses:											
O & M Expense	(154.4)	(2.0)	(3.9)	(3.9)	(3.9)	(3.9)	(3.9)	(3.9)	(3.9)	(3.9)	(3.9)
Municipal Tax	(66.9)	(1.7)	(1.7)	(1.7)	(1.7)	(1.7)	(1.7)	(1.7)	(1.7)	(1.7)	(1.7)
Income Tax	(110.8)	5.3	(0.6)	(0.9)	(1.2)	(1.4)	(1.6)	(1.8)	(2.0)	(2.2)	(2.4)
Total Cash Inflows	551.8	12.7	16.8	16.5	16.2	16.0	15.8	15.6	15.4	15.2	15.0
Cash Outflows											
Incremental Capital	(302.6)	(302.6)	-	-	-	-	-	-	-	-	-
Change in Working Capital	(0.0)	(0.0)	0.0	-	-	-	-	-	-	-	-
Total Cash Outflows	(302.6)	(302.6)	0.0	-	-	-	-	-	-	-	-
Net Present Value											
PV of Cash Inflows	262.9	12.3	16.0	15.0	14.1	13.2	12.5	11.7	11.0	10.4	9.8
PV of Cash Outflows	(301.3)	(301.3)	(0.0)	-	-	-	-	-	-	-	-
Total NPV	(38.4)	(289.0)	15.9	15.0	14.1	13.2	12.5	11.7	11.0	10.4	9.8
Profitability Index	**0.87**										

Investment Portfolio - 2021

($millions)	Year	11	12	13	14	15	16	17	18	19	20
Cash Inflows	**Total**										
Revenue:											
Distribution Revenue	883.9	23.0	23.0	23.0	23.0	23.0	23.0	23.0	23.0	23.0	23.0
Expenses:											
O & M Expense	(154.4)	(3.9)	(3.9)	(3.9)	(3.9)	(3.9)	(3.9)	(3.9)	(3.9)	(3.9)	(3.9)
Municipal Tax	(66.9)	(1.7)	(1.7)	(1.7)	(1.7)	(1.7)	(1.7)	(1.7)	(1.7)	(1.7)	(1.7)
Income Tax	(110.8)	(2.6)	(2.7)	(2.9)	(3.0)	(3.1)	(3.2)	(3.4)	(3.5)	(3.6)	(3.7)
Total Cash Inflows	551.8	14.8	14.7	14.5	14.4	14.3	14.2	14.0	13.9	13.8	13.7
Cash Outflows											
Incremental Capital	(302.6)	-	-	-	-	-	-	-	-	-	-
Change in Working Capital	(0.0)	-	-	-	-	-	-	-	-	-	-
Total Cash Outflows	(302.6)	-	-	-	-	-	-	-	-	-	-
Net Present Value											
PV of Cash Inflows	262.9	9.3	8.7	8.2	7.8	7.4	7.0	6.6	6.2	5.9	5.6
PV of Cash Outflows	(301.3)	-	-	-	-	-	-	-	-	-	-
Total NPV	(38.4)	9.3	8.7	8.2	7.8	7.4	7.0	6.6	6.2	5.9	5.6
Profitability Index	**0.87**										

Investment Portfolio - 2021

($millions)	Year	21	22	23	24	25	26	27	28	29	30
Cash Inflows	**Total**										
Revenue:											
Distribution Revenue	883.9	21.9	21.8	21.8	21.8	21.8	21.8	21.8	21.8	21.8	21.8
Expenses:											
O & M Expense	(154.4)	(3.9)	(3.9)	(3.9)	(3.9)	(3.9)	(3.9)	(3.9)	(3.9)	(3.9)	(3.9)
Municipal Tax	(66.9)	(1.7)	(1.7)	(1.7)	(1.7)	(1.7)	(1.7)	(1.7)	(1.7)	(1.7)	(1.7)
Income Tax	(110.8)	(3.1)	(3.2)	(3.2)	(3.3)	(3.4)	(3.4)	(3.5)	(3.6)	(3.6)	(3.7)
Total Cash Inflows	551.8	13.2	13.1	13.0	12.9	12.8	12.8	12.7	12.7	12.6	12.6
Cash Outflows											
Incremental Capital	(302.6)	-	-	-	-	-	-	-	-	-	-
Change in Working Capital	(0.0)	0.0	-	-	-	-	-	-	-	-	-
Total Cash Outflows	(302.6)	0.0	-	-	-	-	-	-	-	-	-
Net Present Value											
PV of Cash Inflows	262.9	5.0	4.7	4.5	4.3	4.0	3.8	3.6	3.4	3.3	3.1
PV of Cash Outflows	(301.3)	0.0	-	-	-	-	-	-	-	-	-
Total NPV	(38.4)	5.0	4.7	4.5	4.3	4.0	3.8	3.6	3.4	3.3	3.1
Profitability Index	**0.87**										

