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VIA COURIER, RESS and EMAIL

March 21, 2016

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
2300 Yonge Street, Suite 2700
Toronto, ON M4P 1E4

Re: Ontario Energy Board Generic Proceeding
Natural Gas Community Expansion
Board File No.: EB-2016-0004

Pursuant to the Board's Procedural Order No. 2 dated March 9, 2016, attached please find two copies of Enbridge Gas Distribution's evidence.

This submission was filed through the Board's Regulatory Electronic Submission System (RESS). Confirmation of filing is attached to this letter.

Please contact the undersigned if you have any questions.

Yours truly,

[original signed]

Kevin Culbert
Senior Manager,
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cc: All parties to EB-2016-0004

EVIDENCE OF ENBRIDGE GAS DISTRIBUTION

Purpose

1. On February 5, 2016 the Ontario Energy Board (the "OEB" or the "Board") issued Notice of a generic proceeding to consider what mechanisms may be used to recover the costs of expanding natural gas service to Ontario communities that are currently not served. Subsequent to the issue of this notice on March 4, 2016 the Board issued a letter advising all parties to the EB-2016-0004 proceeding that the Board had decided to suspend the current filing schedule until further notice pending the issuance of a procedural order outlining revised schedule. Further to the Board's notice of March 4, 2016 on March 9, 2016 the Board issued its second procedural order in this proceeding. In addition to providing a new schedule for this proceeding the EB-2016-0004 Procedural Order Number 2 also provides an expanded and finalized issues list.

2. The purpose of this evidence is to present to the Board, the positions of Enbridge Gas Distribution Inc., ("Enbridge" or the "Company") with respect to the twelve issues identified in the final issues list that accompanied the Board's March 9, 2016 order in this proceeding. In this evidence the Company will also provide the Board with a proposal that meets the Provincial objective of expanding natural gas service to currently unserved communities in a manner that would result in reasonable rate impacts to existing and potential customers.

Enbridge Position on Issues Identified in the Draft Issues List

Issue #1: *What is considered a community in the context of this proceeding?*

3. Enbridge agrees with the position set out by Union Gas in its EB-2015-0179 application that defines the criteria for the projects / communities that would be eligible for exemptions from the current EBO 188 Guidelines. These definitions are as follows:

    1) Community Expansion Project – Defined as a natural gas system expansion project which will provide first time natural gas system access where a minimum of 50 potential customers in homes and businesses already exist, for which economic feasibility guidelines permit a PI of less than 1.0; and

2) Small Main Extension Project – Defined as all other forms of distribution expansion which provide first time natural gas system access to customers.

Issue #2*: Does the OEB have the legal authority to establish a framework whereby the customers of one utility subsidize the expansion undertaken by another distributor into communities that do not have natural gas service?*

4. The Board's authority to approve rates for the sale of gas and for the transmission, distribution and storage of gas is set out in section 36 of the *Ontario Energy Board Act, 1998*. Section 36 says that the Board may make orders approving or fixing just and reasonable rates and that, in approving or fixing just and reasonable rates, the Board may adopt any method or technique that it considers appropriate.

5. The scope of the Board's authority under section 36 was considered by the Ontario Divisional Court in a case (the "Low Income" case) involving the Board's jurisdiction to implement a low income affordability program (*Advocacy Centre for Tenants-Ontario et al v. Ontario Energy Board*, 2008 CanLII 23487). In the Low Income case, the majority of the Divisional Court made clear that the "traditional approach" of cost of service continues to be the root principle of the determination of rates by the Board under the statutory provisions that authorize the Board to adopt any method or technique in approving or fixing just and reasonable rates. The majority of the Court said that a cost of service approach is necessary to meet the fundamental, core objective of balancing the interests of all consumers and the natural monopoly utility in rate/price setting. The majority also referred to cost of service as the "starting point building block in rate setting".

6. The majority decision in the Low Income case goes on to indicate that, so long as the global amount of return to the utility based upon a cost of service analysis is achievable, then the rates to generate that amount are a matter for the Board's discretion in its ultimate goal and responsibility of approving and fixing just and reasonable rates. The Court said that, when the Board determines rates to recover the global amount based on a cost of service analysis, the Board has the jurisdiction to take into account ability to pay. In reaching these conclusions, the Court noted that the power granted to a regulatory authority must be exercised reasonably and according to the law and cannot be exercised for a collateral object or an extraneous and irrelevant purpose, however commendable.

7. A framework that requires the customers of one utility to subsidize expansion undertaken by another distributor would be contrary to the cost of service approach that, as set out in the Low Income decision, continues to be the root principle of the determination of rates by the Board. The cost of service of a particular utility does not and cannot include costs of subsidizing activities of another utility. Furthermore, in order to give effect to a framework for the customers of one utility to subsidize expansion by another utility, it would be necessary for the Board to allocate the subsidization amounts to particular utilities and for the benefit of particular communities that are not currently served by a distributor. In the Company's view the Board has no jurisdiction under the governing legislation to make decisions about how funds recovered in rates from customers of a utility are to be allocated to other utilities and for the benefit of particular communities not currently served by a distributor.

Issue #3: *Based on a premise that the OEB has the legal authority described in Issue #1, what are the merits of this approach? How should these contributions be treated for ratemaking purposes?*

8. Enbridge is of the view that there are no merits to this approach. The notion of a mechanism whereby the customers of one utility subsidize the expansion of another is flawed in a number of respects.

9. The Discounted Cash Flow ("DCF") analysis that is currently employed to test the economic feasibility of projects today is time limited. Under EBO 188 the profitability index ("PI" or "feasibility") test that is used is limited to either a twenty or forty year time horizon, based on customer type. The nature of community expansion projects typically requires a large cash outlay in the initial year(s) which is recovered over a twenty or forty year period of time.

10. In the early years community expansion projects tend to be detractors to profitability, however at some future point the cash flows cross over such that these projects begin to contribute to profitability. Except for the most profitable customer additions, existing customers typically support the revenue requirement of new customers for a period of time through rates. Overtime, as the revenue requirement associated with these new customers' declines, they contribute to lowering rates for customers who preceded them and cross subsidize newer customers. Under this model Enbridge has been successful in doubling the

number of customers in its franchise since the early 90's which contributed to minimizing of rate increases during this period.

11. This view of a profitability curve, taken in the context of Enbridge's proposal is illustrated below in Table 9. Table 9 shows the estimated rate impact of Enbridge's community expansion proposal based on thirty-nine community expansion projects the Company now has under consideration. The impact on existing customers peaks in year nine of the analysis and then begins to decline. This decline is indicative of when the incremental revenue contribution of customers in this portfolio begins to exceed the incremental revenue requirement they impose on other customers. Extending this example to any cross utility subsidy proposal would mean that at some point in the future customers of the utility that received the subsidy would need to return these amounts to customers of the utilities that originally paid them in order to be fair to customers that had helped fund the extension of service to them nine years earlier.

12. Additionally, the use of cross company subsidies would not be in the best interest of all ratepayers in the province as it would erode the economies of scale developed over a long period of time by both Enbridge and Union Gas. Such economies of scale are associated with the operating and carrying costs on the assets which the ratepayers for each of the distributors have been contributing towards for many years. Any cross company subsidy now, would see each of those utilities ratepayers lose such benefits and would see them not only paying for the related operating and carrying costs on assets for their distributor but for other distributors as well.

13. Cross company rate subsidization is not only unfair to existing ratepayers but would require extensive efforts in attempting to accumulate all of the volumes and cost data across all utilities in order to ensure cost causality and cost allocation principles would be applied equitably across all utilities, in essence creating one rate structure for the province which in Enbridge's view is not achievable or appropriate.

14. It is somewhat ironic that a proposal has been made that would result in more regulated natural gas utilities at the same time the province is promoting the consolidation of energy distributors in the electricity sector, as indicated by the following statement:

> *To promote consolidation of the electricity distribution sector, the government has announced in the **2015 Ontario Budget** that received Royal Assent on June 4, 2015, a time-limited relief on taxes pertaining to transfers of electricity assets for all Municipal Electricity Utilities, including transfers to the private sector.* (Ontario Ministry of Finance website: http://www.fin.gov.on.ca/en/tax/ea/index.html)

15. More regulated utilities would increase the level of effort and cost required to regulate them. In short the regulatory burden would increase. In addition to rate regulation any party seeking to legally transport or distribute natural gas in Ontario will also need to qualify for required licensing and presumably there would be costs associated with policing the terms of these licenses. Beyond these concerns, if a cross company subsidy program were to be implemented the Board would have numerous questions to answer with respect to its operation, some of these questions are:

    - Who would administer such a program?
    - What party would collect and hold such funds?
    - On what basis would application for funding be considered?
    - How would projects to be funded be evaluated? On what criteria?
    - How would applications be vetted in terms of consistency in cost and revenue forecasts?
    - What would the administration of such a program cost?

16. Clearly, the introduction of such a program would be costly to administer and these costs would ultimately be borne by all natural gas ratepayers. Further, significant time and effort would be required to compare competing proposals on an equitable manner. And lastly, if the program is to be fair to all natural gas customers the administrator would need to monitor projects that benefited from the cross-company subsidies over their lives in order to return past contributions to the contributors once these projects reach a point where they begin to generate positive returns.

How should these contributions be treated for ratemaking purposes?

17. Enbridge has already stated that it does not believe that cross company subsidies are appropriate. If a program were implemented that would in effect collect contributions from all natural gas customers province-wide and use these funds to subsidize natural gas community expansion projects across a number of different

gas distributors, Enbridge acknowledges that these funds could be treated as contributions in aid of construction.

Issue #4: *Should the OEB consider exemptions or changes to the EBO 188 guidelines for rural and remote community expansion projects?*

18. Yes. With respect to the specific questions raised by this issue:

Issue #4(a) - Should the OEB consider projects that have a portfolio profitability index (PI) less than 1.0 and individual projects within a portfolio that have a PI lower than 0.8?

19. Enbridge is of the view that if the extension of the natural gas distribution system to currently unserved communities is to occur that the OEB will need to exempt many of these projects from this requirement.

Issue #4 (b) - What costs should be included in the economic assessment for providing natural gas service to communities and how are they to be determined and calculated?

20. It is the position of Enbridge that there are no changes required to EBO 188 with respect to the costs that should be included in the economic assessment of providing natural gas service to communities and that there are no changes required in terms of how such costs are treated or the economic feasibility of projects calculated.

Issue #4(c) - What, if any, amendments to the EBO 188 and EBO 134 Guidelines would be required as a result of the inclusion of any costs identified above?

