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Reply to the Attention of	Laura Brazil
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Our File No.	231915
Date	April 22, 2016

RESS

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

Attention: Kristen Walli
Board Secretary
boardsec@ontarioenergyboard.ca

Dear Ms. Walli:

Re: CPA Responses to Interrogatories
EB-2016-0004

We are counsel to the Canadian Propane Association (the "**CPA**"), an intervenor in this proceeding.

Enclosed are CPA's responses to the interrogatories of Energy Probe Research Foundation in accordance with the Decision and Procedural Order No. 2, issued by the Board on March 9, 2016.

Yours truly,

Laura Brazil

/cs
Attach.
cc by email: Intervenors in EB-2016-0004

ONTARIO ENERGY BOARD

Application under the Ontario Energy Board's own motion to consider potential alternative approaches to recover costs of expanding natural gas service to communities that are not currently served

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CANADIAN PROPANE ASSOCIATION RESPONSES TO INTERROGATORIES OF ENERGY PROBE RESEARCH FOUNDATION

CANADIAN PROPANE ASSOCIATION (CPA) RESPONSES TO INTERROGATORIES OF ENERGY PROBE RESEARCH FOUNDATION (ENERGY PROBE)

Interrogatory 1

Reference

CPA Evidence page 6

Preamble

The Legislature has never given the Board jurisdiction to subsidize natural gas expansion. When the Legislature chose to grant the Board jurisdiction to subsidize electricity expansion, it amended the OEB Act to add section 79. Section 79 expressly grants the Board the authority to require existing customers to subsidize rural or remote electricity customers: "All consumers are required to contribute towards the amount of any compensation required under subsection (3) in accordance with the regulations." However, the Legislature has chosen not to make any such amendment to the OEB Act for natural gas subsidization.

Please provide a list and precise of any and all legal cases that have confirmed the CPA position that the Board has no mandate authority to impose a subsidy for Community Expansion.

CPA Response

EB-2015-0179 is the first case that CPA is aware of in which the Board has considered financing the uneconomic expansion of the natural gas system by forcing existing customers to subsidize new customers. See also Exhibit S2.CPA.BoardStaff.1.

Interrogatory 2

Reference

CPA Evidence page 8

Preamble

The Board should not depart from the principles set out in EBO-188. However, if it chooses to revert to considering broader costs and benefits as suggested in EBO-134, the Board must consider both the benefits and the costs of expanding natural gas service to areas that are already serviced by other fuel suppliers.

a) Has CPA considered if the EBO 188 Guidelines should be modified to include some form of Stage 2 and or Stage 3 economic cost/benefit analyses?

b) If so, provide the framework, assumptions and weighting that CPA believes should be used with reference to EBO 134 and proposals made by Union and Enbridge.

c) How should the Board address the incremental costs/benefits to communities already serviced by other fuel suppliers?

CPA Response

Please see the response to 3(c) and (d) below. As explained therein, the social benefits should not be directly considered by the OEB at all, as they are already incorporated in the amount of any Government funding (government re-allocation of taxpayer dollars being done on the basis of perceived societal benefits and social objectives). The amount of such Government funding should form part of the Board's EBO 188 economic analysis and the determination of profitability index, thereby already indirectly causing the social benefits to be factored into the Board's assessment (in other words, the amount of Government funding is as quantification of the social benefit).

However, if the OEB elects instead to use Stage 2 or Stage 3 types of tests directly (which CPA believes would be duplicative if the Board also considers Government funding as part of its economic analysis), then they should be designed to include ALL of the measurable societal costs and benefits that arise; and the OEB should rely on independent experts to determine the appropriateness of the benefits and costs that are included by the Applicant.

Interrogatory 3

Reference

Exhibit 3, Tab 3, Evidence of Charles Budd, Navigant

Preamble

By relying upon the principles of basing rates on costs and no harm to ratepayers, the OEB is performing the role of facilitating rational natural gas expansion and ensuring that there is no undue cross-subsidization between existing and new customers. The OEB should continue to apply the principles and policies of EBO 188 and EBO 134. Departure from the economic testing prescribed in EBO 188 and EBO 134 should result from government policy as opposed to OEB discretion.

a) Please provide comments on the no harm principle and provide relevant regulatory precedent and examples.

b) Given the Government's Letter of Direction to the Board please indicate how should departures from the current EBO 188 Guidelines be addressed? Comment specifically regarding amendments vs exceptions.

c) If EBO 134 Stage 2 and Stage 3 analyses were to be considered what would the framework and analyses.

d) In addition what weighting should be applied to the Stage 2 and Stage 3 analyses in a Community Expansion context?

CPA Response

3 (a) In the Final Report of the Ontario Energy Board in E.B.O. 188, the Board stated that it "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." This is in effect a no-harm test, where harm is defined with respect to the price the consumers pay for natural gas service. The Final Report in E.B.O. 188 (January 30,1998) is attached at **Tab "1"** of these responses.

The Board also applies a no harm test when it comes to evaluating electricity distributor and transmitter consolidation. "The "no harm" test assesses whether the proposed transaction will have an adverse effect on the attainment of the OEB's statutory objectives. While the OEB has broad statutory objectives, in applying the "no harm" test, the OEB has primarily focused its review on impacts of the proposed transaction on price and quality of service to customers, and the cost effectiveness, economic efficiency and financial viability of the electricity distribution sector." Please see the Ontario Energy Board, Handbook to Electricity Distributor and Transmitter Consolidations (January 19, 2016), which is attached at **Tab "2"** of these responses.

3 (b) The "Government's Letter of Direction" referred to by Energy Probe (described herein as the "**Minister's Letter**") was not in fact a letter of direction or a "Directive" as defined in the *Ontario Energy Board Act, 1998*. In fact, the Minister's Letter stated that its purpose was:

> "to encourage the Board to continue to move forward on a timely basis on its plans to examine opportunities to facilitate access to natural gas services to more communities…"

There was no directive or direction; just "encouragement". There was no discussion of proceeding to construct expansion projects; just "<u>plans</u> to <u>examine</u> <u>opportunities</u> to <u>facilitate</u>…". There was no contemplation at all of uneconomic projects; the Minister's Letter only mentioned an interest in expansion to "more communities". Not once did it indicate a desire to promote uneconomic projects.

Because the Minister's Letter did not imply or even hint at uneconomic projects, it therefore, understandably, did not mention departures from EBO 188. Nothing in the Minister's Letter mentions EBO 188 or even refers to any of principles of EBO 188, so there was certainly no direction to depart from EBO 188 or even any direction to consider departures from EBO 188.

The idea that the Minister was interested in uneconomic projects, and the concept of departing from EBO 188, were developed by the Board alone in its letter to stakeholders the following day (the "**Board's Letter**"). The CPA disagrees that any departure from EBO 188 is warranted.

Before concluding that the Board ought to depart from EBO 188, the Board should consider several issues. First, the Board ought to consider, with input, whether gas expansion for the sake of gas expansion is in the public interest. There appears to be a presumption that natural gas is the superior source of energy - this at the same time as the government has declared that fossil fuels (of which natural gas is one) are a burden on society and should be phased out. Regardless of the Minister's "encouragement", absent a Directive, the Board has a duty to determine for itself, independent from government, what is in the public interest. That examination ought to begin with an assessment of whether it is in the public interest to spend hundreds of millions of dollars on long-term capital infrastructure for the delivery of a fossil fuel which could become obsolete very soon after such infrastructure is installed.

Second, if the Board finds, after a fulsome hearing, that expansion of the natural gas system is in the public interest, then the Board should consider, with input, whether uneconomic expansions should be considered, or just economic expansions.

Third, if the Board determines, after considering broad input, that uneconomic projects and economic projects are equally in the public interest ,then the Board should consider what variety of mechanisms exist to achieve such expansions, including market-based mechanisms and government-funded mechanisms. Before jumping to the conclusion that it is necessary to depart from EBO 188, the Board should consider whether there are mechanisms available within the existing framework that do not require a departure from EBO 188. The CPA believes there are, and that departures from EBO 188 are not necessary – that is, assuming gas expansion has been determined to be in the public interest in the first place, and that uneconomic expansion projects have been determined to be in the public interest in the second instance.