Investment Portfolio - 2021

($millions)	Year	31	32	33	34	35	36	37	38	39	40
Cash Inflows	**Total**										
Revenue:											
Distribution Revenue	883.9	21.8	21.8	21.8	21.8	21.8	21.8	21.8	21.8	21.8	21.8
Expenses:											
O & M Expense	(154.4)	(3.9)	(3.9)	(3.9)	(3.9)	(3.9)	(3.9)	(3.9)	(3.9)	(3.9)	(3.9)
Municipal Tax	(66.9)	(1.7)	(1.7)	(1.7)	(1.7)	(1.7)	(1.7)	(1.7)	(1.7)	(1.7)	(1.7)
Income Tax	(110.8)	(3.7)	(3.8)	(3.8)	(3.8)	(3.9)	(3.9)	(3.9)	(4.0)	(4.0)	(1.7)
Total Cash Inflows	551.8	12.5	12.5	12.4	12.4	12.4	12.3	12.3	12.3	12.2	14.5
Cash Outflows											
Incremental Capital	(302.6)	-	-	-	-	-	-	-	-	-	-
Change in Working Capital	(0.0)	-	-	-	-	-	-	-	-	-	-
Total Cash Outflows	(302.6)	-	-	-	-	-	-	-	-	-	-
Net Present Value											
PV of Cash Inflows	262.9	3.0	2.8	2.7	2.5	2.4	2.3	2.2	2.1	2.0	2.4
PV of Cash Outflows	(301.3)	-	-	-	-	-	-	-	-	-	-
Total NPV	(38.4)	3.0	2.8	2.7	2.5	2.4	2.3	2.2	2.1	2.0	2.4
Profitability Index	**0.87**										

Investment Portfolio - 2022

($millions)	Year	1	2	3	4	5	6	7	8	9	10
Cash Inflows	**Total**										
Revenue:											
Distribution Revenue	936.3	11.4	25.4	25.4	25.4	25.4	25.4	25.4	25.4	25.4	25.4
Expenses:											
O & M Expense	(168.1)	(2.1)	(4.3)	(4.3)	(4.3)	(4.3)	(4.3)	(4.3)	(4.3)	(4.3)	(4.3)
Municipal Tax	(53.1)	(1.3)	(1.3)	(1.3)	(1.3)	(1.3)	(1.3)	(1.3)	(1.3)	(1.3)	(1.3)
Income Tax	(110.9)	5.4	(0.7)	(1.0)	(1.2)	(1.5)	(1.7)	(1.9)	(2.1)	(2.3)	(2.5)
Total Cash Inflows	604.3	13.3	19.1	18.8	18.6	18.3	18.1	17.9	17.7	17.5	17.3
Cash Outflows											
Incremental Capital	(314.0)	(314.0)	-	-	-	-	-	-	-	-	-
Change in Working Capital	(0.0)	(0.1)	0.0	-	-	-	-	-	-	-	-
Total Cash Outflows	(314.0)	(314.0)	0.0	-	-	-	-	-	-	-	-
Net Present Value											
PV of Cash Inflows	290.1	13.0	17.8	16.7	15.7	14.8	14.0	13.2	12.4	11.7	11.1
PV of Cash Outflows	(312.7)	(312.7)	(0.1)	-	-	-	-	-	-	-	-
Total NPV	(22.6)	(299.6)	17.7	16.7	15.7	14.8	14.0	13.2	12.4	11.7	11.1
Profitability Index	**0.93**										

Investment Portfolio - 2022

($millions)	Year	11	12	13	14	15	16	17	18	19	20
Cash Inflows	**Total**										
Revenue:											
Distribution Revenue	936.3	25.4	25.4	25.4	25.4	25.4	25.4	25.4	25.4	25.4	25.4
Expenses:											
O & M Expense	(168.1)	(4.3)	(4.3)	(4.3)	(4.3)	(4.3)	(4.3)	(4.3)	(4.3)	(4.3)	(4.3)
Municipal Tax	(53.1)	(1.3)	(1.3)	(1.3)	(1.3)	(1.3)	(1.3)	(1.3)	(1.3)	(1.3)	(1.3)
Income Tax	(110.9)	(2.6)	(2.8)	(2.9)	(3.1)	(3.2)	(3.3)	(3.5)	(3.6)	(3.7)	(3.8)
Total Cash Inflows	604.3	17.1	17.0	16.8	16.7	16.6	16.4	16.3	16.2	16.1	16.0
Cash Outflows											
Incremental Capital	(314.0)	-	-	-	-	-	-	-	-	-	-
Change in Working Capital	(0.0)	-	-	-	-	-	-	-	-	-	-
Total Cash Outflows	(314.0)	-	-	-	-	-	-	-	-	-	-
Net Present Value											
PV of Cash Inflows	290.1	10.5	9.9	9.4	8.9	8.4	7.9	7.5	7.1	6.8	6.4
PV of Cash Outflows	(312.7)	-	-	-	-	-	-	-	-	-	-
Total NPV	(22.6)	10.5	9.9	9.4	8.9	8.4	7.9	7.5	7.1	6.8	6.4
Profitability Index	**0.93**										

Investment Portfolio - 2022

($millions)	Year	21	22	23	24	25	26	27	28	29	30
Cash Inflows	**Total**										
Revenue:											
Distribution Revenue	936.3	22.2	22.1	22.1	22.1	22.1	22.1	22.1	22.1	22.1	22.1
Expenses:											
O & M Expense	(168.1)	(4.3)	(4.2)	(4.2)	(4.2)	(4.2)	(4.2)	(4.2)	(4.2)	(4.2)	(4.2)
Municipal Tax	(53.1)	(1.3)	(1.3)	(1.3)	(1.3)	(1.3)	(1.3)	(1.3)	(1.3)	(1.3)	(1.3)
Income Tax	(110.9)	(3.0)	(3.1)	(3.2)	(3.2)	(3.3)	(3.4)	(3.4)	(3.5)	(3.5)	(3.6)
Total Cash Inflows	604.3	13.6	13.5	13.4	13.3	13.3	13.2	13.1	13.1	13.0	13.0
Cash Outflows											
Incremental Capital	(314.0)	-	-	-	-	-	-	-	-	-	-
Change in Working Capital	(0.0)	0.0	0.0	-	-	-	-	-	-	-	-
Total Cash Outflows	(314.0)	0.0	0.0	-	-	-	-	-	-	-	-
Net Present Value											
PV of Cash Inflows	290.1	5.2	4.9	4.7	4.4	4.2	4.0	3.8	3.6	3.4	3.2
PV of Cash Outflows	(312.7)	0.0	0.0	-	-	-	-	-	-	-	-
Total NPV	(22.6)	5.2	4.9	4.7	4.4	4.2	4.0	3.8	3.6	3.4	3.2
Profitability Index	**0.93**										