21. Enbridge believes that further revisions or exemptions from the current EBO 188 Guidelines will be required in order to extend gas service to currently unserved communities in Ontario. With respect to the EBO 134 Guidelines the Company does not believe that any changes are required. The Company's proposal in this regard is outlined later in this evidence.

Issue #4(d) - What would be the criteria for the projects/communities that would be eligible for such exemptions? What, if any, other public interest factors should be included as part of this criteria? How are they to be determined?

22. With respect to eligibility criteria for communities that would be eligible for such exemptions please see the Company's response in respect of Issue #1.

23. In Enbridge's view one of the main reasons behind the province's desire to extend gas service to more remote communities is to provide these communities with what are characterized in the EBO 134 Guidelines as Stage 2 Benefits. Stage 2 Benefits are additional quantifiable benefits and costs which would arise from carrying out system expansion projects. In light of provincial government policy to expand gas service to unserved communities Enbridge believes that the Board should give more weight to Stage 2 Benefits in the context of community expansion projects.

24. The benefits associated with extending natural gas service to those residing in communities goes beyond the direct energy cost savings. Qualitatively, higher levels of disposable income will lead to increased spending resulting in benefits to parties within and beyond these communities that are involved in the manufacture and installation of these products and services. The conversion or replacement of heating systems, water heaters, and sales and installation of other natural gas appliances will create employment opportunities. Further, the availability of a less costly energy option will encourage growth in existing businesses and make these communities more attractive to new businesses, again leading to economic growth and employment opportunities in these communities.

25. The extension of natural gas service to these communities will benefit all ratepayers. New customers will benefit from fuel cost savings. The extended reach of the Company's gas distribution system will provide the opportunity for future customer attachments to the system that would otherwise not occur beyond the ten year customer attachment forecast horizon applied in the current economic feasibility analysis. The incremental revenue generated by these future customer attachments will benefit all customers. All customers will also benefit as a result of the Company being able to achieve increased economies of scale and by being able to spread fixed cost over a broader customer base.

26. As to how these other public interest factors are valued and determined Enbridge suggests that the Board should continue to rely on what it had previously determined at paragraph 6.74 of its EBO 134 Decision where it determined that "The second stage should be designed to quantify other public interest factors not considered at stage one." Stage one being a DCF analysis. "All quantifiable other

public interest information as to the costs and benefits should be provided at this stage."

Issue #4(e) – Should there be exemptions to certain costs being included in the economic assessment for providing natural gas service to communities that are not served? If so, what are those exemptions and how should the OEB consider them in assessing to approve specific community expansion projects?

27. As indicated in the Company's response to Issue #4(b) Enbridge is of the view that in terms of the costs to be included in the economic assessment of community expansion projects that the provisions of EBO 188 should continue to apply.

Issue #4(f) – Should the economic, environmental and public interest components in not expanding natural gas service to a specific community be considered? If so, how?

28. This question asks the inverse of the second two issues outlined in Issue # 4(d). It is the Company's view that the benefits foregone in not expanding gas service to a specific community would essentially be equivalent the Stage 2 Benefits described in the Enbridge's response to Issue #4(d) expressed as an opportunity cost.

Issue #5: *Should the OEB allow existing natural gas distributors to establish surcharges from customers of new communities to improve the feasibility of potential community expansion projects? If so, what approaches are appropriate and over what period of time?*

29. Enbridge is of the view that in order to bridge the economic gap posed by the majority of community expansion projects it will be necessary to implement some form of increased rate that would apply to customers located within designated community expansion projects along with other tools that will enhance the economic viability of such projects. From an administrative standpoint the Company believes that the most efficient way to do this would be by way of a community expansion surcharge in the form of a rider to existing rates. Enbridge has outlined its proposal to enhance the feasibility of community expansion projects by implementing a rate surcharge later in this document.

Issue #6: *Are there other ratemaking or rate recovery approaches that the OEB should consider?*

30. Union Gas made a proposal to the Board in its EB-2015-0179 application that would enable it to recover the costs associated with the extension of its system into unserved communities that shares the cost between new customers that would be located in newly serviced communities and its existing customer base. Enbridge's proposal shares some aspects with the Union Gas proposal but also includes some elements that are different. There are likely other options that could be considered and are likely to be tabled in this proceeding. Enbridge is open to learn of these ideas and consider incorporating them in its proposal where appropriate.

Issue #7: *Should the OEB allow for the recovery of the revenue requirement associated with community expansion costs in rates that are outside the OEB approved incentive ratemaking framework prior to the end of any incentive regulation plan term once the assets are used and useful?*

31. Yes, the OEB should allow for the recovery of the associated revenue requirement prior to the end of any current incentive regulation plan. Further the Board should allow for the recovery of the associated revenue requirement in any ratemaking model that may be approved by the Board in the future.

Issue #8: *Should the OEB consider imposing conditions or making other changes to Municipal Franchise Agreements and Certificates of Public Convenience and Necessity to reduce barriers to natural gas expansion?*

32. No. Enbridge sees no reason to impose further conditions or to make other changes to the current form of Municipal Franchise Agreement or Certificates of Public Convenience and Necessity. There is nothing today to prevent an unserved municipality from initiating a competitive process to identify potential natural gas service providers and municipal franchise agreements are non-exclusive.

Issue #9: *What types of processes could be implemented to facilitate the introduction of new entrants to provide service to communities that do not have access to natural gas. What are the merits of these processes and what are the existing barriers to*

implementation? (e.g. Issuance of Request for Proposals to enter into franchise agreements)

33. As noted in Enbridge's response to Issue #7 the Company is not aware of any barrier to a municipality soliciting proposals for natural gas service. In Enbridge's view the larger question is whether or not adding new entrants to the market for regulated natural gas distribution services is in the best interest of the Province. If the Board does determine that the addition of regulated natural gas distributors in Ontario is beneficial then these new entrants should be required to demonstrate their qualifications as an operator of natural gas facilities in a public forum in addition to demonstrating the economic benefit to the market beyond that provided by incumbent service providers.

Issue #10: *How will the Ontario Government's proposed cap and trade program impact an alternative framework that the OEB may establish to facilitate the provision of natural gas services in communities that do not currently have access?*

34. Enbridge has been actively working with the Province to make certain that natural gas and the infrastructure that delivers it will continue to be a significant part of a low carbon future.

35. In order to keep the Province's desire to reduce CO2 emissions in perspective it is important to consider the scale of the challenge in terms of the Ontario natural gas market. The peak day energy supply from the Ontario natural gas system is over 80,000 MW. In order to meet this demand with electricity, it would require the addition of over 90 nuclear reactors to produce the equivalent amount of energy. The delivery of energy would impose significant additional costs on the electricity transmission and distribution grid to meet peak day and annual demand. Annually, Enbridge alone delivers almost the equivalent amount of energy as Ontario's entire electricity grid. Enbridge's annual throughput of 440 BCF of natural gas which is equivalent to 130 TWh of electricity, is only 10 TWh less than Ontario's 2014 total electricity demand of 140 TWh. This information makes it obvious that an orderly economically efficient transition to a low-carbon economy will need to leverage existing pipelines and gas storage capabilities. There are a number of ways that this can be achieved. Enbridge is actively investigating:

- Conservation
    - Conservation has been shown to be the most cost effective way to reduce per-customer consumption, which simultaneously reduces emissions and customer bills. Customers saved $2.43 for every $1 spent by Enbridge on DSM.

- Greening the Natural Gas Supply
    - Renewable natural gas is GHG-free and could meet up to 18% of Ontario's demand by 2030 through anaerobic digestion and gasification technologies and future innovation can grow this number further.

    - Enbridge is in the planning stage of constructing a Power-to-Gas, energy storage plant to provide "green hydrogen" in the GTA which will convert off-peak, surplus renewable electricity (wind, hydro, etc.) to hydrogen and inject this into pipelines for delivery to consumers as zero-carbon transportation fuel, green heat, or redelivery back to the power grid where and when most needed. A pilot project in Europe has recently demonstrated a significant increase in GHG free RNG by combining the hydrogen produced from power to gas technology with the carbon dioxide that would otherwise be scrubbed out in the upgrading of biogas to RNG.

- Fuel Switching in the Transportation Sector
    - Natural gas has up to 25% lower GHG emissions and is up to 40% less expensive than diesel fuel or gasoline. Access to refueling stations in Ontario is limited, while government incentives exist in Quebec, BC, New York, Pennsylvania, Ohio, Illinois and other areas.

- Investments in Innovation
    - Enbridge anticipates that a significant portion of cap and trade funds will be directed toward the development and commercialization of innovation solutions to reduce carbon emissions and capture and sequester carbon. One example is Enbridge Inc's investment in Skyonic Corporation which is developing systems that capture carbon dioxide by mineralizing the gas through a chemical reaction that produces compounds including hydrochloric acid and calcium carbonate, or limestone, which may be used in products such as glass, paper and cement.

36. In terms of the impact of transitioning users of alternate fuels to natural gas the Canadian Gas Association recently released a report completed by ICF that quantifies the national economic benefit of the expansion of the country's natural gas system. The ICF study also estimates that investment in the expansion of the country's natural gas system would lead to a decrease in annual GHG emissions equivalent to over 75,000 tonnes of CO2 per year. Enbridge believes that this report can provide the Board with guidance as to how best to estimate the indirect benefits of extending the province's natural gas distribution system. In addition, while this report is focused on Canada as a whole, Enbridge believes the conclusions of this report can be applied to Ontario. (Reference: EB-2015-0179 CCC Interrogatory #5 at Exhibit B.CCC.5)

37. Enbridge has and will continue to work cooperatively with the Province to help lower CO2 emissions. There are a number of initiatives that Enbridge is pursuing that will help the Province achieve its carbon reduction goals. Some of these will result in reduced gas consumption in some market sectors while others will increase gas usage.

38. In the case of heating oil, diesel fuel for vehicles and propane natural gas provides a carbon reduction benefit. With respect to electricity the natural gas carbon advantage is clear when comparing the carbon footprint of natural gas to electricity for specific applications. Although counterintuitive, when natural gas is considered as the marginal fuel supporting electricity generation converting heating and water heating loads from electricity to natural gas will lead to reductions in the Province's CO2 emissions.

39. It is the Company's view that the Province's cap and trade program should not be considered in isolation in the determination as how best to consider the impact of this program on the feasibility of potential natural gas system expansion projects. What should be considered as part of any framework that the OEB may establish to facilitate the provision of natural gas services in communities that do not currently have access to gas service is what is known today. What is known today is the information that has been provided by the Province in its 2016 Budget. Such a framework should take this information into account and then evolve in response to the market as it responds to cap and trade and all of the developments that go along with it.