The CPA is pleased that the Board has launched the present Generic Hearing. However, the Board should not interpret the Minister's Letter as definitively answering any or all of the above questions, and the Board should ensure that it duly considers all three of the above questions and seeks appropriate input on all three matters.

3 (c) & (d)

No weighting should be applied to the Stage 2 and Stage 3 analyses by the Board. See our response to Exhibit S2.CPA.EnergyProbe.2 for further explanation. If the Stage 2 and Stage 3 analyses are to be considered and applied, they should apply to the Government's decision on how to allocate its Natural Gas Access Loans, or its Natural Gas Economic Development Grants, or other government subsidy programs (which analysis the Government may delegate to the Board if it wishes). Those projects which merit and receive such public funding following a Stage 2 and Stage 3 analyses should be able to satisfy the EBO 188 profitability tests if those grants are factored in to the equation. If they still fail the OEB's PI test, it is because not enough Government funding was awarded, which is turn is presumably because the analyses determined that the public benefit of the projects was not high enough to merit further public investment. If the public benefit of the projects was not high enough to merit further public investment. If the public benefit of a project is so high that it simply must proceed, then the Government will allocate enough money to allow it to break even. In other words, if the social gains of the project are greater than the economic losses, the Government will fund the losses (because the net public benefit – public gain minus public cost – will be positive, making this a good investment of taxpayer dollars). In such a case, when considering all of the economics including the public funding, the project would have a PI of 1.0 and would pass the current EBO 188 tests. If the social gains are not as great as the economic losses, then the Government likely won't fund it, because the gains are not worth the cost. In such a case, the project would still not achieve a PI of 1.0 and would not proceed under EBO 188; nor should it if the social benefits are less than the economic costs.

If such Stage 2 and Stage 3 factors (a.k.a. social benefits) are used by Government in determining what government subsidies to award, as suggested above, then those factors will be incorporated into the OEB's decision simply by including the amount of the Government funding in the Board's EBO 188 profitability index analysis. The amount of the Government funding essentially represents or quantifies the Stage 2 and Stage 3 social benefit tests. So they are indirectly factored in by just having the Board consider the Government funding as part of its EBO 188 economic analysis.

Interrogatory 4

Reference

Exhibit 3, Tab3, Evidence of Charles Budd, Navigant

Preamble

The OEB should incorporate the Ontario Government's recently announced loan and grant programs into the economic feasibility analysis for expansion. To the extent that such loans or grants reduce or offset investment or costs that would otherwise be borne by new or existing ratepayers, the impacts should be reflected in the PI analyses.

Using the current EBO 188 Economic Analysis framework, (set out in Appendix B of the Board Decision) please provide an illustration how Government Grants/Loans could be incorporated in the DCF analysis. List all relevant assumptions

CPA Response

The value of government grants and loans should be treated as a reduction in the capital cost of the project under Stage 1 of the financial feasibility test. The assets purchased with the government grants and loans should be treated as contributed capital for the purpose of ratemaking.

Was preliminary page 1 1
E.B.O. 188

IN THE MATTER OF the *Ontario Energy Board Act*[12JF7-0:1], R.S.O. 1990, c. O.13; 2

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. 3

BEFORE: G.A. Dominy 4
Presiding Member
R.M.R. Higgin
Member
J.B. Simon
Member

FINAL REPORT OF THE BOARD 5

January 30, 1998 6

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1. THE PROCEEDING Was page 1 13

1.1 THE BACKGROUND 14

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. 15

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. 16

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. 17

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"). 18

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. Was page 2 19

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: 20

1.1 *Should financial feasibility be the only determinant for expansion or should it include, apart from security of supply and safety:* 21

(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, 22
1996.

1.1.8 An Interim Report[12JM1-0:1] of the Board ("Interim Report") was issued on August 15, 1996. 23
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").

Was page 3 24

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 submis- 25
sion of:

- an ADR Agreement filed with the Board on March 14, 1997, subscribed to by the utilities 26
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 Agree- 27
ment and their Rectification" dated April 1, 1997 ("Dissent Document");

- letters of comment from various parties on the ADR Agreement and Dissent Document; 28
and

- responses (dated July 25, 1997) to a set of Board clarification questions to the utilities. 29

1.1.11 The parties concurring with the ADR Agreement and those substantially supporting the Dissent 30
Document are listed in Appendix A[241].

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[247] to this Report. 31

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. 32

1.1.14 The Board's comments and findings are structured as: Was page 4 33

- The Portfolio Approach 34
- Common Methods for Financial Feasibility Analysis 35
- Customer Connection and Contribution Policies 36
- Environmental Planning Requirements for System Expansion 37
- Monitoring and Reporting Requirements 38

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. 39

1.2 INTERVENTIONS 40

1.2.1 The following parties intervened in the proceeding: 41

- Canadian Association of Energy Service Companies 42
- City of Kitchener 43
- Consumers' Association of Canada 44
- Energy Probe 45
- Federation of Northern Ontario Municipalities 46
- Green Energy Coalition 47

- Grenville-Wood 48
- The Heating, Ventilation, Air Conditioning Contractors Coalition Inc. 49
- Industrial Gas Users Association 50
- Municipal Electric Association 51
- Natural Resource Gas Limited 52
- Northwestern Ontario Municipal Association 53
- Ontario Coalition Against Poverty 54
- Ontario Federation of Agriculture 55
- Ontario Hydro 56
- Ontario Native Alliance 57
- Ontario Pipeline Landowners' Association 58
- Ottawa-Carleton Gas Purchase Consortium 59
- Pollution Probe 60
- Power Workers' Union 61
- TransAlta Energy Corporation 62
- TransCanada PipeLines Limited 63
- Woodland Hills Community Inc. Was page 5 64

LATE INTERVENTIONS 65

- The British Columbia Ministry of Energy, Mines and Petroleum Resources 66

2. THE PORTFOLIO APPROACH Was page 7 72

2.1 INTERIM REPORT CONCLUSIONS 73

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.* 74

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.* 75

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.* 76

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.* 77

Was page 8 78

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 or <u>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* 79

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.* 80

2.2 POSITIONS OF THE PARTIES 81

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). 82

Was page 9

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. 83

2.2.3 The Dissent Document listed three concerns with the Investment Portfolio proposed in the ADR Agreement: 84

i. service lines off existing mains are included; 85

ii. security of supply projects are not included; and 86

iii. reinforcement costs have been normalized rather than using forecast actual costs. 87

2.3 BOARD'S COMMENTS AND FINDINGS 88

Investment Portfolio 89

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 90 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).

91

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.

92

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.

Was page 10 93

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.

94

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.

95

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[214]).

96

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.

Was page 11 97

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.

98

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 associ- 99
ated 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 100

2.3.11 The Board also accepts the ADR Agreement proposal to maintain a Rolling Project Portfolio. The 101
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).

Was page 12

2.3.12 As noted above the Board finds the proposed treatment for reinforcement costs to be included in 102
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 manage- 103
ment 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 rev- 104
enues 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 Was page 13 105

3.1 INTERIM REPORT CONCLUSIONS 106

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.* 107

3.2 POSITIONS OF THE PARTIES 108

3.2.1 The ADR Agreement set the following parameters for the DCF analysis: 109

(a) Customer Attachment Horizon 110

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. 111

(b) Customer Revenue Horizon 112

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. 113

(c) Discount Rate Was page 14 114

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. 115

(d) Discounting 116

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 117 throughout the year will be mid-year discounted, as will revenue, gas related costs, and operating and maintenance expenditures.

(e) Operating and Maintenance Expenditures 118

The incremental costs directly associated with the attachment of new customers to the system will be included in the operating and maintenance expenditures. 119

(f) Gas Costs 120

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. 121

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. 122

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. 123

3.2.4 The Dissent Document proposed: Was page 15 124

- a customer attachment horizon no longer than 5 years (unless there is a specific contract); 125
- 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; 126
- customer use volumes representing the best estimates of the gas consumption for new customers; and 127
- the inclusion of incremental costs associated with gas storage and TransCanada PipeLines Limited transmission. 128

3.3 BOARD'S COMMENTS AND FINDINGS 129

3.3.1 The Board notes that the utilities have undertaken to apply consistent business principles for the 130
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 131
and adopts this as part of the Guidelines in Appendix B[247].