Investment Portfolio - 2022

($millions)	Year	31	32	33	34	35	36	37	38	39	40
Cash Inflows	**Total**										
Revenue:											
Distribution Revenue	936.3	22.1	22.1	22.1	22.1	22.1	22.1	22.1	22.1	22.1	22.1
Expenses:											
O & M Expense	(168.1)	(4.2)	(4.2)	(4.2)	(4.2)	(4.2)	(4.2)	(4.2)	(4.2)	(4.2)	(4.2)
Municipal Tax	(53.1)	(1.3)	(1.3)	(1.3)	(1.3)	(1.3)	(1.3)	(1.3)	(1.3)	(1.3)	(1.3)
Income Tax	(110.9)	(3.6)	(3.7)	(3.7)	(3.8)	(3.8)	(3.8)	(3.9)	(3.9)	(3.9)	(1.6)
Total Cash Inflows	604.3	12.9	12.9	12.8	12.8	12.8	12.7	12.7	12.7	12.6	14.9
Cash Outflows											
Incremental Capital	(314.0)	-	-	-	-	-	-	-	-	-	-
Change in Working Capital	(0.0)	-	-	-	-	-	-	-	-	-	-
Total Cash Outflows	(314.0)	-	-	-	-	-	-	-	-	-	-
Net Present Value											
PV of Cash Inflows	290.1	3.1	2.9	2.8	2.7	2.5	2.4	2.3	2.2	2.1	2.6
PV of Cash Outflows	(312.7)	-	-	-	-	-	-	-	-	-	-
Total NPV	(22.6)	3.1	2.9	2.8	2.7	2.5	2.4	2.3	2.2	2.1	2.6
Profitability Index	**0.93**										

Investment Portfolio - 2023

($millions)	Year	1	2	3	4	5	6	7	8	9	10
Cash Inflows	**Total**										
Revenue:											
Distribution Revenue	919.9	11.3	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5
Expenses:											
O & M Expense	(157.1)	(2.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)
Municipal Tax	(42.4)	(1.1)	(1.1)	(1.1)	(1.1)	(1.1)	(1.1)	(1.1)	(1.1)	(1.1)	(1.1)
Income Tax	(126.9)	3.9	(1.4)	(1.7)	(1.9)	(2.1)	(2.3)	(2.4)	(2.6)	(2.8)	(2.9)
Total Cash Inflows	593.5	12.2	18.0	17.8	17.6	17.4	17.2	17.0	16.8	16.7	16.5
Cash Outflows											
Incremental Capital	(254.8)	(254.8)	-	-	-	-	-	-	-	-	-
Change in Working Capital	(0.0)	(0.0)	0.0	-	-	-	-	-	-	-	-
Total Cash Outflows	(254.9)	(254.9)	0.0	-	-	-	-	-	-	-	-
Net Present Value											
PV of Cash Inflows	270.8	11.9	16.7	15.7	14.8	13.9	13.1	12.3	11.6	10.9	10.3
PV of Cash Outflows	(254.8)	(254.7)	(0.0)	-	-	-	-	-	-	-	-
Total NPV	16.0	(242.8)	16.7	15.7	14.8	13.9	13.1	12.3	11.6	10.9	10.3
Profitability Index	**1.06**										

Investment Portfolio - 2023

($millions)	Year	11	12	13	14	15	16	17	18	19	20
Cash Inflows	**Total**										
Revenue:											
Distribution Revenue	919.9	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5
Expenses:											
O & M Expense	(157.1)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)
Municipal Tax	(42.4)	(1.1)	(1.1)	(1.1)	(1.1)	(1.1)	(1.1)	(1.1)	(1.1)	(1.1)	(1.1)
Income Tax	(126.9)	(3.0)	(3.2)	(3.3)	(3.4)	(3.5)	(3.6)	(3.7)	(3.8)	(3.9)	(3.9)
Total Cash Inflows	593.5	16.4	16.3	16.2	16.0	15.9	15.8	15.7	15.7	15.6	15.5
Cash Outflows											
Incremental Capital	(254.8)	-	-	-	-	-	-	-	-	-	-
Change in Working Capital	(0.0)	-	-	-	-	-	-	-	-	-	-
Total Cash Outflows	(254.9)	-	-	-	-	-	-	-	-	-	-
Net Present Value											
PV of Cash Inflows	270.8	9.7	9.2	8.7	8.2	7.8	7.3	6.9	6.6	6.2	5.9
PV of Cash Outflows	(254.8)	-	-	-	-	-	-	-	-	-	-
Total NPV	16.0	9.7	9.2	8.7	8.2	7.8	7.3	6.9	6.6	6.2	5.9
Profitability Index	**1.06**										