Issue #11: *What is the impact of the Ontario Government's proposed cap and trade program on the estimated savings to switch from other alternative fuels to natural gas and the resulting impact on conversion rates?*

40. In November 2015, Ontario released its Climate Change Strategy and is currently developing an action plan to deliver on that strategy. A key component of that action plan is to implement a cap-and-trade program intended to result in reduced Greenhouse Gas ("GHG") emissions. This intention was confirmed with the release of the province's 2016 Budget on February 25, 2016 which stated that the government will be instituting legislation that will define future emissions reduction targets for Ontario and set-out criteria and rules for governing the cap-and-trade carbon market and for the use of proceeds that the new system generates.

> Based on the current forecast for the price of carbon, the pump price of a litre of gasoline would increase 4.3 cents and the cost of a cubic metre of natural gas would rise by 3.3 cents as a result of cap and trade. (*Province of Ontario 2016 Budget, Chapter 1*)
>
> The government will also take steps to ensure that the net impact of cap and trade would not result in an overall increase in electricity costs for commercial and industrial consumers, and that there would be a modest benefit of up to $2 per month, on average, to residential consumers. (*Province of Ontario 2016 Budget, Chapter 1*)

41. The province's Budget document goes on to make reference to several programs that it has initiated that will also limit the financial impact of the introduction of cap and trade on energy consumers:

- Home Audit and Retrofit programs that provide homeowners with incentives to make energy efficiency upgrades. Under the programs, homeowners can receive incentives to offset the cost of energy audits and retrofits such as furnace and water heating systems replacement and insulation.
- Home Winterproofing and Weatherization programs that provide eligible low-income households with a free home assessment, water conservation measures, programmable thermostat and weatherization services (e.g., insulation and air sealing).
- Adaptive Thermostat program for Enbridge customers that offers participants a $75 incentive for the installation of an adaptive thermostat.

42. Given the above, it is the Company's expectation that the energy savings associated with conversions from propane and heating fuel oil will result in greater cost savings compared to what is available today as the consumption of these two

fuels release greater levels of CO2 as compared to natural gas. With respect the conversion of homes and businesses now using electricity as their primary means of heating and water heating the price advantage of natural gas is expected to diminish somewhat.

43. Based on the figures provided by the province in its 2016 Budget the implementation of cap and trade will cause the average cost for home heating with natural gas to increase by $5.00 per month or $60.00 per year and that the typical residential electricity user will see a monthly saving of $2.00 per month or $24.00 per year. Based on the figures provided in Table 1 and the expected impacts of the pending cap and trade program as articulated by the Province it is expected that the annual energy cost saving for the average residential customer converting their heating load from electricity to natural gas would fall from $2,165 per year to $2081 per year. The Company does not believe that this change will have any significant impact in the rate of customer conversion from existing fuel types to natural gas.

Issue #12: *How should the OEB incorporate the Ontario Government's recently announced loan and grant programs into the economic feasibility analysis?*

44. In 2014, the Province of Ontario announced its intention to support the extension of the Province's natural gas system through the provision of $200 million in Natural Gas Access Loans and $30 million in Natural Gas Economic Development grants. The province's intention to carry out these programs has been affirmed by both the Board's letter and mandate letters from the Premier of Ontario to the Minister of Economic Development, Employment and Infrastructure, The Minister of Energy, and the Minister of Agriculture. Copies of these letters found at Appendix A and Appendix N to Union's EB-2015-0179 Application respectively.

45. At this time the Company is not aware of any details of how these programs will be rolled out, how the funds will be allocated or how they would be applied so as to improve the viability of natural gas community expansion projects. Given that the details of these programs are not currently known it is difficult to speculate how the funds provided by loan and grant programs may factor into the economic feasibility analysis associated with community expansion projects. The appropriateness of taking these funds into account as part of the testing of the economic feasibility of

such projects will be dependent on how and to whom these funds will be distributed.

Enbridge Community Expansion Proposal

Market Background

46. Enbridge recognizes that in general natural gas continues to maintain price competitiveness in the Ontario market in most market sectors. Enbridge currently assumes annual natural gas consumption of 2,400 m^3 per year for the average Rate 1 residential customer. In terms of fuel cost savings, Enbridge estimates that under its current rates the average customer achieves annual average energy cost savings of approximately $1,700 based on market survey data and Company experience. Given an expected average cost of conversion of approximately $3,500 there are ample opportunities for potential customers located in communities where natural gas is currently not available to benefit from conversion to natural gas from alternate fuels.

Table 1: Estimated Annual Fuel Cost Savings, Equipment Conversion Cost and Payback Period for a Typical Residential Customer

Primary Fuel Type	Penetration %	Annual Bill	Natural Gas Saving (no SES)	Natural Gas Saving (with SES)	Estimated Conversion Cost	Payback Period (Years) (with SES)
Natural Gas	n/a	949				
Electricity	18%	3,114	2,165	1,613	7,250	4.5
Heating Oil	27%	2,771	1,822	1,270	3,500	2.8
Propane	43%	2,582	1,633	1,081	1,525	1.4
Wood	13%	1,537	588	36	3,500	96.3
Other (Equal Mix)	0%	2,619	1,670	1,118	3,500	3.1
Weighted Average	0.00	0	1,661	1,103	3,361	3.0

47. Overall, the competitive environment across the province is similar although there are localized variations in market characteristics that will have a marginal impact on the relative savings and payback periods various community expansion customers will achieve.

48. Enbridge currently has 40 communities (39 projects) under consideration as potential community expansion projects. Table 2 is a non-exhaustive list of these

communities along with the potential number of customers located in each community and the distance from each of these communities to the Company's existing natural gas distribution network. In aggregate these communities comprise over 20,000 potential customers. Table 2 also illustrates that some of these communities are quite small and in some instances are located a significant distance from the Company's existing natural gas distribution system.

Table 2: Communities Currently Under Consideration by Enbridge

	Community	Potential Customers	Distance from Source (kms)
Col 1	Col 2	Col 3	Col 4
1	Fenelon Falls & Bobcaygeon	6,242	47
2	Scugog Island	1,468	8
3	Cambray	400	10
4	Zephyr	250	11
5	Cotnam Island	100	10
6	Sarsfield	200	10
7	Udora	400	8
8	Wilkinson Sub, Innisfil	90	2
9	Town of Marsville	350	8
10	Town of Mansfield	294	8
11	Glendale Subdivision	100	6
12	Caledon - Humber Station	72	3
13	Enniskillen	200	10
14	Village of Lisle	400	5
15	5th Line, Mono Twp.	32	3
16	Sandford	200	9
17	Leasksdale	200	8
18	Curran	100	7
19	Bainsville	100	7
20	Westmeath	200	10
21	Haydon	100	10
22	Woodville	300	9
23	South Glengary	200	10
24	Caledon - Torbram Road	79	11
25	Chute-a-Blondeau	200	10
26	Hockley Village, Mono Twp.	64	13
27	Maxville	400	10
28	Lanark & Balderson	400	12
29	Douglas	200	20
30	Eganville	700	40
31	Kinburn/Fitzroy Harbour	500	15
32	St. Isidore	400	10
33	Kirkfield	800	25
34	Minden	1,414	68
35	Coboconk	400	40
36	Norland	200	50
37	Barry's Bay	500	90
38	Kinmount	200	60
39	Haliburtion (Dysert)	2,035	88
	Total	**20,490**	**779**

49. Enbridge's estimated capital cost for these projects takes into consideration that based on distance from existing natural gas distribution infrastructure and difficult construction conditions it may be more economical to deliver gas to some locales by way of liquefied natural gas ("LNG").

50. The Company has identified a subset of communities where a preliminary analysis indicates that gas service could be more economically provided through the utilization of LNG as an alternative to transmission mains as a means of transporting natural gas to these locations. This analysis shows that in cases where the capital costs of transmission main constitute disproportionate amounts of total project cost, LNG may provide a more economically attractive solution.

51. The Enbridge proposal adopts some of the elements that have been proposed by Union Gas in its EB-2015-0179 application, including the rate subsidy from existing customers, but includes several differences which are required to offer an expansion program of sufficient size and beneficial impact to communities. These differences are largely necessary due to the differences of distance and terrain between the regions served by the two utilities relative to the level of existing distribution rates.

52. Based on preliminary cost and market capture estimates Enbridge has determined that none of its thirty-nine potential projects would achieve Project PIs greater than or equal to 0.4 under Union's proposal. Enbridge had originally planned to adopt the Union Gas proposal with one significant change, which was to apply the Temporary Expansion Surcharge (the "TES") at the customer level for the same period of time for all customers served through the completion of a community expansion project as opposed to applying the charge for a fixed period of time for each project.

53. Union proposed that the term of the TES would be for a fixed period from four to ten years beginning from the date upon which natural gas service is made available to potential customers located within the bounds of a community expansion project until the expiry of the term of the TES specific to that community expansion project. For example, if the term of the TES for a community is five years, a customer that began to take service in the first month in which gas service is available to them would pay the TES for 60 months, whereas a customer that began to take service in the thirteenth month after gas service is available would pay the TES for only 48 months.

54. Like Union, Enbridge contemplated a single volume-based TES and Enbridge would have proposed the TES be tied to the customer's premise rather than the customer itself for a set period of time specific to each community expansion project or small main extension project. The TES would continue to be applicable to service at that premises until the expiry of the term of the TES applicable to that community expansion project or small main extension project regardless of who the customer is at a premise. In terms of this example all customers that initiate service within a community expansion project within the initial TES period would pay the TES for the full 60 months in the event that the TES term was determined to be 5 years. By doing so all customers served by the same community expansion project or small main extension project would contribute to the cost of the project on a proportionally equivalent basis.

55. This change in the application of the TES would have increased revenues derived from those new customers located in community expansion projects compared to Union's proposal and in turn improved the PIs for these projects. Even with this change based on preliminary cost and market capture estimates Enbridge has determined that very few of its thirty-nine potential projects would achieve Project PIs greater than or equal to 0.4 under this modified version of Union's proposal.