3.3.3 The Board is concerned that a customer revenue horizon of 40 years will encourage inclusion of 132
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 133
costs for the transportation and storage of gas will add unnecessary complexity to the DCF calculations for distribution system expansion projects.

Was page 16

3.3.5 The Board finds however that the methodology should include a standard test or measure to assess 134
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 pro- 135
posed 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[247].

4. CUSTOMER CONNECTION AND CONTRIBUTION POLICIES Was page 17 136

4.1 INTERIM REPORT CONCLUSIONS 137

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.* 138

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.* 139

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.* 140

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.* 141

4.2 POSITIONS OF THE PARTIES Was page 18 142

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. 143

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. 144

4.2.3 The ADR Agreement did not propose a definition to be used in determining when a facility is to be considered "dedicated". 145

4.2.4 The Dissent Document does not address the issue of customer contribution policies. 146

4.3 BOARD'S COMMENTS AND FINDINGS 147

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. 148

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. 149

Was page 19 150

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 151

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. 152

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. 153

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. 154

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5. ENVIRONMENTAL PLANNING REQUIREMENTS FOR SYSTEM EXPANSION Was page 21 156

5.1 INTERIM REPORT CONCLUSIONS 157

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.* 158

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[12JF6-0:1] ("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.* 159

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.* 160

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.* Was page 22 161

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.* 162

5.2 POSITIONS OF THE PARTIES 163

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 infor- 164 mation 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 165
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 miti- 166
gating 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 167
Board's Interim Report because:

Was page 23

i. the utilities have not yet developed common guidelines on how to conduct and document 168
the evaluation of their route selection; and

ii. according to the ADR Agreement, the utilities can select a route that will cause significant 169
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 170
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 171
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 172

5.3.1 The Board notes that a move to a portfolio planning and management approach may result in less 173
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. 174

Was page 24

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. 175

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. 176

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. 177

Was page 25

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. 178

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. 179

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. 180

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6. MONITORING AND REPORTING REQUIREMENTS Was page 27 182

6.1 INTERIM REPORT CONCLUSIONS 183

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.* 184

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:* 185

- *ratepayers are protected from financially risky decisions on expansion by the utilities;* 186
- *the utilities make decisions on which projects should proceed in an even-handed manner;* 187
- *the cumulative impact on rates is not undue in any given year;* 188
- *the continued expansion of natural gas service is in the overall public interest; and* 189
- *the economic inefficiencies implicit in including projects with negative P.I.s do not outweigh the public interest benefits of the portfolio approach.* 190

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.* 191

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.* Was page 28 192

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* 193 *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.* 194

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.* 195

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.* 196

6.2 POSITIONS OF THE PARTIES 197

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. 198

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. 199

Was page 29

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: 200

- 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; 201

- 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 202

- 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. 203

6.2.4 The parties to the Dissent Document further submitted that the ADR Agreement fell short because: 204

- there is no commitment to provide a comparison of actual and forecast volumes; 205

- there is no commitment to provide a comparison of actual and forecast capital expenditures for the Investment Portfolio; and 206

- 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. 207

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. 208

6.3 BOARD'S COMMENTS AND FINDINGS Was page 30 209

6.3.1 The Board believes that the principles outlined in the Interim Report should form the basis of the monitoring and reporting requirements. 210

<u>Rate Case Review</u> 211

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. 212

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. 213

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. 214

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: 215

- impact of the Investment Portfolio cash flow on the test year revenue deficiency; and Was page 31 216

- the ratio of incremental revenues to costs in the test year and subsequent three years. 217

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. 218

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. 219

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. 220

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. 221

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. Was page 32 222

Ongoing Monitoring and Reporting 223

6.3.11 The Board notes that the primary purposes of the Guidelines in Appendix B[247] 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. 224

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 225 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. 226

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. 227

Was page 33

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. 228

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. 229

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7. COMPLETION OF THE PROCEEDING AND COSTS

232

7.1 COMPLETION OF THE PROCEEDING

233

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[247] of this Report.

234

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.

235

7.2 COSTS

236

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.

237

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.

Was page 36 238

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.

239

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.

G.A. Dominy
Vice Chair and Presiding Member

R.M.R. Higgin
Member

J. B. Simon
Member

APPENDIX A Was Appendix, preliminary page 1 241

Parties Concurring with the ADR Agreement 242

Board Staff 243
City of Kitchener
The Consumers' Gas Company Ltd.
Consumers' Association of Canada
Federation of Northern Ontario Municipalities
Northwestern Ontario Municipal Association
Ontario Federation of Agriculture*
Ontario Pipeline Landowners Association*
Ontario Coalition Against Poverty
Union Gas Limited and Centra Gas Ontario Inc.*

Parties Substantially Supporting the Dissent Document 244

Canadian Industry Program for Energy Conservation* 245
Canadian Association of Energy Service Companies
Energy Probe
Green Energy Coalition*
Industrial Gas Users Association*
Heating, Ventilation, Air Conditioning Contractors Coalition Inc.
Ontario Native Alliance
Pollution Probe

* Letter of Comment Received 246

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APPENDIXB ONTARIO ENERGY BOARD GUIDELINES FOR ASSESSING AND REPORTING ON NATURAL GAS SYSTEM EXPANSION IN ONTARIO 247

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CONTENTS 249

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I. OVERVIEW - PURPOSE AND OBJECTIVE OF THE GUIDELINES 258

The Ontario Energy Board ("OEB", "Board") Guidelines for Assessing and Reporting on Natural Gas System Expansion In Ontario ("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.

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1. SYSTEM EXPANSION PORTFOLIOS 271

1.1 Investment Portfolio 272

Each of the utilities will group into a portfolio (the "Investment Portfolio") the costs and revenues 273
associated with all new distribution customers who are forecast to attach in a particular test year (including new customers attaching to existing mains). The Investment Portfolio is to include a forecast of normalized system reinforcement costs.

The Investment Portfolio 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 276
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.

The utilities will calculate monthly the cumulative result of project-specific DCF analyses from the 277
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.

2. STANDARD TEST FOR FINANCIAL FEASIBILITY 278

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

2.1 DCF Calculation and Common Elements 280

The DCF calculation for a Portfolio will be based on a set of common elements. For revenue forecasting, 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

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 315
portfolio PI;

(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 320
Rolling Project Portfolio;

(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 322
customer related data.

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 Contribution in Aid Policies. 343

The criteria for contributions in aid of construction for service lines and mains will apply to all 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. 344

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

- Requirements for payment for all, or part, of a customer 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. 346
- Requirements for contributions in aid of construction for connection of individual customers, subdivisions or communities requiring main extensions that would not otherwise be included in the Investment or Rolling Project Portfolios. 347
- Requirements for contributions in aid of construction for expansion projects dominated by one or more large volume customers. 348

5. ENVIRONMENTAL REQUIREMENTS FOR DISTRIBUTION FOR SYSTEM EXPANSION PROJECTS 349

The planning principles described in the Board's "Environmental Guidelines for the Location, 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. 350

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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. 351

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

353

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

354

6. DOCUMENTATION, RECORD KEEPING AND REPORTING

355

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.

356

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.

357

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.

358

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

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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*

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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. <u>PV of Capital</u> = *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)*

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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. <u>PV of CCA Tax Shield</u>

PV 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 : $\dfrac{[(\text{Income Tax Rate}) * (\text{CCA Rate}) * \text{Annual Total Capital}]}{(\text{CCA Rate} + \text{Discount Rate})}$

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.