Investment Portfolio - 2023

($millions)	Year	21	22	23	24	25	26	27	28	29	30
Cash Inflows	**Total**										
Revenue:											
Distribution Revenue	919.9	22.2	22.1	22.1	22.1	22.1	22.1	22.1	22.1	22.1	22.1
Expenses:											
O & M Expense	(157.1)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)
Municipal Tax	(42.4)	(1.1)	(1.1)	(1.1)	(1.1)	(1.1)	(1.1)	(1.1)	(1.1)	(1.1)	(1.1)
Income Tax	(126.9)	(3.4)	(3.5)	(3.5)	(3.6)	(3.7)	(3.7)	(3.8)	(3.8)	(3.8)	(3.9)
Total Cash Inflows	593.5	13.8	13.7	13.6	13.5	13.5	13.4	13.4	13.3	13.3	13.2
Cash Outflows											
Incremental Capital	(254.8)	-	-	-	-	-	-	-	-	-	-
Change in Working Capital	(0.0)	0.0	0.0	-	-	-	-	-	-	-	-
Total Cash Outflows	(254.9)	0.0	0.0	-	-	-	-	-	-	-	-
Net Present Value											
PV of Cash Inflows	270.8	5.0	4.7	4.4	4.2	4.0	3.8	3.6	3.4	3.2	3.1
PV of Cash Outflows	(254.8)	0.0	0.0	-	-	-	-	-	-	-	-
Total NPV	16.0	5.0	4.7	4.4	4.2	4.0	3.8	3.6	3.4	3.2	3.1
Profitability Index	**1.06**										

Investment Portfolio - 2023

($millions)	Year	31	32	33	34	35	36	37	38	39	40
Cash Inflows	**Total**										
Revenue:											
Distribution Revenue	919.9	22.1	22.1	22.1	22.1	22.1	22.1	22.1	22.1	22.1	22.1
Expenses:											
O & M Expense	(157.1)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)
Municipal Tax	(42.4)	(1.1)	(1.1)	(1.1)	(1.1)	(1.1)	(1.1)	(1.1)	(1.1)	(1.1)	(1.1)
Income Tax	(126.9)	(3.9)	(4.0)	(4.0)	(4.0)	(4.1)	(4.1)	(4.1)	(4.1)	(4.2)	(2.2)
Total Cash Inflows	593.5	13.2	13.2	13.1	13.1	13.1	13.0	13.0	13.0	13.0	14.9
Cash Outflows											
Incremental Capital	(254.8)	-	-	-	-	-	-	-	-	-	-
Change in Working Capital	(0.0)	-	-	-	-	-	-	-	-	-	-
Total Cash Outflows	(254.9)	-	-	-	-	-	-	-	-	-	-
Net Present Value											
PV of Cash Inflows	270.8	2.9	2.8	2.6	2.5	2.4	2.2	2.1	2.0	1.9	2.2
PV of Cash Outflows	(254.8)	-	-	-	-	-	-	-	-	-	-
Total NPV	16.0	2.9	2.8	2.6	2.5	2.4	2.2	2.1	2.0	1.9	2.2
Profitability Index	**1.06**										

Investment Portfolio - 2024

($millions)	Year	1	2	3	4	5	6	7	8	9	10
Cash Inflows	**Total**										
Revenue:											
Distribution Revenue	1,114.8	13.5	30.6	30.6	30.6	30.6	30.6	30.6	30.6	30.6	30.6
Expenses:											
O & M Expense	(157.1)	(2.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)
Municipal Tax	(45.2)	(1.1)	(1.1)	(1.1)	(1.1)	(1.1)	(1.1)	(1.1)	(1.1)	(1.1)	(1.1)
Income Tax	(173.8)	1.6	(2.7)	(2.9)	(3.2)	(3.4)	(3.6)	(3.8)	(4.0)	(4.1)	(4.3)
Total Cash Inflows	738.8	11.9	22.8	22.6	22.4	22.1	21.9	21.7	21.6	21.4	21.2
Cash Outflows											
Incremental Capital	(271.3)	(271.3)	-	-	-	-	-	-	-	-	-
Change in Working Capital	(0.0)	(0.0)	0.0	-	-	-	-	-	-	-	-
Total Cash Outflows	(271.3)	(271.4)	0.0	-	-	-	-	-	-	-	-
Net Present Value											
PV of Cash Inflows	332.8	11.6	21.2	19.9	18.7	17.6	16.6	15.6	14.7	13.9	13.1
PV of Cash Outflows	(271.2)	(271.2)	(0.0)	-	-	-	-	-	-	-	-
Total NPV	61.5	(259.6)	21.1	19.9	18.7	17.6	16.6	15.6	14.7	13.9	13.1
Profitability Index	**1.23**										

Investment Portfolio - 2024

($millions)	Year	11	12	13	14	15	16	17	18	19	20
Cash Inflows	**Total**										
Revenue:											
Distribution Revenue	1,114.8	30.6	30.6	30.6	30.6	30.6	30.6	30.6	30.6	30.6	30.6
Expenses:											
O & M Expense	(157.1)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)
Municipal Tax	(45.2)	(1.1)	(1.1)	(1.1)	(1.1)	(1.1)	(1.1)	(1.1)	(1.1)	(1.1)	(1.1)
Income Tax	(173.8)	(4.4)	(4.6)	(4.7)	(4.8)	(4.9)	(5.1)	(5.2)	(5.3)	(5.3)	(5.4)
Total Cash Inflows	738.8	21.1	20.9	20.8	20.7	20.6	20.5	20.4	20.3	20.2	20.1
Cash Outflows											
Incremental Capital	(271.3)	-	-	-	-	-	-	-	-	-	-
Change in Working Capital	(0.0)	-	-	-	-	-	-	-	-	-	-
Total Cash Outflows	(271.3)	-	-	-	-	-	-	-	-	-	-
Net Present Value											
PV of Cash Inflows	332.8	12.3	11.6	11.0	10.4	9.8	9.3	8.8	8.3	7.8	7.4
PV of Cash Outflows	(271.2)	-	-	-	-	-	-	-	-	-	-
Total NPV	61.5	12.3	11.6	11.0	10.4	9.8	9.3	8.8	8.3	7.8	7.4
Profitability Index	**1.23**										