Table 3: Preliminary Profitability Analysis (Normal PI, Union Gas EB-2015-0179 PI, Rolling Term PI)

	Community	Potential Customers	Distance from Source (kms)	Total Investment Pipeline	Normal PI	Union Gas EB-2015-0179 PI	TES Rolling Term PI
Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Col 7	Col 8
1	Fenelon Falls & Bobcaygeon	6,242	47	111,956,990	0.26	0.38	0.44
2	Scugog Island	1,468	8	19,714,126	0.24	0.38	0.42
3	Cambray	400	10	7,583,140	0.19	0.30	0.33
4	Zephyr	250	11	5,184,375	0.16	0.26	0.28
5	Cotnam Island	100	10	2,171,890	0.13	0.23	0.26
6	Sarsfield	200	10	4,147,500	0.15	0.26	0.28
7	Udora	400	8	8,842,300	0.16	0.26	0.28
8	Wilkinson Sub, Innisfil	90	2	1,897,055	0.12	0.22	0.25
9	Town of Marsville	350	8	8,047,225	0.16	0.25	0.27
10	Town of Mansfield	294	8	6,817,129	0.15	0.25	0.27
11	Glendale Subdivision	100	6	2,509,250	0.12	0.21	0.23
12	Caledon - Humber Station	72	3	2,067,960	0.10	0.18	0.19
13	Enniskillen	200	10	5,109,500	0.14	0.23	0.24
14	Village of Lisle	400	5	9,966,800	0.15	0.24	0.26
15	5th Line, Mono Twp.	32	3	1,798,760	0.05	0.11	0.12
16	Sandford	200	9	5,590,500	0.13	0.22	0.23
17	Leasksdale	200	8	5,590,500	0.13	0.22	0.23
18	Curran	100	7	3,640,250	0.11	0.18	0.19
19	Bainsville	100	7	3,997,750	0.10	0.17	0.18
20	Westmeath	200	10	6,448,500	0.13	0.20	0.22
21	Haydon	100	10	4,478,750	0.10	0.16	0.17
22	Woodville	300	9	9,290,550	0.13	0.21	0.23
23	South Glengary	200	10	8,203,500	0.12	0.18	0.19
24	Caledon - Torbram Road	79	11	6,169,283	0.08	0.13	0.14
25	Chute-a-Blondeau	200	10	9,634,780	0.11	0.17	0.18
26	Douglas	200	20	12,369,720	0.10	0.16	0.16
27	Eganville	700	40	26,853,960	0.14	0.20	0.21
28	Kinburn/Fitzroy Harbour	500	15	22,175,820	0.12	0.19	0.20
29	Hockley Village, Mono Twp.	64	13	6,204,020	0.08	0.12	0.13
30	Maxville	400	10	14,727,400	0.13	0.20	0.21
31	Lanark & Balderson	400	12	16,337,800	0.13	0.19	0.20
32	St. Isidore	400	10	18,315,400	0.12	0.18	0.19
33	Kirkfield	800	25	38,400,280	0.12	0.18	0.19
34	Minden	1,414	68	78,108,620	0.11	0.17	0.18
35	Coboconk	400	40	39,174,640	0.08	0.14	0.14
36	Norland	200	50	44,373,120	0.07	0.12	0.12
37	Barry's Bay	500	90	71,120,300	0.09	0.13	0.13
38	Kinmount	200	60	52,654,120	0.08	0.12	0.12
39	Haliburtion (Dysert)	2,035	88	104,815,526	0.12	0.18	0.19

56. Table 3 shows the project PIs for all thirty-nine of the potential projects that Enbridge has investigated. None of these projects is capable of generating a PI value approaching the EBO 188 project PI threshold of 0.8. As illustrated in Column 7, none of these potential projects would achieve PIs of 0.4 in the event the relief Union Gas has sought in EB-2015-0179 were applied in assessing the economic feasibility of extending natural gas service to these communities. In fact, even when the Union Gas proposal is modified so as to apply the TES on a rolling

basis for ten years (Column 8) only two of the thirty-nine potential community expansion projects would achieve PIs in excess of 0.4, the revised project PI proposed by Union Gas.

57. The estimated capital costs used to determine the PIs shown in Table 3 are based on transmission main that would need to be built to extend service to these communities. The main factor leading to the low PIs for these potential projects are high capital costs that are driven by long distances from the existing gas distribution system, difficult terrain and contingency amounts that have been factored into these estimates. Enbridge expects that once more detailed assessments of the design and construction requirements of these projects and scheduling are completed and once the work is tendered contingency amounts can be reduced resulting in lower overall capital cost estimates.

Proposal Objectives

58. The parameters of Enbridge's proposal in this proceeding have been set to achieve the following objectives:

- To maximize the number of new communities to receive natural gas service without the use of provincial funding support, and
- To limit the rate impacts on existing customers to a maximum approximating $2 per month ($24 per year) over the multi-year expansion program.

59. Under this proposal Enbridge expects that it could complete approximately thirty-nine community expansion projects that would provide natural gas service to approximately 16,000 homes and businesses in the first ten years at a total capital cost of approximately $410 million. In assessing the second objective guidance can be found in the level of ratepayer subsidy that the Board has determined to be appropriate for the funding of the Demand Side Management programs of both Enbridge and Union Gas (EB-2015-0029/EB-2015-0049 Decision and Order, page 6).

Elements of the Enbridge Proposal

a) Adopt Union's proposed definitions of a Community Expansion Project and a Small Main Extension Project;

b) An ongoing System Expansion Surcharge (the "SES") to be applied to Community Expansion Projects and, Small Main Extension Projects of $0.23/m^3$;
c) Incremental Tax Equivalent ("ITE") mechanism to collect municipal contributions (for a ten year duration from the date of energizing assets);
d) Creation of an additional portfolio, the Community Expansion Portfolio (the "CEP"), where the portfolio would be managed such that the PI is maintained at a level of 0.5 or greater, and an exemption from EBO 188 that would allow individual community expansion projects to proceed at a PI of less than 0.8; and
e) A capital pass-through mechanism to incorporate Community Expansion Projects in rates immediately following their in-service dates.

a) Definition of Community Expansion Project and Small Main Extension Project

60. For the purpose of this proposal Enbridge will adopt the Union Gas proposed definitions for a community expansion project and a small main extension project as outlined in the evidence provided by Union in EB-2015-0179. These project types are defined as follows:

1) A Community Expansion Project – Defined as a natural gas system expansion project which will provide first time natural gas system access where a minimum of 50 potential customers in homes and businesses already exist, for which economic feasibility guidelines permit a PI of less than 1.0; and

2) A Small Main Extension Project – Defined as all other forms of distribution expansion which provide first time natural gas system access to customers.

b) System Expansion Surcharge ("SES")

61. The twin objectives of managing rate impacts for existing customers and providing greater access to natural gas for new communities have led the Company to conclude that it will be necessary to implement a different, higher, distribution rate for customers served through the completion of a community expansion project. Enbridge proposes that an ongoing SES to be applied to community expansion projects of $0.23/m^3$.

62. The surcharge would be paid by all customers located in areas served by designated community expansion projects for up to forty-years or until the project

achieved a PI of 1.0. Unlike Union, Enbridge proposes that these surcharge revenues be treated as part of general revenue which to an extent would reduce the portion of the Company's revenue requirement contributed by existing customers.

63. In the case of Small Main Extension Projects the SES would be applied until the project achieved a PI of 1.0. These projects would also be included in the CEP.

c) Municipal Contributions: Incremental Tax Equivalent

64. The Company's proposal concerning municipal contributions to community expansion projects is the same as that put forward by Union Gas. Union has proposed the introduction of a municipal contribution mechanism, described as the Incremental Tax Equivalent ("ITE"), to provide municipalities with a mechanism to contribute toward the economic feasibility of community expansion project feasibility. The Union Gas proposal calls for the ITE value to be based on the estimated value of incremental property taxes collected from the utility as a result of a community expansion project located within that municipality for a period of time that matches the term of Union Gas' proposed Temporary Expansion Surcharge (the "TES").

65. The Company proposes that the Enbridge ITE be in place for a ten year period of time. The ITE would only be applied in cases where a community expansion project proceeds with an indicated Project PI of less than 1.0. As in the Union Gas proposal, Enbridge would require the municipality to commit to the ITE applicable to the project prior to commencement of construction.

66. Municipalities are a beneficiary as they would see the elimination of a significant barrier to economic development, would receive incremental property taxes from the projects that would likely exceed increases in necessary municipal service costs, and in many cases, would benefit from reduced energy costs for municipally-owned facilities.

67. Similar to the revenues derived from the SES, Enbridge proposes that the ITE revenues be treated as part of the Company's general revenues, reducing the revenue requirement recovered from all customers in rates. The ITE provides a means for expansion area municipalities to financially support the projects and, in

combination with other components of the Company's proposal, addresses the revenue shortfall which is a key barrier to expansion for many communities.

d) Revisions to or Exemptions From EBO 188

The Community Expansion Portfolio (the "CEP")

68. As can be seen in Table 3 very few of the community expansion projects Enbridge currently has under consideration meet the revised economic feasibility threshold Project PI of 0.4 as proposed by Union Gas. Given this situation the Company has determined that a different approach will be necessary in order to meet the province's desired objective of "ensuring that Ontario consumers in communities that currently do not have access to natural gas are able to share in affordable supplies of natural gas." (Reference: OEB Letter, February 18, 2015. Can be found in Appendix A of this submission)

69. Given the estimated effect of both the SES and the ITE the thirty-nine community expansion projects that Enbridge now has under consideration are generating forecast PIs between 0.15 and 0.70. The overall PI of these projects if combined and aggregated in the CEP is 0.55. The Company understands that both on an individual basis and when viewed as a portfolio these projects do not meet the current EBO 188 requirement to achieve a project PI of 0.8. However, given the province's goal to extend natural gas service to rural and more remote communities and the intendent economic challenges, Enbridge is of the view that a reasonable way to meet this objective is to focus attention on the overall impact on all ratepayers as opposed to targeting the economic feasibility test at specific projects.

70. Enbridge proposes that rather than viewing community expansion projects individually from an economic perspective, these projects should be considered in their totality. This can be done through the establishment of a separate rolling project portfolio that captures all system expansion projects that fall within the definition of a community expansion project. Enbridge submits that it would manage this portfolio on a rolling basis such that its PI would be maintained at a level of 0.5 or greater. This commitment should provide the Board with a large degree of comfort that the implementation of these projects will have a reasonable and measured impact on all of the Company's customers.

Community Expansion Project – Project PI Relief

71. In order to work, the adoption of the Company's CEP proposal would require the projects included in this portfolio be exempt from the current EBO 188 Guideline of meeting a minimum project PI of 0.8.

Rolling Project Portfolio (the "RPP")

72. Table 7 shows the expected impact on Enbridge's RPP for the first eight years from the time projects in the proposed CEP come into service. This analysis assumes that;

- the two largest projects would be completed in the first year,
- five additional projects would be completed in each of years two through seven, and that seven projects would be completed in the eighth year.

73. It is evident from this analysis that if all of the projects under consideration by the Company were to be completed over the assumed period of time and their costs and anticipated revenues were to be included in the Company's RRP a minimum PI of 1.0 could not be maintained throughout this period of time for this portfolio. As such, as part of its proposal the Company requests that the projects captured in the CEP be excluded from its RPP.