Ontario Energy Board

Commission de l'énergie de l'Ontario

Handbook to Electricity Distributor and Transmitter Consolidations

January 19, 2016

Table of Contents

1. Introduction

The Ontario Energy Board (OEB) has developed this Handbook to provide guidance to applicants and stakeholders on applications to the OEB for approval of distributor and transmitter consolidations and subsequent rate applications. This Handbook uses the term consolidation to be inclusive of mergers, acquisitions, amalgamations and divestitures (MAADs).

The Commission on the Reform of Ontario's Public Services, the Distribution Sector Review Panel and the Premiers Advisory Council on Government Assets have all recommended a reduction in the number of local distribution companies in Ontario and have endorsed consolidation. According to these reports, consolidation can increase efficiency in the electricity distribution sector through the creation of economies of scale and/or contiguity. Consolidation permits a larger scale of operation with the result that customers can be served at a lower per customer cost. Consolidations that eliminate geographical boundaries between distribution areas result in a more efficient distribution system.

Consolidation also enables distributors to address challenges in an evolving electricity industry. This includes new technology requirements to meet customer expectations, changing dynamics in the electricity sector with the growth of distributed energy resources and to undertake asset renewal. Distributors will need considerable additional investment to meet these challenges and consolidation generally offers larger utilities better access to capital markets, with lower financing costs.

Distributors are also expected to meet public policy goals relating to electricity conservation and demand management, implementation of a smart grid, and promotion of the use and generation of electricity from renewable energy sources. Delivering on these public policy goals will require innovation and internal capabilities that may be more cost effective for larger distributors to develop or retain.

The OEB recognizes that there is a growing interest in and support for consolidation. The OEB has a statutory obligation to review and approve consolidation transactions where they are in the public interest. In discharging its mandate, the OEB is committed to reducing regulatory barriers to consolidation. In order to facilitate both a thorough and timely review of requests for approval of transactions, in this Handbook the OEB provides guidance on the process for review of an application, the information the OEB expects to receive in support, and the approach it will take in assessing the merits of the consolidation in meeting the public interest.

Recent OEB policies and decisions on consolidation applications have already established a number of principles to create a more predictable regulatory environment for applicants. This Handbook will provide further clarity to applicants, investors, shareholders, and other stakeholders. The Handbook also discusses the rate-making policies associated with consolidations and sets out the timing of when such matters will be considered by the OEB.

While the Handbook is applicable to both electricity distributors and transmitters, most of the OEB's policies and prior OEB decisions have related to distributors. Transmitters should consider the intent of the Handbook and make appropriate modifications as needed to reflect differences in transmitter consolidations.

2. The OEB Authority and Review Process

This section describes the OEB's legal authority in approving consolidation applications and clarifies how the OEB reviews these applications.

The OEB legislative authority

OEB approval is required for consolidation transactions described under section 86 of the *Ontario Energy Board Act, 1998* (OEB Act). (For ease of reference, Section 86 is reproduced in Schedule 1 of this Handbook.) Briefly, these transactions are as follows:

- A distributor or transmitter sells or otherwise disposes of its distribution or transmission system as an entirety or substantially as an entirety to another distributor
- A distributor or transmitter sells a part of a distribution or transmission system that is necessary in serving the public
- A distributor or transmitter amalgamates with another distributor or transmitter
- A person acquires voting securities of a transmitter or distributor or acquires control of a corporation with voting shares

Section 86(2) relating to voting securities does not, however, apply to the acquisition or sale of shares in Hydro One, a company created by the Crown under section 50(1) of the *Electricity Act, 1998*, which is explicitly exempt under section 86(2.1) from the conditions stipulated in section 86(2).

The Application Review Process

This Handbook applies specifically to applications under sections 86(1)(a) and (c) and sections 86(2)(a) and (b) of the OEB Act, which are processed through the OEB's adjudicative review process. Sections 86(1)(a) and (c) of the OEB Act relate to asset sales and amalgamations. Section 86(2) of the OEB Act relates to voting securities. To assist applicants, the OEB has developed Filing Requirements in Schedule 2 of this Handbook which set out the information that needs to be provided in an application. These Filing Requirements replace the form entitled **Application Form for Applications under Section 86 of the OEB Act** that was previously posted on the OEB's website.

Applications filed under section 86(1)(b) of the OEB Act are generally processed through the OEB's administrative review process, typically without a hearing. These applications generally include the sale of smaller scale distribution or transmission assets from one distributor or transmitter to another, or to a large consumer who is served by the same assets. For these applications, applicants may continue using the form entitled **Application Form for Applications under Section 86(1)(b) of the OEB Act** that is posted on the OEB's website, (http://www.ontarioenergyboard.ca/OEB/Industry/Rules+and+Requirements/Rules+Codes+Guidelines+and+Forms#maad).

The OEB may elect to process a section 86(1)(b) application under its adjudicative review process if the OEB considers that certain aspects of an application could affect service to the public and/or have a material effect on rates. This will be determined once the application is filed with the OEB. In those circumstances, this Handbook will be applicable. Applicants who are of the view that their transaction is material should use this Handbook to inform their application.

3. The OEB Test

The No Harm Test

In reviewing an application by a distributor for approval of a consolidation transaction, the OEB has, and will continue, to apply its "no harm test". The "no harm" test was first established by the OEB in 2005 through an adjudicative proceeding (the Combined Proceeding).[1]

The “no harm” test considers whether the proposed transaction will have an adverse effect on the attainment of the OEB’s statutory objectives, as set out in section 1 of the OEB Act. The OEB will consider whether the “no harm” test is satisfied based on an assessment of the cumulative effect of the transaction on the attainment of its statutory objectives. If the proposed transaction has a positive or neutral effect on the attainment of these objectives, the OEB will approve the application.

The OEB’s objectives under section 1 of the OEB Act are:

1. To protect the interests of consumers with respect to prices and the adequacy, reliability and quality of electricity service.
    1.1 To promote the education of consumers.
2. To promote economic efficiency and cost effectiveness in the generation, transmission, distribution, sale and demand management of electricity and to facilitate the maintenance of a financially viable electricity industry.
3. To promote electricity conservation and demand management in a manner consistent with the policies of the Government of Ontario, including having regard to the consumer’s economic circumstances.
4. To facilitate the implementation of a smart grid in Ontario.
5. To promote the use and generation of electricity from renewable energy sources in a manner consistent with the policies of the Government of Ontario, including the timely expansion or reinforcement of transmission systems and distribution systems to accommodate the connection of renewable energy generation facilities.

4. The OEB Assessment of the Application

This section sets out how the OEB applies the “no harm” test within the context of the performance-based regulatory framework, the Renewed Regulatory Framework for Electricity Distributors[2] (RRFE). This framework was established by the OEB in 2012 to

[1] Combined Proceeding Decision - OEB File No. RP-2005-0018/EB-2005-0234/EB-2005-0254/EB-2005-0257

[2] Report of the Board: Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach

ensure that regulated distribution companies operate efficiently, cost effectively and deliver outcomes valued by its customers.

The Renewed Regulatory Framework

Ongoing performance improvement and performance monitoring are underlying principles of the RRFE. The OEB's oversight of utility performance relies on the establishment of performance standards to be met by distributors, ongoing reporting to the OEB by distributors, and ongoing monitoring of distributor achievement against these standards by the OEB.

An electricity distributor is required, as a condition of its licence, to provide information about its distribution business. Metrics are used by the OEB to assess a distributor's services, such as frequency of power outages, financial performance and costs per customer. The OEB uses this information to monitor an individual distributor's performance and to compare performance across the sector. The OEB also has a robust audit and compliance program to test the accuracy of reporting by distributors.

As part of the regulatory framework, distributors are expected to achieve certain outcomes that provide value for money for customers. One of these outcomes is operational effectiveness, which requires continuous improvement in productivity and cost performance by distributors and that utilities deliver on system reliability and quality objectives. The OEB uses processes to hold all utilities to a high standard of efficiency and effectiveness.

The OEB has a proactive performance monitoring framework that inherently protects electricity customers from harm related to service quality and reliability and has established the mechanisms to intervene if corrective action is warranted. The OEB will be informed by the metrics that are used to evaluate a distributor's performance in assessing a proposed consolidation transaction.