Investment Portfolio - 2024

($millions)	Year	21	22	23	24	25	26	27	28	29	30
Cash Inflows	**Total**										
Revenue:											
Distribution Revenue	1,114.8	26.1	25.9	25.9	25.9	25.9	25.9	25.9	25.9	25.9	25.9
Expenses:											
O & M Expense	(157.1)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)
Municipal Tax	(45.2)	(1.1)	(1.1)	(1.1)	(1.1)	(1.1)	(1.1)	(1.1)	(1.1)	(1.1)	(1.1)
Income Tax	(173.8)	(4.3)	(4.4)	(4.4)	(4.5)	(4.6)	(4.6)	(4.7)	(4.7)	(4.8)	(4.8)
Total Cash Inflows	738.8	16.6	16.5	16.4	16.4	16.3	16.3	16.2	16.1	16.1	16.0
Cash Outflows											
Incremental Capital	(271.3)	-	-	-	-	-	-	-	-	-	-
Change in Working Capital	(0.0)	0.0	0.0	-	-	-	-	-	-	-	-
Total Cash Outflows	(271.3)	0.0	0.0	-	-	-	-	-	-	-	-
Net Present Value											
PV of Cash Inflows	332.8	5.8	5.5	5.2	4.9	4.7	4.4	4.2	4.0	3.8	3.6
PV of Cash Outflows	(271.2)	0.0	0.0	-	-	-	-	-	-	-	-
Total NPV	61.5	5.8	5.5	5.2	4.9	4.7	4.4	4.2	4.0	3.8	3.6
Profitability Index	**1.23**										

Investment Portfolio - 2024

($millions)	Year	31	32	33	34	35	36	37	38	39	40
Cash Inflows	Total										
Revenue:											
Distribution Revenue	1,114.8	25.9	25.9	25.9	25.9	25.9	25.9	25.9	25.9	25.9	25.9
Expenses:											
O & M Expense	(157.1)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)
Municipal Tax	(45.2)	(1.1)	(1.1)	(1.1)	(1.1)	(1.1)	(1.1)	(1.1)	(1.1)	(1.1)	(1.1)
Income Tax	(173.8)	(4.9)	(4.9)	(4.9)	(5.0)	(5.0)	(5.0)	(5.1)	(5.1)	(5.1)	(3.0)
Total Cash Inflows	738.8	16.0	16.0	15.9	15.9	15.9	15.8	15.8	15.8	15.7	17.8
Cash Outflows											
Incremental Capital	(271.3)	-	-	-	-	-	-	-	-	-	-
Change in Working Capital	(0.0)	-	-	-	-	-	-	-	-	-	-
Total Cash Outflows	(271.3)	-	-	-	-	-	-	-	-	-	-
Net Present Value											
PV of Cash Inflows	332.8	3.4	3.2	3.0	2.9	2.7	2.6	2.4	2.3	2.2	2.5
PV of Cash Outflows	(271.2)	-	-	-	-	-	-	-	-	-	-
Total NPV	61.5	3.4	3.2	3.0	2.9	2.7	2.6	2.4	2.3	2.2	2.5
Profitability Index	**1.23**										

ENBRIDGE GAS INC.

Answer to Undertaking from
Energy Probe Research Foundation (EP)

Undertaking

Tr: 97

To confirm whether Enbridge is obliged to keep serving those customers as long as customers need natural gas.

Response:

Gas distributors in Ontario are obligated to provide service pursuant to the *Ontario Energy Board Act, 1998*, section 42:

> *Duties of gas transmitters and distributors*
>
> *Discontinuance of transmission or distribution*
> *42.(1) Subject to the Technical Standards and Safety Act, 2000 and the regulations made under that Act, and in the absence of an agreement to the contrary between the parties affected, no gas transmitter shall voluntarily discontinue transmitting gas to a gas distributor without leave of the Board. 1998, c. 15, Sched. B, s. 42 (1); 2002, c. 17, Sched. F, Table; 2003, c. 3, s. 32.*
>
> *Duty of gas distributor*
> *(2) Subject to the Public Utilities Act, the Technical Standards and Safety Act, 2000 and the regulations made under the latter Act, sections 80, 81, 82 and 83 of the Municipal Act, 2001 and sections 64, 65, 66 and 67 of the City of Toronto Act, 2006, a gas distributor shall provide gas distribution services to any building along the line of any of the gas distributor's distribution pipe lines upon the request in writing of the owner, occupant or other person in charge of the building. 2006, c. 32, Sched. C, s. 42.*

The *Ontario Energy Board Act, 1998* (OEB Act), section 42(3) also gives the OEB the authority to order that service be provided:

> *Order*
> *(3) Upon application, the Board may order a gas transmitter, gas distributor or storage company to provide any gas sale, transmission, distribution or storage service or cease to provide any gas sale service. 1998, c. 15, Sched. B, s. 42 (3).*

In addition to being subject to the laws referenced in section 42(2) of the OEB Act, a gas distributor's obligation to serve is subject to the gas distributor's terms and conditions of service approved by the OEB from time to time, such as feasibility and connection policies.

Pursuant to the *Municipal Franchises Act*, a gas distributor requires a municipal franchise agreement in order to provide gas distribution services to the inhabitants in a municipality. Franchise agreements are typically in the form of the OEB's Model Franchise Agreement and are in place for an initial term of 20 years and subject to renewal thereafter in accordance with sections 9 or 10 of the *Municipal Franchises Act*. Enbridge Gas has franchise agreements in place with 312 lower/single-tier municipalities and 27 upper-tier municipalities in Ontario.