Investment Project Portfolio (the "IP")

74. Table 8 shows the expected impact on Enbridge's IP for the first two projects from the time projects in the proposed CEP come into service. This analysis assumes the same project timing used in estimating impacts of the Enbridge proposal on the RPP.

75. As in the case of the RPP if all of the projects under consideration by the Company were to be completed over the assumed period of time and if their costs and anticipated revenues were included in the Company's IP, a minimum PI of 1.0 for the IP could not be maintained throughout this ten year time period. As with the RPP, part of the Company's proposal is a request to the Board that the projects captured in the CEP be excluded from its IP.

e) Y-Factor Treatment for Community Expansion Projects

76. The cost associated with potential community expansion projects was not included in the Company's current incentive rate model. Part of the Company's proposal calls for the recovery of the revenue requirement prior to the end of the current incentive regulation plan. Further, this proposal requests that the Board allow the recovery of the associated revenue requirement in any ratemaking model that may be approved by the Board in the future.

77. The Company proposes that the incremental revenue requirements associated with annual capital expenditures related to community expansion projects approved by the Board pursuant to "leave to construct" applications and included in the CEP, shall be treated as Y factors. The incremental revenue requirement impact associated with this Y factor would be addressed as part of the Company's annual rate setting process pursuant to the process set-out in the Company's current incentive rate model and future rate setting models and passed through to rates and allocated to rate classes in accordance with the latest Board-approved cost allocation methodology and rate design principles.

Customer and Ratepayer Impacts

78. As a starting point the Company calculated the PIs for each of the forty community expansion projects currently under consideration in order to present feasibility under the EBO 188 requirements. This information is presented in Table 4 for each of these communities.

79. The calculation of Project PIs in Tables 3 through 6 does not include reinforcement costs. The anticipated cost of system reinforcement has been included in the calculation of the expected Rolling Portfolio PI set-out in Table 7 and estimated ratepayer impacts, shown in Table 9. The treatment of these costs is consistent with the provisions of EBO 188 in these calculations.

Table 4: Preliminary Profitability Analysis

		Potential Customers			Forecast Customers						
	Community	Conversions	New	Total	Conversions	New	Total	Distance from Source (kms)	Total Investment Pipeline	PI Normal	Proposed Solution
Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Col 7	Col 8	Col 9	Col 10	Col 11	Col 12
1	Fenelon Falls & Bobcaygeon	3,029	3,213	6,242	2,272	3,213	5,485	47	111,956,990	0.26	Pipeline
2	Scugog Island	1,177	291	1,468	883	291	1,174	8	19,714,126	0.24	Pipeline
3	Cambray	400		400	300	0	300	10	7,583,140	0.19	Pipeline
4	Zephyr	250		250	188	0	188	11	5,184,375	0.16	Pipeline
5	Cotnam Island	100		100	75	0	75	10	2,171,890	0.13	Pipeline
6	Sarsfield	200		200	150	0	150	10	4,147,500	0.15	Pipeline
7	Udora	400		400	300	0	300	8	8,842,300	0.16	Pipeline
8	Wilkinson Sub, Innisfil	90		90	68	0	68	2	1,897,055	0.12	Pipeline
9	Town of Marsville	350		350	263	0	263	8	8,047,225	0.16	Pipeline
10	Town of Mansfield	294		294	221	0	221	8	6,817,129	0.15	Pipeline
11	Glendale Subdivision	100		100	75	0	75	6	2,509,250	0.12	Pipeline
12	Caledon - Humber Station	72		72	54	0	54	3	2,067,960	0.10	Pipeline
13	Enniskillen	200		200	150	0	150	10	5,109,500	0.14	Pipeline
14	Village of Lisle	400		400	300	0	300	5	9,966,800	0.15	Pipeline
15	5th Line, Mono Twp.	32		32	24	0	24	3	1,798,760	0.05	Pipeline
16	Sandford	200		200	150	0	150	9	5,590,500	0.13	Pipeline
17	Leasksdale	200		200	150	0	150	8	5,590,500	0.13	Pipeline
18	Curran	100		100	75	0	75	7	3,640,250	0.11	Pipeline
19	Bainsville	100		100	75	0	75	7	3,997,750	0.10	Pipeline
20	Westmeath	200		200	150	0	150	10	6,448,500	0.13	Pipeline
21	Haydon	100		100	75	0	75	10	3,441,281	0.11	LNG
22	Woodville	300		300	225	0	225	9	5,797,180	0.17	LNG
23	South Glengary	200		200	150	0	150	10	4,590,881	0.15	LNG
24	Caledon - Torbram Road	79		79	59	0	59	11	3,117,191	0.10	LNG
25	Chute-a-Blondeau	200		200	150	0	150	10	5,335,501	0.14	LNG
26	Hockley Village, Mono Twp.	64		64	48	0	48	13	2,950,428	0.09	LNG
27	Maxville	400		400	300	0	300	10	7,147,877	0.18	LNG
28	Lanark & Balderson	400		400	300	0	300	12	8,637,117	0.17	LNG
29	Douglas	200		200	150	0	150	20	5,335,501	0.14	LNG
30	Eganville	700		700	525	0	525	40	14,063,487	0.19	LNG
31	Kinburn/Fitzroy Harbour	500		500	375	0	375	15	10,588,874	0.18	LNG
32	St. Isidore	400		400	300	0	300	10	7,147,877	0.18	LNG
33	Kirkfield	800		800	600	0	600	25	15,604,747	0.19	LNG
34	Minden	1,414		1,414	1,061	0	1,061	68	26,418,325	0.20	LNG
35	Coboconk	400		400	300	0	300	40	8,637,117	0.17	LNG
36	Norland	200		200	150	0	150	50	5,335,501	0.14	LNG
37	Barry's Bay	500		500	375	0	375	90	10,761,872	0.17	LNG
38	Kinmount	200		200	150	0	150	60	5,335,501	0.14	LNG
39	Haliburtion (Dysert)	2,035		2,035	1,526	0	1,526	88	37,161,620	0.20	LNG

80. This analysis shows that the normal PIs for these thirty-nine potential community expansion projects range from a low of 0.05 to a high of 0.26, with none of these potential projects having an indicated PI of 0.8 or greater. The estimated capital costs used to determine these PIs shown in Table 4 are based on transmission main for communities assumed to be served through a pipeline option and LNG facilities for those communities where the this option has been identified as a more economical.

81. The main factor leading to the low PIs for these potential projects are high capital costs that are driven by long distances from the existing gas distribution system, difficult terrain and large contingency amounts that have been factored into these estimates. Again, Enbridge expects that once more detailed assessments of the design and construction requirements of these projects are completed and ultimately after this work is tendered the capital cost estimates will be lower.

Table 5: Preliminary Profitability Analysis with Proposed TES and ITE Enhancement

			Potential Customers			Forecast Customers								
	Community	Communities	Conversions	New	Total	Conversions	New	Total	Distance from Source (kms)	Total Investment	PI Normal	PI Proposed	CIAC req'd for PI=0.8	Proposed Solution
Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Col 7	Col 8	Col 9	Col 10	Col 11	Col 12	Col 13	Col 14	Col 15
1	Fenelon Falls & Bobcaygeon	2	3,029	3,213	6,242	2,272	3,213	5,485	47	$111,956,990	0.26	0.70	$10,980,000	Pipeline
2	Scugog Island	1	1,177	291	1,468	883	291	1,174	8	$19,714,126	0.24	0.58	$6,189,863	Pipeline
3	Cambray	1	400		400	300	0	300	10	$7,583,140	0.19	0.45	$3,565,567	Pipeline
4	Zephyr	1	250		250	188	0	188	11	$5,184,375	0.16	0.39	$3,124,677	Pipeline
5	Cotnam Island	1	100		100	75	0	75	10	$2,171,890	0.13	0.36	$1,285,518	Pipeline
6	Sarsfield	1	200		200	150	0	150	10	$4,147,500	0.15	0.38	$2,535,094	Pipeline
7	Udora	1	400		400	300	0	300	8	$8,842,300	0.16	0.37	$5,460,127	Pipeline
8	Wilkinson Sub, Innisfil	1	90		90	68	0	68	2	$1,897,055	0.12	0.35	$1,253,680	Pipeline
9	Town of Marsville	1	350		350	263	0	263	8	$8,047,225	0.16	0.36	$5,102,644	Pipeline
10	Town of Mansfield	1	294		294	221	0	221	8	$6,817,129	0.15	0.36	$4,366,730	Pipeline
11	Glendale Subdivision	1	100		100	75	0	75	6	$2,509,250	0.12	0.31	$1,781,728	Pipeline
12	Caledon - Humber Station	1	72		72	54	0	54	3	$2,067,960	0.10	0.26	$1,594,818	Pipeline
13	Enniskillen	1	200		200	150	0	150	10	$5,109,500	0.14	0.33	$3,497,095	Pipeline
14	Village of Lisle	1	400		400	300	0	300	5	$9,966,800	0.15	0.34	$6,584,626	Pipeline
15	5th Line, Mono Twp.	1	32		32	24	0	24	3	$1,798,760	0.05	0.15	$1,674,004	Pipeline
16	Sandford	1	200		200	150	0	150	9	$5,590,500	0.13	0.31	$3,978,095	Pipeline
17	Leasksdale	1	200		200	150	0	150	8	$5,590,500	0.13	0.31	$3,978,095	Pipeline
18	Curran	1	100		100	75	0	75	7	$3,640,250	0.11	0.25	$2,912,728	Pipeline
19	Bainsville	1	100		100	75	0	75	7	$3,997,750	0.10	0.23	$3,270,228	Pipeline
20	Westmeath	1	200		200	150	0	150	10	$6,448,500	0.13	0.28	$4,836,094	Pipeline
21	Haydon	1	100		100	75	0	75	10	$3,441,281	0.11	0.26	$2,679,802	LNG
22	Woodville	1	300		300	225	0	225	9	$5,797,180	0.17	0.41	$3,602,262	LNG
23	South Glengary	1	200		200	150	0	150	10	$4,590,881	0.15	0.35	$3,114,668	LNG
24	Caledon - Torbram Road	1	79		79	59	0	59	11	$3,117,191	0.10	0.23	$2,512,246	LNG
25	Chute-a-Blondeau	1	200		200	150	0	150	10	$5,335,501	0.14	0.33	$3,511,703	LNG
26	Hockley Village, Mono Twp.	1	64		64	48	0	48	13	$2,950,428	0.09	0.20	$2,451,366	LNG
27	Maxville	1	400		400	300	0	300	10	$7,147,877	0.18	0.44	$4,224,146	LNG
28	Lanark & Balderson	1	400		400	300	0	300	12	$8,637,117	0.17	0.40	$5,018,218	LNG
29	Douglas	1	200		200	150	0	150	20	$5,335,501	0.14	0.33	$3,511,703	LNG
30	Eganville	1	700		700	525	0	525	40	$14,063,487	0.19	0.43	$7,718,759	LNG
31	Kinburn/Fitzroy Harbour	1	500		500	375	0	375	15	$10,588,874	0.18	0.41	$6,051,359	LNG
32	St. Isidore	1	400		400	300	0	300	10	$7,147,877	0.18	0.44	$4,224,146	LNG
33	Kirkfield	1	800		800	600	0	600	25	$15,604,747	0.19	0.44	$8,370,140	LNG
34	Minden	1	1,414		1,414	1,061	0	1,061	68	$26,418,325	0.20	0.46	$13,624,673	LNG
35	Coboconk	1	400		400	300	0	300	40	$8,637,117	0.17	0.40	$5,018,218	LNG
36	Norland	1	200		200	150	0	150	50	$5,335,501	0.14	0.33	$3,511,703	LNG
37	Barry's Bay	1	500		500	375	0	375	90	$10,761,872	0.17	0.41	$6,212,245	LNG
38	Kinmount	1	200		200	150	0	150	60	$5,335,501	0.14	0.33	$3,511,703	LNG
39	Haliburtion (Dysert)	1	2,035		2,035	1,526	0	1,526	88	$37,161,620	0.20	0.47	$18,762,625	LNG