All of these measures are in place to ensure that distributors meet expectations regardless of their corporate structure or ownership. The OEB assesses applications for consolidation within the context of this regulatory framework.

The No Harm Test

The “no harm” test assesses whether the proposed transaction will have an adverse effect on the attainment of the OEB’s statutory objectives. While the OEB has broad statutory objectives, in applying the “no harm” test, the OEB has primarily focused its review on impacts of the proposed transaction on price and quality of service to customers, and the cost effectiveness, economic efficiency and financial viability of the electricity distribution sector. The OEB considers this to be an appropriate approach, given the performance-based regulatory framework under which all regulated distributors are required to operate and the OEB’s existing performance monitoring framework.

The OEB has implemented a number of instruments, such as codes and licences that ensure regulated utilities continue to meet their obligations with respect to the OEB’s statutory objectives relating to conservation and demand management, implementation of smart grid and the use and generation of electricity from renewable resources. With these tools and the ongoing performance monitoring previously discussed, the OEB is satisfied that the attainment of these objectives will not be adversely effected by a consolidation and the “no harm” test will be met following a consolidation. There is no need or merit in further detailed review as part of the OEB’s consideration of the consolidation transaction.

Scope of the Review

The factors that the OEB will consider in detail in reviewing a proposed transaction are as follows:

Objective 1 – Protect consumers with respect to price and the adequacy, reliability and quality of electricity service

Price

A simple comparison of current rates between consolidating distributors does not reveal the potential for lower cost service delivery. These entities may have dissimilar service territories, each with a different customer mix resulting in differing rate class structure characteristics. For these reasons, the OEB will assess the underlying cost structures of the consolidating utilities. As distribution rates are based on a distributor’s current and projected costs, it is important for the OEB to consider the impact of a transaction on the cost structure of consolidating entities both now and in the future, particularly if there appear to be significant differences in the size or demographics of consolidating distributors. A key expectation of the RRFE is continuous improvement in productivity and cost performance by distributors. The OEB's review of underlying cost structures supports the OEB's role in regulating price for the protection of consumers.

Consistent with recent decisions,[3] the OEB will not consider temporary rate decreases proposed by applicants, and other such temporary provisions, to be demonstrative of "no harm" as they are not supported by, or reflective of the underlying cost structures of the entities involved and may not be sustainable or beneficial in the long term. In reviewing a transaction the OEB must consider the long term effect of the consolidation on customers and the financial sustainability of the sector.

To demonstrate "no harm", applicants must show that there is a reasonable expectation based on underlying cost structures that the costs to serve acquired customers following a consolidation will be no higher than they otherwise would have been. While the rate implications to all customers will be considered, for an acquisition, the primary consideration will be the expected impact on customers of the acquired utility.

Adequacy, reliability and quality of electricity service

In considering the impact of a proposed transaction on the quality and reliability of electricity service, and whether the "no harm" test has been met, the OEB will be informed by the metrics provided by the distributor in its annual reporting to the OEB and published in its annual scorecard.

The OEB's *Report of the Board: Electricity Distribution Systems Reliability Measures and Expectations*, issued on August 25, 2015 sets out the OEB's expectations on the level of reliability performance by distributors. In the Report, the OEB noted that continuous improvement will be demonstrated by a distributor's ability to deliver improved reliability performance without an increase in costs, or to maintain the same level of performance at a reduced cost.

Under the OEB's regulatory framework, utilities are expected to deliver continuous improvement for both reliability and service quality performance to benefit customers. This continuous improvement is expected to continue after a consolidation and will continue to be monitored for the consolidated entity under the same established requirements.

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[3] Hydro One Inc./Norfolk Power Distribution Inc. – OEB File No. EB-2013-0196/EB-2013-0187/EB-2013-0198
Hydro One Inc./Haldimand County Hydro Inc. – OEB File No. EB-2014-0244

Objective 2 – Promote economic efficiency and cost effectiveness and to facilitate the maintenance of a financially viable electricity industry

The impact that the proposed transaction will have on economic efficiency and cost effectiveness (in the distribution or transmission of electricity) will be assessed based on the applicant's identification of the various aspects of utility operations where it expects sustained operational efficiencies, both quantitative and qualitative.

The impact of a proposed transaction on the acquiring utility's financial viability for an acquisition, or on the financial viability of the consolidated entity in the case of a merger will also be assessed. The OEB's primary considerations in this regard are:

- The effect of the purchase price, including any premium paid above the historic (book) value of the assets involved
- The financing of incremental costs (transaction and integration costs) to implement the consolidation transaction

In the Combined Proceeding decision, the OEB made it clear that the selling price of a utility is relevant only if the price paid is so high as to create a financial burden on the acquiring company. This remains the relevant test. While there may not be a premium involved with mergers, the OEB will nevertheless consider the financial viability of the newly consolidated entity.

Electricity distribution rates are currently based on a return on the historic value of the assets. If a premium has been paid above the historic value, this premium is not recoverable through distribution rates and no return can be earned on the premium. A shareholder may recover the premium over time through savings generated from efficiencies of the consolidated entity. In considering the appropriateness of purchase price or the quantum of the premium that has been offered, only the effect of the purchase price on the underlying cost structures and financial viability of the regulated utilities will be reviewed. Specifically, the OEB will test the financial ratios and borrowing capacity of the resulting entity, as the improvement in financial strength is one of the expected underlying benefits of consolidation.

Incremental transaction and integration costs are not generally recoverable through rates. Distributors have indicated that these costs are significant and that recovery of these costs can be a barrier to consolidation. To address distributors' concerns, the OEB issued a report on March 26, 2015 titled "*Rate-making Associated with Distributor Consolidation*" (2015 Report). In this report, the OEB has provided the opportunity for distributors to defer rebasing for a period up to ten years following the closing of a consolidation transaction. This deferred rebasing period is intended to enable distributors to fully realize anticipated efficiency gains from the transaction and retain achieved savings for a period of time to help offset the costs of the transaction.

*****

The OEB considers that certain aspects of a consolidation transaction are not relevant in assessing whether the transaction is in the public interest, either because they are out of scope, or because the OEB has other approaches and instruments for ensuring that statutory objectives will be met. Accordingly, the OEB will not require applicants to file evidence on the following matters as part of a consolidation application.

1. Deliberations, activities, and documents leading up to the final transaction agreement

As set out in the Combined Proceeding decision, and confirmed in recent decisions,[4] the question for the OEB is neither the why nor the how of the proposed transaction. The application of the "no harm" test is limited to the effect of the proposed transaction before the OEB when considered in light of the OEB's statutory objectives.

The OEB determined in the Combined Proceeding decision that it is not the OEB's role to determine whether another transaction, whether real or potential, can have a more positive effect than the transaction that has been placed before the OEB. Accordingly, the OEB will not consider, whether a purchasing or selling utility could have achieved a better transaction than that being put forward for approval in the application.

Also as set out in the Combined Proceeding decision, the OEB will not consider issues relating to the overall merits or rationale for applicants' consolidation plans nor the negotiating strategies or positions of the parties to the transaction. The OEB will not consider issues relating to the extent of the due diligence, the degree of public consultation or public disclosure by the parties leading up to the filing of the transaction with the OEB.

Applicants and stakeholders should not file any of the following types of information as they are not considered relevant to the proceeding:

- Draft share purchase agreements and other draft confidential agreements and documents utilized in the course of the negotiation process

[4] Hydro One Inc./Norfolk Power Distribution Inc. Decision and Order and Procedural Order No. 8 – OEB File No. EB-2013-0196/EB-2013-0187/EB-2013-0198
Hydro One Inc./Woodstock Hydro Services Inc. Decision and Procedural Order No. 4 – OEB File No. EB-2014-0213

- Negotiating strategies or conduct of the parties involved in the transaction
- Details of public consultation prior to the filing of the application

2. *Implementing public policy requirements for promoting conservation, facilitating a smart grid and promoting renewable energy sources*

As previously discussed, the OEB's performance-based regulation, which includes performance monitoring and reporting based on standards, combined with the regulatory instruments of codes and licences, establishes a framework for success in achieving public policy requirements. A utility that does not meet established performance expectations is subject to corrective action by the OEB. Given these means for ensuring that public policy objectives are met by all regulated entities, the OEB is satisfied that the "no harm" test will be met for these objectives following a consolidation and there is no need or merit in further detailed consideration as part of a consolidation transaction. For these reasons, no evidence is required to be filed for these issues.