Section 4 of the Model Franchise Agreement states:

> *c. At any time within two years prior to the expiration of this Agreement, either party may give notice to the other that it desires to enter into negotiations for a renewed franchise upon such terms and conditions as may be agreed upon. Until such renewal has been settled, the terms and conditions of this Agreement shall continue, notwithstanding the expiration of this Agreement. This shall not preclude either party from applying to the Ontario Energy Board for a renewal of the Agreement pursuant to section 10 of the Municipal Franchises Act.*

At Tr. Vol. 1 page 106, the Company witness indicated the municipality should have a choice of which energy their constituents could receive. To provide further context, as long as Enbridge Gas has customers in a municipality, it may seek approval from the OEB to renew the franchise agreement with the municipality, typically with the municipality's consent. However, if the municipality has concerns about the terms and conditions of renewal of a franchise agreement, Enbridge Gas may apply to the OEB pursuant to section 10 of the *Municipal Franchises Act* for a renewal.

ENBRIDGE GAS INC.

Answer to Undertaking from
School Energy Coalition (SEC)

Undertaking

Tr: 78

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

Response:

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

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

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

Updated Response: /u

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

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

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

Table 1

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

Table 1 Continued

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

Notes:

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

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

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

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

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

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

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

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

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

(i) Milverton and Rostock/Wartburg Community Expansion Project

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

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

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

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

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

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

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

(i) Delaware Nation of Moraviantown Community Expansion Project

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

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

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

(i) Prince Township Community Expansion Project

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

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

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

(i) Fenelon Falls Community Expansion Project

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

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

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

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

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

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

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

(i) Saugeen First Nation Community Expansion Project

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

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

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

(i) Northshore and Peninsula Rd Community Expansion Project

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

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

(i) Scugog Island First Nation Community Expansion Project

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

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

(i) Brunner (Perth East) Community Expansion Project

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

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

(i) Burk's Falls Community Expansion Project

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

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

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

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

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

(i) Stanley's Olde Maple Community Expansion Project

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

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

(i) Haldimand Shores Community Expansion Project

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

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

(i) Mohawk of Bay of Quinte Community Expansion Project

(ii) Budgeted Capital Cost($) [1]	$ 10,715,495
(iii) Forecast Cost ($) [2]	$ 10,715,495
(iv) Actual Capital Cost-to-date ($)	N/A
(v) Forecast final Capital Cost ($) [3]	$ 10,715,495

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

(i) Hidden Valley Community Expansion Project

(ii) Budgeted Capital Cost($) [1]	$ 3,463,661
(iii) Forecast Cost ($) [2]	$ 3,339,388
(iv) Actual Capital Cost-to-date ($)	N/A
(v) Forecast final Capital Cost ($) [3]	$ 3,339,388

		2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	Total
(vi) Forecast Customer Attachments (#/yr)		29	26	10	7	6	7	6	7	6	6	110
(vii) Actual Customer Attachment (#/yr) - Installed Services		N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0
(viii) Oriiginal Forecast PI	1.00											
(ix) Revised forecast PI based on the most recent forecast costs and customer attachment forecast	N/A											
(x) SES term	40											
(xi) If the PI in part (ix) is below 1.0, the forecast capital funding shortfall [4]	N/A											

(i) Selwyn Community Expansion Project

(ii) Budgeted Capital Cost($) [1]	$ 6,041,151
(iii) Forecast Cost ($) [2]	$ 4,502,425
(iv) Actual Capital Cost-to-date ($)	N/A
(v) Forecast final Capital Cost ($) [3]	$ 4,502,425

		2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	Total
(vi) Forecast Customer Attachments (#/yr)		34	19	12	7	5	4	2	2	1	1	87
(vii) Actual Customer Attachment (#/yr) - Installed Services		N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0
(viii) Oriiginal Forecast PI	1.00											
(ix) Revised forecast PI based on the most recent forecast costs and customer attachment forecast	N/A											
(x) SES term	40											
(xi) If the PI in part (ix) is below 1.0, the forecast capital funding shortfall [4]	N/A											

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

Cornwall Island First Nation Community Expansion Project

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

		Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Total
(vi) Forecast Customer Attachments (#/yr)		38	97	94	48	20	13	13	13	9	9	354
(viii) Oriiginal Forecast PI	1.0											
(x) SES term	40											

Hiawatha First Nation Community Expansion Project

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

		Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Total
(vi) Forecast Customer Attachments (#/yr)		29	59	57	16	14	10	10	8	5	5	213
(viii) Oriiginal Forecast PI	1.0											
(x) SES term	40											

Boblo Island Community Expansion Project

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

		Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Total
(vi) Forecast Customer Attachments (#/yr)		28	21	14	7	7	3	3	3	3	3	92
(viii) Oriiginal Forecast PI	1.0											
(x) SES term	40											

Cedar Springs Community Expansion Project

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

		Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Total
(vi) Forecast Customer Attachments (#/yr)		31	28	15	8	8	3	3	3	2	2	103
(viii) Oriiginal Forecast PI	1.0											
(x) SES term	40											

Neustadt Community Expansion Project

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

		Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Total
(vi) Forecast Customer Attachments (#/yr)		50	62	24	13	11	13	11	12	12	11	219
(viii) Oriiginal Forecast PI	1.0											
(x) SES term	40											

Cherry Valley (Prince Edward County) Community Expansion Project

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

		Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Total
(vi) Forecast Customer Attachments (#/yr)		41	44	24	11	11	5	4	4	4	4	152
(viii) Oriiginal Forecast PI	1.0											
(x) SES term	40											