82. Table 5 expands upon the information provided in Table 4 by adding the "Proposed PI" and the calculated Contribution in Aid of Construction ("CIAC") required in order to bring the PIs of these potential projects up to 0.8. The Proposed PIs include the impact of the additional financial support provided by the implementation of the SES and the ITE. Based on the Company's current cost estimates fourteen projects achieve PIs greater than or equal to 0.4. However, only three potential projects achieve a PI of 0.4 or greater under the Company's proposal when the cost of transmission mains is included in the analysis for all projects. It can also be seen that in some cases significant additional financial support would be required in order to achieve PIs of 0.8 as set-out in EBO 188.

83. As noted earlier, the Company has also identified a subset of communities that could potentially be more economically served through the utilization of LNG as an alternate means of transporting natural gas to these locations. This analysis indicates that in cases where the capital cost of transmission main to connect these communities to the Company's existing natural gas distribution system

constitutes a disproportionate amount of the total project cost LNG may provide a more economically attractive solution.

84. In order to test the LNG option for each potential project the Company eliminated the estimated capital cost for transmission main necessary to serve these communities. These costs were replaced with the estimated capital cost of the required LNG decanting, odorization and injection facilities required to transition the LNG back into a gaseous state so that it could then be delivered to customers via a typical natural gas distribution system. For the purpose of this exercise it has been assumed that Enbridge would acquire the LNG supply from a third party and contract to have the LNG delivered to the LNG served communities on a regular basis.

85. In a number of cases the LNG alternative results in a lower capital cost and in turn a more favourable indicated project PI, however, in assessing the overall economics of the LNG alternative the benefit of the reduced capital spending must be considered in addition to the additional cost associated with LNG supply.

86. Implicit in this approach is the understanding that the cost of the LNG required to serve such communities would be recovered from all customers through the Company's gas supply plan.

Table 6: LNG Costing Scenario

				Pipeline Solution			LNG Solution						
	Community	Potential Customers	Distance from Source (kms)	Required Investment (pipeline)	PI Proposed (Pipeline)	Annual Capital Subsidy with Pipeline	Required Investment (LNG)	Proposed PI (LNG)	Annual Capital Subsidy with LNG	Gas Cost Subsidy with LNG	Total Annual Subsidy with LNG	Cross Subsidy Pipeline vs LNG	Proposed Solution
Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Col 7	Col 8	Col 9	Col 10	Col 11	Col 12	Col 13	Col 14
1	Fenelon Falls & Bobcaygeon	6,242	47	$111,956,990	0.70	$2,200,986	$85,868,692	0.93	$473,884	$6,770,050	$7,243,934	($5,042,949)	Pipeline
2	Scugog Island	1,468	8	$19,714,126	0.58	$582,870	$19,849,630	0.58	$591,415	$985,950	$1,577,365	($994,495)	Pipeline
3	Cambray	400	10	$7,583,140	0.45	$273,798	$8,637,117	0.40	$340,260	$252,000	$592,260	($318,462)	Pipeline
4	Zephyr	250	11	$5,184,375	0.39	$227,009	$5,365,852	0.38	$238,453	$157,500	$395,953	($168,944)	Pipeline
5	Cotnam Island	100	10	$2,171,890	0.36	$91,641	$3,813,591	0.25	$195,165	$63,000	$258,165	($166,523)	Pipeline
6	Sarsfield	200	10	$4,147,500	0.38	$183,231	$4,590,881	0.35	$211,190	$126,000	$337,190	($153,959)	Pipeline
7	Udora	400	8	$8,842,300	0.37	$393,267	$7,147,877	0.44	$286,418	$252,000	$538,418	($145,152)	Pipeline
8	Wilkinson Sub, Innisfil	90	2	$1,897,055	0.35	$88,543	$3,290,963	0.25	$176,441	$56,700	$233,141	($144,598)	Pipeline
9	Town of Marsville	350	8	$8,047,225	0.36	$364,530	$6,577,702	0.42	$271,864	$220,500	$492,364	($127,834)	Pipeline
10	Town of Mansfield	294	8	$6,817,129	0.36	$310,997	$5,814,559	0.40	$247,777	$185,220	$432,997	($121,999)	Pipeline
11	Glendale Subdivision	100	6	$2,509,250	0.31	$122,931	$3,441,281	0.26	$181,704	$63,000	$244,704	($121,773)	Pipeline
12	Caledon - Humber Station	72	3	$2,067,960	0.26	$107,286	$3,039,368	0.21	$168,542	$45,360	$213,902	($106,616)	Pipeline
13	Enniskillen	200	10	$5,109,500	0.33	$243,894	$4,590,881	0.35	$211,190	$126,000	$337,190	($93,297)	Pipeline
14	Village of Lisle	400	5	$9,966,800	0.34	$464,176	$7,262,277	0.43	$293,632	$252,000	$545,632	($81,456)	Pipeline
15	5th Line, Mono Twp.	32	3	$1,798,760	0.15	$107,404	$2,594,668	0.14	$157,593	$20,160	$177,753	($70,349)	Pipeline
16	Sandford	200	9	$5,590,500	0.31	$274,225	$4,590,881	0.35	$211,190	$126,000	$337,190	($62,965)	Pipeline
17	Leasksdale	200	8	$5,590,500	0.31	$274,225	$4,590,881	0.35	$211,190	$126,000	$337,190	($62,965)	Pipeline
18	Curran	100	7	$3,640,250	0.25	$194,251	$3,441,281	0.26	$181,704	$63,000	$244,704	($50,453)	Pipeline
19	Bainsville	100	7	$3,997,750	0.23	$216,794	$3,441,281	0.26	$181,704	$63,000	$244,704	($27,910)	Pipeline
20	Westmeath	200	10	$6,448,500	0.28	$328,329	$4,590,881	0.35	$211,190	$126,000	$337,190	($8,861)	Pipeline
21	Haydon	100	10	$4,478,750	0.22	$247,126	$3,441,281	0.26	$181,704	$63,000	$244,704	$2,421	LNG
22	Woodville	300	9	$9,290,550	0.30	$464,539	$5,797,180	0.41	$244,251	$189,000	$433,251	$31,287	LNG
23	South Glengary	200	10	$8,203,500	0.24	$438,997	$4,590,881	0.35	$211,190	$126,000	$337,190	$101,807	LNG
24	Caledon - Torbram Road	79	11	$6,169,283	0.17	$362,804	$3,117,191	0.23	$170,343	$49,770	$220,113	$142,691	LNG
25	Chute-a-Blondeau	200	10	$9,634,780	0.23	$509,218	$5,335,501	0.33	$238,111	$126,000	$364,111	$145,107	LNG
26	Hockley Village, Mono Twp.	64	13	$6,204,020	0.15	$371,382	$2,950,428	0.20	$166,215	$40,320	$206,535	$164,847	LNG
27	Maxville	400	10	$14,727,400	0.27	$764,373	$7,147,877	0.44	$286,418	$252,000	$538,418	$225,955	LNG
28	Lanark & Balderson	400	12	$16,337,800	0.26	$825,855	$8,637,117	0.40	$340,260	$252,000	$592,260	$233,595	LNG
29	Douglas	200	20	$12,369,720	0.20	$681,680	$5,335,501	0.33	$238,111	$126,000	$364,111	$317,569	LNG
30	Eganville	700	40	$26,853,960	0.27	$1,329,921	$14,063,487	0.43	$523,371	$441,000	$964,371	$365,551	LNG
31	Kinburn/Fitzroy Harbour	500	15	$22,175,820	0.25	$1,140,970	$10,588,874	0.41	$410,313	$315,000	$725,313	$415,658	LNG
32	St. Isidore	400	10	$18,315,400	0.24	$990,628	$7,147,877	0.44	$286,418	$252,000	$538,418	$452,209	LNG
33	Kirkfield	800	25	$38,400,280	0.24	$2,004,994	$15,604,747	0.44	$567,538	$504,000	$1,071,538	$933,456	LNG
34	Minden	1,414	68	$78,108,620	0.22	$4,183,344	$26,418,325	0.46	$923,821	$891,000	$1,814,821	$2,368,522	LNG
35	Coboconk	400	40	$39,174,640	0.17	$2,265,917	$8,637,117	0.40	$340,260	$252,000	$592,260	$1,673,656	LNG
36	Norland	200	50	$44,373,120	0.13	$2,699,772	$5,335,501	0.33	$238,111	$126,000	$364,111	$2,335,661	LNG
37	Barry's Bay	500	90	$71,120,300	0.15	$4,227,345	$10,761,872	0.41	$421,221	$315,000	$736,221	$3,491,123	LNG
38	Kinmount	200	60	$52,654,120	0.13	$3,221,961	$5,335,501	0.33	$238,111	$126,000	$364,111	$2,857,850	LNG
39	Haliburtion (Dysert)	2,035	88	$104,815,526	0.23	$5,538,366	$37,161,620	0.47	$1,272,200	$1,281,893	$2,554,093	$2,984,273	LNG

87. The figures in Column 7 of Table 6 represent the value of the annual ratepayer subsidy for each community expansion project assuming transmission main supply. Column 10 shows the ratepayer subsidy with respect to capital costs for all of the projects assuming LNG supply (all transmission main capital cost removed and the estimated cost of the required LNG decanting facility for each project added).