3. *Prices not related to a utility's own costs*

The OEB's review is limited to the components of the distribution business and the costs and services directly under a distributor's control. For example, one of the mandates of a distributor is to pass-through certain wholesale market and commodity related costs to customers. These costs are passed through and not part of a utility's underlying costs to serve its customers. Accordingly, the prices of these services are not considered by the OEB in its review of a consolidation application.

5. Rate-Making Considerations Associated with Consolidation Applications

The OEB's policies on rate-making matters associated with consolidation in the electricity distribution sector are set out in two reports of the OEB. The first report titled "*Rate-making Associated with Distributor Consolidation*" issued on July 23, 2007 (2007 Report) was supplemented by the 2015 Report, issued under the same name, as previously indicated.[5]

This section of the Handbook consolidates information that is provided in these two reports and identifies the key rate-making considerations expected to arise in

[5] Report of the Board: Rate-Making Associated with Distributor Consolidation, March 26, 2015

consolidation transactions. Applicants are, however, encouraged to review both reports in preparing their applications for both the consolidation transaction and subsequent rate application.

Rate-setting following a consolidation will not be addressed in an application for approval of a consolidation transaction unless there is a rate proposal that is an integral aspect of the consolidation e.g. a temporary rate reduction. Rate-setting for the consolidated entity will be addressed in a separate rate application, in accordance with the rate setting policies established by the OEB. The OEB's review of a utility's revenue requirement, and the establishment of distribution rates paid by customers, occurs through an open, fair, transparent and robust process ensuring the protection of customers.

Rate-Setting Policies

The rate making considerations relating to consolidation that applicants and parties need to be aware of are:

- Deferred Rebasing
- Early Termination of Pre-Consolidation Rate-Setting term
- Early Termination or Extension of Deferred Rebasing Period
- Rate Setting During Deferred Rebasing Period
- Off Ramp
- Earnings Sharing Mechanism
- Incremental Capital Investments During Deferred Rebasing Period
- Future Rate Structures
- Deferral and Variance Accounts

Deferred Rebasing

The setting of rates for a consolidated entity using a cost of service methodology or a Custom Incentive Rate-setting method (both referred to in this document as rebasing of rates) involves a detailed assessment by the OEB of a utility's underlying costs. A consolidated entity is required to file a separate application with the OEB under Section 78 of the OEB Act for a rebasing of its rates. This typically takes place at some point in time following the OEB's approval of a consolidation.

To encourage consolidations, the OEB has introduced policies that provide consolidating distributors with an opportunity to offset transaction costs with any achieved savings. The 2015 Report permits consolidating distributors to defer rebasing for up to ten years from the closing of the transaction. The 2015 Report also states that consolidating entities deferring rebasing for up to five years may do so under the policies established in the 2007 Report.[6] The extent of the deferred rebasing period is at the option of the distributor and no supporting evidence is required to justify the selection of the deferred rebasing period subject to the minimum requirements set out below.

While the OEB has determined that allowing a longer deferred rebasing period is appropriate to incent consolidation, there must be an appropriate balance between the incentives provided to utilities and the protection provided to customers. The OEB will therefore require consolidating distributors to identify in their consolidation application the specific number of years for which they choose to defer. It is not sufficient for applicants to state that they will defer rebasing for <u>up to</u> 10 years. Distributors must select a definitive timeframe for the deferred rebasing period. This will allow the OEB to assess any proposed departure from this stated plan.

In addition, distributors cannot select a deferred rebasing period that is shorter than the shortest remaining term of one of the consolidating distributors. Therefore, a consolidated entity can only rebase when:

i) The selected deferred rebasing period has expired, and
ii) At least one rate-setting term of one of the consolidating entities has also expired.

Early Termination of Pre-Consolidation Rate-setting Term

At the time distributors first enter into a consolidation transaction, consolidating distributors may be on any one of the rate setting mechanisms and may not necessarily be using the same rate-setting mechanism or have the same termination dates.

A consolidated entity may apply to the OEB to rebase its rates as a consolidated entity through a cost of service or Custom IR application following the expiry of the original rate-setting term of at least one of the consolidating entities and once the selected deferred rebasing period has concluded. If, however, a consolidated entity wishes to rebase its rates prior to the end of the pre-consolidation rate-setting term of the distributor that has the earliest termination date, the consolidated entity must demonstrate the need for this “early rebasing” as part of the early rebasing application.

[6] Report of the Board on Rate-making Associated with Distributor Consolidation, July 23, 2007

The OEB established its approach to early rebasing in a letter dated April 20, 2010 and reiterated it in the RRFE. The OEB expects a distributor that seeks to have its rates rebased earlier than scheduled to clearly demonstrate why early rebasing is required and why and how the distributor cannot adequately manage its resources and financial needs during the remaining years of its current rate term.

Early Termination or Extension of Selected Deferred Rebasing Period

The OEB considers that consolidations can provide for greater efficiencies and benefits to customers and is committed to reducing regulatory barriers to consolidations. The OEB has allowed for a deferred rebasing period to eliminate one of the identified barriers to consolidations. The OEB remains of the view that having consolidating entities operate as one entity as soon as possible after the transaction is in the best interest of consumers. That being said, when a consolidating entity has opted for a deferred rebasing period, it has committed to a plan based on the circumstances of the consolidation. For this reason, if the consolidated entity seeks to amend the deferred rebasing period, the OEB will need to understand whether any change to the proposed rebasing timeframe is in the best interest of customers.

Distributors who subsequently request a shorter deferred rebasing period than the one that has been selected (and where at least one of the pre-consolidation rate-setting plans has expired) will be required to file rationale to support the need to amend the previously selected deferred rebasing period. Similarly, a consolidated entity having selected a deferred rebasing period less than 10 years, that seeks to extend its selected deferred rebasing period must explain why this is required.

Rate Setting during Deferred Rebasing Period

Under the OEB's RRFE, there are three rate-setting options: Price Cap Incentive Rate-Setting (Price Cap IR or PCIR), Custom Incentive Rate-Setting (Custom IR or CIR) and Annual Incentive Rate-Setting Index (Annual IR Index or AIRI). The term of the Price Cap IR and Custom IR options is normally five years. The Annual IR Index option has no specific term.

Consolidating distributors may be on any one of the rate-setting mechanisms and may not necessarily be using the same rate-setting mechanism or have the same termination dates. The 2015 Report clarified how rates will be set for a distributor who is a party to a consolidation transaction during any deferred rebasing period after the distributor's original incentive rate-setting plan has concluded:

- A distributor on Price Cap IR, whose plan expires, would continue to have its rates based on the Price Cap IR adjustment mechanism during the remainder of the deferred rebasing period.
- A distributor on Custom IR, whose plan expires, would move to having rates based on the Price Cap IR adjustment mechanism during the remainder of the deferred rebasing period.
- A distributor on the Annual IR Index will continue to have rates based on the Annual IR Index, until it selects a different rate-setting option.

Table 1 below illustrates six potential scenarios for rate-setting during the deferred rebasing period, assuming the consolidation of two distributors. The table also sets out the conditions that must be met by a consolidated entity that elects to rebase its rates. While Table 1 is intended to illustrate a situation of two consolidating distributors, the OEB is aware that future consolidations may involve several consolidating distributors as well as the possibility of multiple successive consolidation transactions by a single consolidated entity. For unique circumstances, the OEB may need to assess the rate-setting proposals on a case by case basis.

Table 1 - Rate-Setting Options During the Deferred Rebasing Period

Going in Rates
As of the date of the closing of the transaction. Assumes two distributors.