Red Rock First Nation Community Expansion Project

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

		Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Total
(vi) Forecast Customer Attachments (#/yr)		21	20	13	7	6	2	2	2	2	2	77
(viii) Oriiginal Forecast PI	1.0											
(x) SES term	40											

Severn (Washago) Community Expansion Project

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

		Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Total
(vi) Forecast Customer Attachments (#/yr)		209	182	113	56	55	22	22	22	21	21	723
(viii) Oriiginal Forecast PI	1.0											
(x) SES term	40											

St. Charles Community Expansion Project

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

		Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Total
(vi) Forecast Customer Attachments (#/yr)		44	46	24	14	14	4	4	4	4	4	162
(viii) Oriiginal Forecast PI	1.0											
(x) SES term	40											

Tweed Community Expansion Project

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

Bobcaygeon Community Expansion Project

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

Caledon (Humber Station) Community Expansion Project

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

Chute-a-Blondeau Community Expansion Project

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

East Gwillimbury (North and East) Community Expansion Project

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

Glendale Subdivision Community Expansion Project

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

Lanark and Balderson Community Expansion Project

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

Merrickville-Wolford Community Expansion Project

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

Sandford Community Expansion Project

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

APPENDIX B

Methodology and Assumptions for

An Economic Evaluation

Last Revised October 21, 2009

APPENDIX B - METHODOLOGY AND ASSUMPTIONS FOR AN OFFER TO CONNECT ECONOMIC EVALUATION

B.1 COMMON ELEMENTS OF THE DISCOUNTED CASH FLOW MODEL

To achieve consistent business principles for the development of the elements of an economic evaluation model, the following parameters for the approach are to be followed by all distributors.

The discounted cash flow (DCF) calculation for individual projects will be based on a set of common elements and related assumptions listed below.

Revenue Forecasting

The common elements for any project will be as follows:

(a) Total forecasted customer additions over the Customer Connection Horizon, by class as specified below;

(b) Customer Revenue Horizon as specified below;

(c) Estimate of average energy and demand per added customer (by project) which reflects the mix of customers to be added - for various classes of customers, this should be carried out by class;

(d) Customer additions, as reflected in the model for each year of the Customer Connection Horizon; and

(e) Rates from the approved rate schedules for the particular distributor reflecting the distribution (wires only) rates.

Capital Costs

Common elements will be as follows:

(a) An estimate of all capital costs directly associated with the expansion to allow forecast customer additions.

(b) For expansions to the distribution system, costs of the following elements, where applicable, should be included:
- distribution stations;
- distribution lines;
- distribution transformers;

- secondary busses;
- services; and
- land and land rights.

Note that the “Ownership Demarcation Point” as specified in the distributor’s Condition of Service would define the point of separation between a customers’ facilities and distributor’s facilities.

(c) Estimate of incremental overheads applicable to distribution system expansion.

(d) A per kilowatt enhancement cost estimate – the per kilowatt enhancement cost estimate shall be set annually and shall be based on a historical three to five year rolling average of actual enhancement costs incurred in system expansions.

(d.1) paragraph (d) shall cease to apply to a distributor as of the date on which the distributor’s rates are set based on a cost of service application for the first time following the 2010 rate year.

(e) For residential customers, the amount the cost of the basic connection referred to in section 3.1.4 of the Code.

(f) For non-residential customers, if the distributor has chosen to recover the non-residential basic connection charge as part of its revenue requirement, a description of, and the amount for, the connection charges referred to in section 3.1.5 of the Code that have been factored into the economic evaluation.

Expense Forecasting

Common elements will be as follows:

(a) Attributable incremental operating and maintenance expenditures - any incremental attributable costs directly associated with the addition of new customers to the system would be included in the operating and maintenance expenditures.

(b) Income and capital taxes based on tax rates underpinning the existing rate schedules.

(c) Municipal property taxes based on projected levels.

Specific Parameters/Assumptions

Specific parameters of the common elements include the following:

(a) A maximum customer connection horizon of five (5) years, calculated from the energization date of the facilities.[1]

(b) A maximum customer revenue horizon of twenty five (25) years, calculated from the in service date of the new customers.[2]

(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 to reflect 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. The same approach to discounting will be used for revenues and operating and maintenance expenditures.[3]

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[1] For customer connection periods of greater than 5 years an explanation of the extension of the period will be provided to the Board

[2] For example, that the revenue horizon for customers connected in year 1, is 25 years while for those connected in year 3, the revenue horizon is 22 years.

[3] For certain projects Capital Expenditures may be staged and can occur in any year of the five year Connection Horizon.

B.2 DISCOUNTED CASH FLOW (DCF) METHODOLOGY

Net Present Value ("NPV")	=	Present Value ("PV") of Operating Cash Flow + PV of CCA Tax Shield - PV of Capital
1. PV of Operating Cash Flow	=	P V of Net Operating Cash (before taxes) - P V of Taxes
a) PV of Net Operating Cash	=	PV of Net Operating Cash Discounted at the Company's discount rate for the customer revenue horizon. Mid-year discounting is applied. Incremental after tax weighted average cost of capital will be used in discounting.
Net (Wires) Operating Cash	=	(Annual(Wires) Revenues - Annual (Wires) O&M)
Annual (Wires) Revenue	=	Customer Additions * [Appropriate (Wires) Rates * Rate Determinant]
Annual (Wires) O&M	=	Customer Additions * Annual Marginal (Wires) O&M Cost/customer
b) PV of Taxes	=	PV of Municipal Taxes + PV of Capital Taxes + PV of Income Taxes (before Interest tax shield)
Annual Municipal Tax	=	Municipal Tax Rate * (Total Capital Cost)
Total Capital Cost	=	Distribution Capital Investment + Customer Related Investment + overheadsd at the project level
Annual Capital Taxes	=	(Capital Tax Rate) * (Closing Undepreciated Capital Cost Balance)
Annual Capital Tax	=	(Capital Tax Rate) * (Net Operating Cash - Annual Municipal Tax B Annual Capital Tax)

The Capital Tax Rate is a combination of the Provincial Capital Tax Rate and the Large Corporation Tax (Grossed up for income tax effect where appropriate).