88. As expected the reduced capital cost of the LNG alternative leads to reduced ratepayer subsidies and higher PIs for this option compared to the pipeline supply alternative when only capital costs are considered. However, to complete this comparison it is necessary to add in the incremental cost of the LNG supply which Enbridge proposes to recover from all customers. The figures in Column 11 represent the estimated incremental cost of LNG supply and Column 12 shows the total subsidy associated with each project assuming LNG Supply. Column 13 shows the net difference in the subsidy value between the two alternatives.

89. Based on the Company's analysis it is estimated that it would be more economical to serve nineteen of these communities with the LNG alternative. In actuality, it will not be possible to definitely determine which community expansion projects are best served by the LNG option until more detailed project and LNG costing can be completed. The Company proposes that in cases where the economic advantage of LNG supply can be confirmed, that should be identified in the leave to construct applications specific to these particular community expansion projects. Implicit in this approach is the understanding that the incremental cost of the LNG as compared to the normal cost of system supply required to serve these communities would be included in the Company's rates and recovered from all customers in the same manner as the Company's gas supply plan. Again, this analysis also assumes that the projects to serve these communities roll out over a nine year period as previously indicated.

Table 7: Rolling Portfolio Including the Potential Forty Community Expansion Projects

Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Col 7	Col 8	Col 9
	Year 1 ($million)	Year 2 ($million)	Year 3 ($million)	Year 4 ($million)	Year 5 ($million)	Year 6 ($million)	Year 7 ($million)	Year 8 ($million)
Typical RPP								
(Recent 3 years' average)								
Inflow	111	111	111	111	111	111	111	111
Outflow	(71)	(71)	(71)	(71)	(71)	(71)	(71)	(71)
NPV	40	40	40	40	40	40	40	40
Profitability Index	1.56	1.56	1.56	1.56	1.56	1.56	1.56	1.56
Cash Flow of 39 Projects								
Inflow	91	15	10	12	9	12	24	59
Outflow	(154)	(34)	(22)	(28)	(25)	(41)	(49)	(115)
NPV	(63)	(19)	(12)	(16)	(15)	(28)	(25)	(56)
Profitability Index	0.59	0.44	0.46	0.42	0.38	0.30	0.49	0.52
Impact on RPP								
Inflow	202	126	121	123	120	123	135	170
Outflow	(225)	(105)	(93)	(99)	(96)	(112)	(120)	(186)
NPV	(23)	21	28	24	25	12	15	(16)
Profitability Index	**0.90**	**1.20**	**1.30**	**1.24**	**1.26**	**1.10**	**1.13**	**0.92**

90. One of the measures required by EBO 188 is the PI of the RPP. This calculation takes into account that in the early years after the completion of a project the costs generally exceed the revenues and that there is a greater impact on rates than in the later years when revenues generally exceed costs. This provision of EBO 188 requires the Company to maintain a twelve month RPP PI of 1.0 or greater for current system expansion projects, excluding customers requiring only a service lateral from an existing main. This measure is intended to ensure that existing ratepayers are not negatively impacted by new projects while assisting

communities to obtain gas service where otherwise it would not be financially feasible on a stand-alone basis.

91. The IP includes all capital costs of facilities for all new customers added during a test year including the cost of system reinforcement projects and the costs associated with adding customers to existing mains. The primary purpose of the IP test is to provide the Board with information to confirm that a utility's overall system expansion plan will not result in undue rate impacts, rather than limiting this view to only system expansion projects.

Table 8: Investment Portfolio Including Phase 1 (the first two) of the Potential Thirty-Nine Community Expansion Projects

Col 1	Col 2	Col 3	Col 4	Col 5
	Inflow	Outflow	PI	NPV
	($million)	($million)		($million)
2016 IP Forecast (proxy for 2017)	168	152	1.11	16
Community Expansion forecast for 2017	8	58	0.14	(50)
Impact on Investment Portfolio	177	210	0.84	(34)

92. Table 8 illustrates the expected impact on the Profitability Index of the IP in the first year assuming that the anticipated community expansion projects identified in Table 5 are in service in the time frame noted earlier. The analysis assumes that the indicated total annual revenue requirement includes various cost elements including cost of capital, cost of service and income tax. Commodity and other upstream costs are not included in revenue requirement calculations.

93. Without the proposed exemptions from EBO 188 concerning the inclusion of the CEP projects from the calculation of the RPP and IP these projects will not be able to go forward. As indicated above the RPP PI is expected to drop below the EBO 188 minimum prescribed level of 1.0 and in the case of the IP the indicated PI is expected to drop to 0.84 from a status quo value of 1.11, again a level that would be below 1.0, the minimum PI level prescribed in the EBO 188 Report.

94. Enbridge agrees with Union Gas that rather than focusing on the PIs of each company's IP and RPP a more appropriate approach would be to give consideration to the impact on existing customers of each company's proposal,

given the desire of the province to make the extension of gas service to currently unserved communities more viable.

Table 9: Projected Ratepayer Impact Assuming all of the Potential Thirty Nine Community Expansion Projects are Undertaken

Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Col 7	Col 8	Col 9	Col 10	Col 11	Col 12
Line	New customers' attachment profile	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10
1	Residential	1,219	1,259	1,508	1,786	1,400	1,330	2,153	4,343	228	214
2	Commercial	73	121	93	84	51	54	95	220	8	6
3	Industrial	1									
	Total customers	1,293	1,380	1,601	1,870	1,451	1,384	2,247	4,563	236	220
		($million)	($million)	($million)	($million)	($million)	($million)	($million)	($million)	($million)	($million)
4	Capital Investment	56.77	57.70	56.28	43.75	31.12	46.11	51.68	117.59	1.42	1.25
	Volume Build up	(10^6 m^3)	(10^6 m^3)	(10^6 m^3)	(10^6 m^3)	(10^6 m^3)	(10^6 m^3)	(10^6 m^3)	(10^6 m^3)	(10^6 m^3)	(10^6 m^3)
5	R1 (Residential)	1.5	4.4	7.8	11.7	15.5	18.8	23.0	30.8	36.3	36.8
6	R6 (Com/Ind)	0.8	2.8	5.1	7.0	8.2	9.1	10.1	11.7	12.9	13.0
		2.2	7.3	12.9	18.7	23.7	27.9	33.0	42.5	49.1	49.8
	Revenue requirement	($million)	($million)	($million)	($million)	($million)	($million)	($million)	($million)	($million)	($million)
7	Revenue requirement	2.52	7.57	12.55	16.91	20.12	23.40	27.56	34.91	39.93	39.70
8	- Less: revenue from new customers	0.80	2.58	4.58	6.66	8.52	10.07	12.00	15.57	18.11	18.35
9	Incremental revenue requirement (Inc. RR)	1.72	4.99	7.98	10.24	11.60	13.33	15.57	19.33	21.83	21.35
	Bill impact -residential customers	($million)	($million)	($million)	($million)	($million)	($million)	($million)	($million)	($million)	($million)
10	Increase in Rev Req for R1 customers	1.09	2.67	5.29	7.46	8.92	9.76	11.11	13.02	21.09	20.77
11	Year-over-year change in RR	1.09	1.58	2.61	2.17	1.47	0.83	1.35	1.91	8.07	(0.32)
12	Total residential throughput (106 m3)	4,869	4,869	4,869	4,869	4,869	4,869	4,869	4,869	4,869	4,869
13	Unit rate impact - residential ($/m3)	0.0002	0.0003	0.0005	0.0004	0.0003	0.0002	0.0003	0.0004	0.0017	-0.0001
14	Annual average use - residential (m3)	2400	2400	2400	2400	2400	2400	2400	2400	2400	2400
15	Year-over-year bill increase	$0.54	$0.78	$1.29	$1.07	$0.72	$0.41	$0.67	$0.94	$3.98	($0.16)
	Gas cost impact										
16	Year-over-year increase in LNG cost					$0.12	$0.17	$0.39	$1.04	$0.00	$0.00

95. Table 9 shows the estimated ratepayer impacts associated with the Company's proposal over the first ten years assuming that the contemplated projects go into service as anticipated in this analysis. Line 15 of the table displays the expected year-over-year impact on the average customer bill stemming from the adoption of the Enbridge proposal assuming the projects go ahead. Over this period of time the year-over-year changes range from a rate reduction of $0.16 to a rate increase of $3.98. On a cumulative basis the impact on the average customer's bill would reach its maximum level in the ninth year at $10.39 and then begin to slowly decline. Even when the forecast cost of funding incremental supplies of LNG is included in the analysis, the maximum cumulative average impact on an existing customer is limited to about $1.00 per month at an annual level of $12.11.

Table 10: Other Public Interest Factors Including Stage 2 Benefits for New Customers

Col 1	Col 2	Col 3
Stage 1 Benefits: Based on project cash flows		**NPV**
Stage 1 NPV (at social discount rate = 4%)	A	(122,702,977)
Stage 2 Benefits: Based on Customers' cash flows		
Energy cost savings		384,495,523
Less: Conversion costs		(27,418,920)
Stage 2 Benefits (NPV)	B	357,076,603
Combined benefits (Stage 1 + Stage 2)	A+B	234,373,626

96. In the absence of any contribution in aid of construction the Community Expansion Portfolio produces a negative NPV of utility cash flows (Stage 1 analysis) of approximately $123 million. A social discount rate of 4% was used for these calculations.

97. A Stage 2 assessment was also done to evaluate new customer benefits for switching to natural gas at significantly lower retail rates than competitive fuels. The customers' cost of natural gas was compared to the cost of either propane or fuel oil or electricity and any savings are netted against the conversion costs. The net savings are then discounted at a social discount rate to produce an NPV of customer cash flows. The resulting NPV of customers' net fuel savings from this Stage 2 assessment for all 39 projects is approximately $357 million.

98. In a Cap and Trade (C&T) environment those using electricity for heating and water heating are expected to have lower exposure to the cost of carbon compared to those using natural gas, propane or heating oil for the purpose of heating and water heating. A revised Stage 2 analysis based on information provided in the Province's 2016 Budget indicates that under a C&T environment it would be expected that there would be a modest reduction in Stage 2 benefits reducing them to $351 million from the figure noted in Table 10.

99. The analysis summarized in Table 10 shows that in combination Stage 1 and Stage 2 benefits result in a total quantifiable public interest benefit of approximately $234 million. The revised Stage 2 benefit analysis indicates that the combined Stage 1 and Stage 2 benefit under a C&T environment would be reduced to $228 million.

Conclusion

100. In the procedural order pertaining to this proceeding the Board identified twelve issues that it sought to address through this proceeding. In this evidence Enbridge has responded to each of these issues and brought forward a proposal that answers many of the questions raised by the Board in connection with these issues.