	Both on PCIR	One on PCIR and one on CIR	Both on CIR
Deferral Period	Continue with current plans for chosen deferred rebasing period.	LDC on PCIR continues on current plan for chosen deferred rebasing period and LDC on CIR moves to PCIR for the remaining years of chosen deferred rebasing period, following the expiration of the CIR term.	Continue with current plans. Once each term expires, each LDC will move to PCIR for the remaining years of the chosen deferred rebasing period.
	OR	OR	OR
Rebasing Options	Rebase as a consolidated entity following the expiration of one of the entities' term and once the selected deferred rebasing period has concluded.	LDC on PCIR continues on current plan. If its term expires in advance of the expiration of the other LDC's CIR term the consolidated entity may rebase once the selected deferred rebasing period has concluded.	Continue with current plans. Once the earlier of the two terms expires the consolidated entity may rebase once the selected deferred rebasing period has concluded.
		OR	
		If the term for the LDC on CIR expires first, the consolidated entity may rebase following the expiration of the CIR term and once the selected deferred rebasing period has concluded.	

	One on PCIR and one on AIRI	Both on AIRI	One on AIRI and one on CIR
Deferral Period	Continue with current plans for chosen deferred rebasing period.	Continue with current plans for chosen deferred rebasing period.	LDC on AIRI continues on current plan for chosen deferred rebasing period and LDC on CIR moves to PCIR for the remaining years of chosen deferred rebasing period, following the expiration of the CIR term.
	OR	OR	OR
Rebasing Options	Consolidated entity may rebase once the selected deferred rebasing period has concluded.	Consolidated entity may rebase once the selected deferred rebasing period has concluded.	Consolidated entity may rebase once the selected deferred rebasing period has concluded.

Off Ramp

As set out in the OEB's RRFE, each incentive rate-setting method includes an annual return on equity (ROE) dead band of ±300 basis points. When a distributor performs outside of this earnings dead band, a regulatory review may be initiated by the OEB. The OEB requires consistent, meaningful and timely reporting to effectively monitor utility performance and determine if expected outcomes are being achieved. The OEB's performance monitoring framework allows the OEB to take corrective action if required, including the possible termination of the distributor's rate-setting method and requiring the distributor to have its rates rebased.

The dead band of ±300 basis points on ROE continues to apply to utilities who have deferred rebasing due to consolidation. For utilities who defer rebasing up to five years, the OEB may initiate a regulatory review if the earnings are outside of the dead band. For utilities deferring rebasing beyond five years, an earnings sharing mechanism is required above ±300 basis points as discussed in the next section.

Earning Sharing Mechanism (ESM)

Consolidating entities that propose to defer rebasing beyond five years, must implement an ESM for the period beyond five years.[7] The ESM is designed to protect customers and ensure that they share in any increased benefits from consolidation during the deferred rebasing period.

In the 2015 Report, the OEB determined that under the ESM, excess earnings are shared with consumers on a 50:50 basis for all earnings that are more than 300 basis points above the consolidated entity's annual ROE. Earnings will be assessed each year once audited financial results are available and excess earnings beyond 300 basis points will be shared with customers annually. No evidence is required in support of an ESM that follows the form set out in the 2015 Report.

There are numerous types and structures of consolidation transactions, and there can be significant differences between utilities involved in a transaction. The ESM as set out in the 2015 Report may not achieve the intended objective of customer protection for all types of consolidation proposals. For these cases, applicants are invited to propose an ESM that better achieves the objective of protecting customer interests during the

[7] Report of the Board: Rate-Making Associated with Distributor Consolidation, March 26, 2015, p.6

deferred rebasing period. For example, a large distributor that acquires a small distributor may demonstrate the objective of consumer protection by proposing an ESM where excess earnings will accrue only to the benefit of the customers of the acquired distributor.

Incremental Capital Investments during Deferred Rebasing Period

The Incremental Capital Module (ICM) is an additional rate-setting mechanism under the Price Cap IR option to allow adjustment to rates for discrete capital projects. The details of the mechanism are described in the *Report of the Board: New Policy Options for the Funding of Capital Investments: The Advanced Capital Module*, issued on September 18, 2014 and a supplemental report with further enhancements will be issued in January 2016.

The ICM is now available for any prudent discrete capital project that fits within an incremental capital budget envelope, not just expenditures that were unanticipated or unplanned. To encourage consolidation, the 2015 Report extended the availability of the ICM for consolidating distributors that are on Annual IR Index, thereby providing consolidating distributors with the ability to finance capital investments during the deferral period without being required to rebase earlier than planned.

The 2015 Report sets out that a distributor who is in the midst of the Custom IR plan at the time of the transaction and who consolidates with an entity operating under a Price Cap IR or an Annual IR Index may only apply for an ICM for investments incremental to its Custom IR plan. The rules that apply to a specific rate-setting method continue to apply even following a consolidation of distributors. To be specific, an ICM would not be available for the rates in the service area for which the Custom IR plan term applies until the term of the Custom IR ends and Price Cap IR applies. Materiality thresholds for the ICM will be calculated based on the individual distributors' accounts and not that of the consolidated entity.

Future Rate Structures

A consolidated entity is expected to propose rate structures and rate harmonization plans following consolidation at the time it files its rebasing application. Distributors are not required to file details of their rate-setting plans, including any proposals for rate harmonization, as part of the application for consolidation. These issues will be addressed at the time of rate rebasing of the consolidated entity.

A rate harmonization plan can propose the approach and timeline for harmonizing rate classes or provide rationale for why certain rate classes should not be harmonized based on underlying differences in cost structures and drivers. For acquisitions, distributors can propose plans that place acquired customers into an existing rate class or into a new rate class. However, the OEB expects that whichever option is adopted, rates will reflect the cost to serve the acquired customers, including the anticipated productivity gains resulting from consolidation.

Deferral and Variance Accounts

Where a transmitter or distributor has accumulated balances in a deferral or variance account, the question of who should pay for, or receive credits from the clearance of these balances is relevant to the consolidation only if it affects the financial viability of the acquiring utility or consolidated entity. A decision on the actual clearance of deferral or variance accounts would be part of a rate application, not an application seeking approval for consolidation.

INDEX: Schedule 1 – Relevant Sections of the OEB Act

Section 86 of the OEB Act

Change in ownership or control of systems

86. (1) No transmitter or distributor, without first obtaining from the Board an order granting leave, shall,

(a) sell, lease or otherwise dispose of its transmission or distribution system as an entirety or substantially as an entirety;

(b) sell, lease or otherwise dispose of that part of its transmission or distribution system that is necessary in serving the public; or

(c) amalgamate with any other corporation. 2003, c. 3, s. 55 (1).

Same

(1.1) Subsection (1) does not apply with respect to a disposition of securities of a transmitter or distributor or of a corporation that owns securities in a transmitter or distributor. 2002, c. 1, Sched. B, s. 9 (1).

Acquisition of share control

(2) No person, without first obtaining an order from the Board granting leave, shall,

(a) acquire such number of voting securities of a transmitter or distributor that together with voting securities already held by such person and one or more affiliates or associates of that person, will in the aggregate exceed 10 per cent of the voting securities of the transmitter or distributor; or

(b) acquire control of any corporation that holds, directly or indirectly, more than 10 per cent of the voting securities of a transmitter or distributor if such voting securities constitute a significant asset of that corporation. 1998, c. 15, Sched. B, s. 86 (2).

INDEX: Schedule 2 – Filing Requirements for Consolidation Applications

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Ontario Energy Board

Filing Requirements For Consolidation Applications

January 19, 2016

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Filing Requirements for Consolidation Applications

1. Introduction

Completeness and Accuracy of an Application

These filing requirements provide direction to applicants in preparing a consolidation application. It is expected that applicants will file applications consistent with the filing requirements. Applications must be accurate, and information and data presented must be consistent throughout the application. If an application does not meet all of these requirements, or if there are inconsistencies identified in the information or data presented, the OEB may put the application in abeyance, unless satisfactory justification for missing or inconsistent information has been provided or until revised satisfactory evidence is filed. If circumstances warrant, the OEB may require an applicant to file evidence in addition to what is identified in the filing requirements. An applicant should only file information that is relevant to the OEB's statutory objectives in relation to electricity. Applicants should refer to the Handbook on the OEB's expectations and approach to reviewing consolidation applications.