Note: Above is discounted, using mid-year discounting, over the customer revenue horizon.

2. PV of Capital	=	P V of Total Annual Capital Expenditures

a) PV of Total Annual Capital Expenditures

Total Annual Capital Expenditures over the customer's revenue horizon discounted to time zero

Total Annual Capital Expenditure	=	(for New Facilities and/or Reinforcement Investments + Customer Specific Capital + Overheads at the project level). This applies for implicated system elements at the utility side of the “Ownership Demarcation Line”.

Note: Above is discounted to the beginning of year one over the customer addition horizon

3. PV of CCA Tax Shield

P V of the CCA Tax Shield on [Total Annual Capital]

The PV of the perpetual tax shield may be calculated as:

PV at time zero of: $\dfrac{\text{[(Income tax Rate) * (CCA Rate) * Annual Total Capital]}}{\text{(CCA Rate + Discount Rate)}}$

or,

Calculated annually and present valued in the PV of Taxes calculation.

Note: An adjustment is added to account for the ½ year CCA rule.

4. Discount Rate

PV is calculated with an incremental, after-tax discount rate.

ENBRIDGE GAS INC.

Answer to Undertaking from
Environmental Defence (ED)

Undertaking

Tr: 81

To advise on what Enbridge's position is on what the requirements are under EBO-188, as it reflects to customer attachment and revenue horizon.

Response:

The Company's harmonized customer connection policies as proposed in this Application are designed in such a manner as to be compliant with the OEB's Report of the Board Guidelines for Assessing and Reporting on Natural Gas System Expansion in Ontario (E.B.O 188).[1]

E.B.O 188 sets out requirements for the common analysis of financial feasibility, including the structure of system expansion portfolios and the methods for conducting financial feasibility analyses at both the individual project level and the portfolio level. E.B.O 188 standardizes the elements to be used in the discounted cash flow (DCF) analysis and establishes the parameters for the costs and revenues that are the inputs to that analysis.

In the Final Report of the Board for E.B.O 188, the customer attachment and revenue horizons are referred to as maximums, however, Appendix B sets out specific horizons to be used by gas distributors in their DCF analysis (please see Section 2.2 of Appendix B). At this time, the Company believes it is appropriate to continue to use the specific parameters set out by the OEB, subject to project-specific circumstances where a shorter time horizon may be warranted to reflect the expected lifecycle of a project.

Question:

Pursuant to Enbridge Gas's letter dated April 11, 2023, in relation to Motions Day, Enbridge Gas agreed to provide a response to the following question posed on Day 5 of the Technical Conference, TC Tr. Vol. 5 79:

[1] Final Report to the Board. January 30, 1998.
https://www.oeb.ca/oeb/_Documents/Decisions/EBO%20188%20Decision.pdf

"on a best-efforts basis, stating any simplifying assumptions, to please estimate the test-year system-access spending if Enbridge were to apply a customer attachment forecast of five years and a maximum revenue horizon of 15 years."

Response: /u

The following response has been updated to reflect the Capital Update provided at Exhibit 2, Tab 5, Schedule 4, filed on June 16, 2023.

An estimate of system access spending for each year for the period of 2024 to 2028 assuming a revenue horizon of 15 years is provided in Table 1.

A scenario assuming an attachment horizon of five years for all projects is not possible as test-year customer forecasts on a year-by-year basis are not available at the individual project level necessary for such a calculation. Please note, though, that the vast majority of customer attachment projects are new build subdivisions, which typically entail an attachment period of three to five years, and many other projects are infill projects, which predominantly employ a single year attachment period.

Item 1) Customer Connections represents the amount of capital investment that can be supported by 15-years of net revenues, generated by the customer forecast to be added to the distribution system in each respective year. Please see the updated Exhibit I.2.6-ED-94 for an updated view of the customer connections forecast. Items 2) to 7) are the forecast costs for that year associated with each respective line item.

Table 1

$ Million	2024	2025	2026	2027	2028	Total	
1) Customer Connections	146.3	144.4	153.0	154.5	158.8	756.9	/u
2) DP Relocations	41.9	44.1	44.5	45.7	58.8	235.0	/u
3) DS - CNG	3.5	1.4	1.0	1.1	1.1	8.1	/u
4) GTH - Hydrogen Blending	9.8	11.3	3.3	-	-	24.3	/u
5) TPS - Growth	7.0	74.7	139.9	221.4	180.0	623.0	/u

6) UTIL - Meters Growth	16.9	17.3	18.9	19.7	12.7	85.4	/u
7) EA Fixed - Growth	38.2	39.2	40.2	41.3	23.2	182.1	/u
8) Community Expansion	11.2	19.6	20.5	21.5	7.3	80.1	/u
9) Total	274.8	351.9	421.2	505.0	441.9	1,994.9	/u

Note Table 1 also assumes indirect O&M overheads are re-allocated across projects as a result of the decrease in customer connections capital spend. System access spend decreases by approximately $500 million over the 2024 to 2028 period.