101. With respect to the second and third issues the Company does not believe that the Board has the jurisdiction to establish a framework whereby the customers of one utility subsidize the expansion undertaken by another distributor. Beyond the purely legal question, in almost all respects this concept ignores many of the fundamental tenants of rate making for regulated utilities and would dilute the economies of scale that have developed over long periods of time in the incumbent service providers. With respect to economies of scale, the concept has apparently been acknowledged by the Province as it relates to the electricity sector where actions have been recently taken to promote the consolidation of local electricity distribution companies.

102. The fourth issue raised by the Board seeks to identify potential exemptions or revisions to the EBO 188 Guideline for rural and remote community expansion projects. The Enbridge proposal outlines several changes that could be made to the existing EBO 188 Guidelines that would enable the Company to pursue community expansion projects that currently do not meet the Board's current minimum economic criteria. In the Company's view its proposal recognizes the importance of finding a reasonable economic balance between the interests of those individuals residing in these communities and the need to not place an undue burden on existing customers.

103. Issue five asks whether or not the existing gas distribution companies should be able to establish surcharges applicable to those customers that are served by natural gas community expansion projects and the sixth issue asks if there are other ratemaking approaches that the Board could consider. Again, the Company's proposal addresses these questions by proposing a surcharge that enables those served by community expansion projects to contribute toward the cost of these projects beyond what would be recovered in base rates. The proposal also

describes how this additional revenue can be applied to lessen the impact of community expansion projects on existing customers.

104. With respect to issue seven, the capital costs associated with the potential community expansion projects identified in this document are not included in the Company's current incentive rate model cost base. Y-factor treatment of these costs will make it possible for Enbridge to commit the capital required to pursue these community expansion projects in the current incentive rate model and in future rate setting regimes. This issue is also addressed in the Enbridge proposal.

105. In its Filing Guidelines on the Economic Tests for Transmission Pipeline Applications in EB-2012-0092 the Board stated *"The Board continues to hold the opinion that it is appropriate for existing customers to subsidize, through higher rates, financially non-sustaining extensions that are in the overall public interest if the subsidy does not cause an undue burden on any individual, group or class."*

106. For much of the time the EBO 188 Guidelines have been in place they allowed the Ontario natural gas distribution utilities to expand service to outlying communities on the periphery of their systems in an economic way that limited rate impacts on the existing customer base of these companies. In recent years the interplay between the EBO 188 Guidelines and other physical, economic and administrative factors have combined to constrain the expansion of the Province's natural gas distribution networks to unserved communities.

107. Those communities that remain without natural gas distribution service today are typically distant from the existing gas distribution systems, have relatively low numbers of potential customers and in many cases are found in locations where the nature of the terrain gives rise to high construction costs. These challenges have further limited the ability of Ontario natural gas distributors to expand gas services to these locations.

108. On average the customers that attach to the Company's distribution system in these communities will benefit economically while also contributing to the cost of service associated with these areas through the implementation of a higher rate in the form of a surcharge. The burden on existing customers will be limited and managed by maintaining the PI of the CEP at or above a minimum level. The

overall economic benefit of this proposal is borne out by the Stage 2 assessment that is presented in this evidence.

109. In the Company's view it has presented the Board with an innovative proposal that addresses the issues identified by the Board in its EB-2016-004 issues list. The Company's proposal recognizes that where appropriate LNG is a potentially more economical means of extending service to more remotely located communities as an alternative to the construction of traditional transmission mains and attempts to strike a reasonable balance between the interests of existing customers and those potential customers located in remote communities.

110. Through the correspondence that has given rise to this proceeding the Province has indicated that it recognizes the economic and social benefits of extending gas services to many of these unserved communities. Enbridge is of the view that the proposal that it has put forward in this evidence meets the objective of enabling the further expansion of the province's natural gas distribution system to many currently unserved communities while striking a reasonable balance between the interests of the potential customers that now reside in these communities and the Company's current customer base.

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February 18, 2015

To: All Applicants and Potential Applicants for Expansion of Natural Gas Distribution

Re: Expansion of Natural Gas Distribution

The Provincial Government has set out a goal of ensuring that Ontario consumers in communities that currently do not have access to natural gas are able to share in affordable supplies of natural gas. In an effort to facilitate enhanced access to natural gas for rural and remote communities and businesses in the province, the Ontario Energy Board (the "Board") is inviting parties with the appropriate financial and technical expertise to propose one or more plans for natural gas expansion.

In this context and depending on the nature and scope of any proposals made, the Board is aware that regulatory flexibility may be required. The Board will hear requests for regulatory flexibility or appropriate exemptions in the context of an application made for approvals pertaining to expansion portfolios and specific projects.

Background

In the Long Term Energy Plan the Ontario Government signaled that it would look at opportunities to expand natural gas service within the Province to areas that are not currently served. In support of this objective, the Government, through the Minister of Economic Development, Employment and Infrastructure, will be making available;

- $200 million in Natural Gas Access Loans over two years to help communities partner with utilities to extend access to natural gas, and
- $30 million in "Natural Gas Economic Development Grants" to accelerate projects with clear economic development potential.

In 1998, the Board established guidelines for the expansion of natural gas service in its *EBO 188 Report on Natural Gas Distribution System Expansion* (EBO 188). The intent of EBO 188 is to facilitate the expansion of natural gas service while holding other customers harmless from the cost of new connections.

EBO 188 adopts a portfolio approach for gas expansion/connections, which requires distributors to design a portfolio of projects that will achieve an overall profitability index (PI) of 1. This means that over the life of the projects within the portfolio, connected customers will pay the entire costs (through rates and a capital contribution if required). EBO 188 also specifies that any one individual expansion project within a portfolio or otherwise must meet a PI of 0.8. This requirement is intended to minimize cross-subsidization across customers within a portfolio.

While minimizing cross-subsidization either within a portfolio of projects, or between a portfolio and the rest of Ontario customers remains an important goal, the Board is cognizant that the specific requirements of EBO 188 may require some flexibility to expand access to natural gas for communities that are not currently served.

The Board's Approach

To the extent that the economics of a proposed project may not be accommodated within the current regulatory construct, the Board invites proponents to identify, within their applications, any options to address such regulatory issues. The Board will consider any such options as part of its adjudicative process. For instance, the Board may consider specific and supportable proposals that address;

- Whether the Board should allow existing natural gas distributors to establish surcharges to improve the feasibility of potential expansion projects by minimizing the level of required capital contribution.
- Whether the Board should allow for recovery of the revenue requirement associated with expansion costs in rates prior to the end of any incentive regulation plan term once the assets are used and useful.
- Whether projects that have a portfolio PI less than 1.0 and individual projects within a portfolio that have a PI lower than 0.8 should be considered.

Applicants should take the following into consideration when filing their application:

- Where no certificate of public convenience and necessity has been previously granted in a particular area, applications will be considered from all proponents with the requisite financial and technical expertise and experience.

- Proponents should develop proposals that, while ensuring safety and reliability, are cost effective and incorporate flexibility with respect to cost recovery (e.g. ROE, depreciation period, recovery of capital contribution, etc.).

- Proponents should develop proposals that include measures that foster predictability and cost certainty from a consumer perspective.

- Proponents should develop proposals that minimize impacts on existing natural gas ratepayers as a result of new expansion projects.

The Board is considering the need and manner in which to provide clarity for municipalities and potential new service providers on the processes needed to be taken to expand access to natural gas and will communicate further on this.

Invitation to Submit Application

The Board encourages parties interested in distributing natural gas to unserved rural and remote communities to submit an application seeking one or more required approvals (e.g. certificate of public convenience and necessity, franchise agreement, leave to construct) for the Board's consideration.

Subsequent to any Board approval of the above applications, a company would be required to apply to the Board for an order approving just and reasonable rates for the sale of gas and provisions of gas distribution services.

A summary of the requisite approvals is found under Appendix A of this letter.

Any questions relating to this letter should be directed to **Jason Craig** at **jason.craig@ontarioenergyboard.ca** **at** 416-440-8139. The Board’s toll-free number is 1-888-632-6273.

Yours truly,

Original Signed By

Peter Fraser
Vice President, Industry Operation Performance

Appendix – A
Description of Approvals

Certificate of Public Convenience and Necessity

In order to provide natural gas distribution services to consumers in Ontario, a company must apply to the Board for a certificate of public convenience and necessity for the service territory that is to be served.

The certificate of public convenience and necessity grants the gas distributor the right to construct infrastructure for the purposes of supplying gas to consumers in the service territory specified.

Numerous examples of certificate of public convenience and necessity applications can be found on the Board's website.

Franchise Agreement

In order to provide natural gas distribution services to consumers in Ontario, a company must also enter into a municipal franchise agreement with a municipality. The municipal franchise agreement is signed by both the municipality that is agreeing to be served and the distribution company.

The Board has the authority to approve the municipal franchise agreement. The municipal franchise agreement sets out the right for a natural gas distributor to operate works and add to works for the distribution of gas within the boundaries of a municipality.

In 2000, a Model Franchise Agreement ("MFA") was developed for use across the province.

The MFA sets out the obligations of the gas distributor in regard to the technical, construction, safety, and operational aspects of the natural gas distribution system within the municipality. The terms of the MFA ensure coordination between the municipality and the utility with regards to construction, operation and maintenance of the system. The standard term of the MFA is 20 years.

The model franchise agreement and examples of franchise agreement applications can be found on the Board's website.

Leave to Construct

Any company planning to build a distribution system in Ontario must apply to the Board for leave to construct if the proposed pipeline:

a) is greater than 20 kilometres in length;
b) is estimated to cost more than the amount prescribed by certain regulations (currently $2 million); or
c) uses pipe that has a nominal pipe size of 12 inches or more and has an operating pressure of 2,000 kilopascals or more.

Application may also be made to the Board to expropriate the land rights necessary to build the pipeline (and related infrastructure) once leave to construct is granted.

Leave to construct applications typically provide: a project summary, information regarding the need for the proposed project, facility planning information, the projected costs of the project and other economic, engineering, and environmental information (including detailed environmental reports), and the land requirements for the project (including plans for informing and negotiating with impacted landowners).

The Board's *Environmental Guidelines for the Location, Construction and Operation of Hydrocarbon Pipelines and Facilities in Ontario* provides detailed information regarding the planning requirements for locating new facilities, the mitigation measures required for pipeline (and related facility) construction and the process for review and approval of environmental reports. These guidelines can be found on the Board's website: http://www.ontarioenergyboard.ca/oeb/_Documents/Regulatory/Enviro_Guidelines_HydrocarbonPipelines_2011.pdf.

Numerous examples of leave to construct applications and the associated Board decisions on those applications can be found on the Board's website.