Certification of Evidence

An application filed with the OEB must include a certification by a senior officer of the applicant that the evidence filed is accurate, consistent and complete to the best of his or her knowledge.

Updating an Application

When material changes or updates to an application or other evidence are necessary, a thorough explanation of the changes must be provided, along with revisions to the affected evidence and related schedules. This process is contemplated in Rule 11.02 of the *Rules of Practice and Procedure* (the Rules). When changes or updates are contemplated in later stages of a proceeding, updates should only be done if there is a material change to the evidence already before the OEB. Rule 11.03 states that any such updates should clearly indicate the date of the revision and the part(s) revised.

Interrogatories

Interrogatories are an important part of the process of clarifying and testing evidence, however they must focus on issues that are relevant to the OEB's decision. Excessive interrogatories introduce inefficiency into the application process. The OEB advises applicants to consider the clarity, completeness and accuracy of their evidence and refer to the Handbook for what will be considered or not in order to reduce the need for interrogatories. The OEB also advises parties to carefully consider the relevance and materiality of information before requesting it through interrogatories. Parties must consult Rules 26 and 27 of the OEB's *Rules of Practice and Procedure*, April 24, 2014 revision, for additional information on the filing of interrogatories and responses and matters related to such filings.

Confidential Information

The OEB relies on full and complete disclosure of all relevant material in order to ensure that its decisions are well-informed. The OEB's expectation is that applicants will make every effort to file material contained in an application publicly and completely, and without redactions in order to ensure the transparency of the review process. The OEB's Rules and the *Practice Direction on Confidential Filings* (the Practice Direction) allow for applicants and other parties to request that certain evidence be treated as confidential. Where such a request is made, parties are expected to review and follow the Practice Direction. This includes assessment of the relevance of any requested document prior to filing it with the OEB and requesting confidential treatment. There is no requirement or expectation on applicants to file documents that are out of scope of the areas the OEB has determined are relevant to its consideration of a consolidation application as defined in the Handbook.

2. Information Required of Applicants

The OEB expects an application for consolidation to have the following components:

2.1 Exhibit A: The Index

	Content	Described in
Exhibit A	Index	2.1
Exhibit B	The Application	2.2
	Administrative	2.2.1
	Description of the Business of the Parties to the Transaction	2.2.2
	Description of the Transaction	2.2.3
	Impact of transaction on the OEB's statutory objectives	2.2.4
	Rate considerations for consolidation applications	2.2.5
	Other Related Matters	2.2.6

2.2 Exhibit B: The Application

2.2.1 Administrative

This section must include the formal signed application, which must incorporate the following:

- Legal name of the applicant or applicants
- Details of the authorized representative of the applicant/s, including the name, phone and fax numbers, and email and delivery addresses
- Legal name of the other party or parties to the transaction, if not an applicant
- Details of the authorized representative of the other party or parties to the transaction, including the name, phone and fax numbers, and email and delivery addresses
- Brief description of the nature of the transaction for which approval of the OEB is sought by the applicant or applicants

2.2.2 Description of the Business of the Parties to the Transaction

This section of the application requires the applicant to provide the following information on the parties to the proposed transaction:

- Describe the business of each of the parties to the proposed transaction, including each of their electricity sector affiliates engaged in, or providing goods or services to anyone engaged in, the generation, transmission, distribution or retailing of electricity.

- Describe the geographic territory served by each of the parties to the proposed transaction, including each of their affiliates, if applicable, noting whether service area boundaries are contiguous or if not the relative distance between service boundaries.

- Describe the customers, including the number of customers in each class, served by each of the parties to the proposed transaction.

- Describe the proposed geographic service area of each of the parties after completion of the proposed transaction.

- Provide a corporate chart describing the relationship between each of the parties to the proposed transaction and each of their respective affiliates.

- If the proposed transaction involves the consolidation of two or more distributors, please indicate the current net metering thresholds of the utilities involved in the proposed transaction. The OEB will, in the absence of exceptional circumstances, add together the kW threshold amounts allocated to the individual utilities and assign the sum to the new or remaining utility. Applicants must indicate if there are any special circumstances that may warrant the OEB using a different methodology to determine the net metering threshold for the new or remaining utility.

2.2.3 Description of the Proposed Transaction

This section of the application requires the applicant to provide the following:

- Provide a detailed description of the proposed transaction.
- Provide a clear statement on the leave being sought by the applicant, referencing the particular section or sections of the *Ontario Energy Board Act, 1998*.
- Provide details of the consideration (e.g. cash, assets, shares) to be given and received by each of the parties to the proposed transaction.
- Provide all final legal documents to be used to implement the proposed transaction.
- Provide a copy of appropriate resolutions by parties such as parent companies, municipal council/s, or any other entities that are required to approve a proposed transaction confirming that all these parties have approved the proposed transaction.

2.2.4 Impact of the Proposed Transaction

In reviewing an application, the OEB will apply the no harm test as outlined in the Handbook. Applicants are required to provide the following evidence to demonstrate the impact of the proposed transaction with respect to the OEB's first two statutory objectives.

Objective 1 – Protect consumers with respect to prices and the adequacy, reliability and quality of electricity service

- Indicate the impact the proposed transaction will have on consumers with respect to prices and the adequacy, reliability and quality of electricity service.
- Provide a year over year comparative cost structure analysis for the proposed transaction, comparing the costs of the utilities post transaction and in the absence of the transaction.

- Provide a comparison of the OM&A cost per customer per year between the consolidating distributors.

- Confirm whether the proposed transaction will cause a change of control of any of the transmission or distribution system assets, at any time, during or by the end of the transaction.

- Describe how the distribution or transmission systems within the service areas will be operated.

Objective 2 – Promote economic efficiency and cost effectiveness and to facilitate the maintenance of a financially viable electricity industry

- Indicate the impact that the proposed transaction will have on economic efficiency and cost effectiveness (in the distribution or transmission of electricity), identifying the various aspects of utility operations where the applicant expects sustained operational efficiencies (both quantitative and qualitative).

- Identify all incremental costs that the parties to the proposed transaction expect to incur which may include incremental transaction costs (e.g. legal, regulatory), incremental merged costs (e.g. employee severances), and incremental on-going costs (e.g. purchase and maintenance of new IT systems). Explain how the consolidated entity intends to finance these costs.

- Provide a valuation of any assets or shares that will be transferred in the proposed transaction. Describe how this value was determined.

- If the price paid as part of the proposed transaction is more than the book value of the assets of the selling utility, provide details as to why this price will not have an adverse effect on the financial viability of the acquiring utility.

- Provide details of the financing of the proposed transaction.

- Provide financial statements (including balance sheet, income statement, and cash flow statement) of the parties to the proposed transaction for the past two most recent years.

- Provide pro forma financial statements for each of the parties (or if an amalgamation, the consolidated entity) for the first full year following the completion of the proposed transaction.

2.2.5 Rate considerations for consolidation applications

Applicants are required to provide the information with respect to the following rate making considerations relating to consolidation:

- Indicate a specific deferred rate rebasing period that has been chosen.
- For deferred rebasing periods greater than five years:
  - Confirm that the ESM will be as required by the 2015 Report and the Handbook
  - If the applicant's proposed ESM is different from the ESM set out in the 2015 Report, the applicant must provide evidence to demonstrate the benefit to the customers of the acquired distributor

2.2.6 Other Related Matters

Applicants have, in previous consolidation applications, made the following additional requests to the OEB which have formed part of the OEB's determination of a consolidation application:

a) Implementation of new or the extension of existing rate riders
b) Transfer of rate order and licence
c) Licence amendment and cancellation
d) Approval to continue to track costs to the deferral and variance accounts currently approved by the OEB
e) Approval to use different accounting standards for financial reporting following the closing of the proposed transaction

Applicants are required to provide justification for these types of requests and for any other requests for which a determination is being sought from the OEB as part of a consolidation application.

- End of document –