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Our File No. 161734

June 20, 2016

VIA EMAIL, RESS AND COURIER

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

Attention: Kirsten Walli,
Board Secretary

Dear Ms. Walli:

Re: EB-2016-0004: BOMA's Submission

Pursuant to Procedural Order No. 3, please find enclosed BOMA's Submission.

Yours truly,

FOGLER, RUBINOFF LLP

Tom Brett

Thomas Brett
TB/dd
Encls.
cc: All Parties *(by email)*

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EB-2016-0004

ONTARIO ENERGY BOARD

IN THE MATTER OF the Ontario Energy Board Act, 1998, S.O. 1998, c. 15, Sch. B, as amended;

AND IN THE MATTER OF a Generic Proceeding on Natural Gas Expansion in Communities that are not served.

SUBMISSION OF

BUILDING OWNERS AND MANAGERS ASSOCIATION, GREATER TORONTO ("BOMA")

June 20, 2016

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Counsel for BOMA

Submission

Introduction

In Procedural Order No. 3, the Board advised that the Issues List and the Board's Decision dated May 2, 2016, Decision on Incomplete Interrogatory Responses (Decision) should be the primary guidance for scoping the arguments. They also asked for additional comments on certain matters.

BOMA will deal with the Issues List and the Decision first, then will deal with each matter on which the Board asked for additional submissions.

Issue 2

The Board framed its legal question as follows:

> "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?"

BOMA is of the view that utility rates which included amounts to be used for such a purpose would contravene section 36 of the Ontario Energy Board Act (the "Act"). Accordingly, a framework, or policy, which purported to authorize such rates is beyond the jurisdiction of the Board.

Section 36(2) permits the Board to:

> "make orders approving or fixing just and reasonable rates for the sale of gas by gas transmitters, gas distributors and storage companies, and for the transmission, distribution and storage of gas".

BOMA believes distribution rates which included an amount to be paid to customers of another gas utility or to that other utility's potential customers to subsidize that utility's expansion into communities that do not have natural gas service, would not be just and reasonable, and therefore, cannot be ordered by the Board.

Section 36(3) provides that:

> "In approving or fixing just and reasonable rates, the Board may adopt any method or technique that it considers appropriate".

BOMA believes that this provision allows the Board to, for example, set rates based on a cost of service basis, or an incentive rate-making basis, and they have done both, or to use a future or historic test year. However, Section 36(3) assumes that the rates, whatever method is used to set them, must remain just and reasonable. To remain just and reasonable, the rates, inter alia, must be for the purpose of operating and growing the utility that charges them, and linked in some fashion to its overall costs, and be in return for services provided to <u>its</u> customers (our emphasis).

Regulators and the supervisory courts have interpreted just and reasonable rates to mean rates that fairly balance the interests of ratepayers in having rates as low as practicable, while at the same time permitting the utility to be financial viable, in other words, to have the opportunity to earn a compensatory return for its shareholders after paying its operating costs, borrowing costs, and taxes, and to grow its business. Just and reasonable rates have never, to BOMA's knowledge, included amounts to be paid to subsidize the expansion of another utility into an area currently not served by natural gas. KPMG, in its study of practices in different jurisdictions for the OEB, reported that it found no case where such a subsidy was in effect [Exhibit 8, Tab 8, Page 6].

This formulation of what constitutes just and reasonable rates means that such rates must generally reflect the utility's costs, provided that those costs are reasonable and prudently incurred. Under the prudence doctrine, regulators can deny a utility recovery in rates of costs which it decides were the result of imprudent decisions of the utility, including costs that a utility incurred despite earlier warnings by the regulator that it should take steps to reduce that category of costs. This approach has been recently confirmed by the Supreme Court of Canada in Ontario (Energy Board) v. Ontario Power Generation Inc., 2015 SCC 44.

Section 36(4) of the Act states that:

> "An order under this section may include conditions, classifications or practices applicable to the sale, transmission, distribution or storage of gas, including rules respecting the calculation of rates".

This section allows the Board to, for example, set different rates for different classes, use different fixed/variable structures in rates, and utilize rate riders and other mechanism, such as deferral accounts. But again, the rates must remain just and reasonable.

Section 36(6) states it is the distributor (applicant) that must bear the burden of satisfying the Board that rates it applies for are just and reasonable, whether the applicant itself seeks new rates, or whether the Board commences a proceeding to review a utility's rates of its own motion, or upon the request of the Minister.

Section 42(2) of the Act requires a gas distributor, subject to certain provisions in the Public Utilities Act, the Technical Standards and Safety Act, and the Municipal Act/City of Toronto Act, to:

> "...provide gas distribution services to any building along the line of any of the gas distributor's distribution pipe lines upon the request in writing of the owner, occupant or other person in charge of the building. 2006, c. 32, Sched. C, s. 42".

However, gas utilities are not obliged to expand willy-nilly into parts of Ontario that are currently unserved and, unlike in some other jurisdictions, the Board does not have the authority to order a utility to expand into an unserved area. The Board currently has a policy in place (EBO-188) which requires a distributor seeking to expand its system to demonstrate that it meets an economic test to ensure no long-term cross-subsidization of the expansion customers by its existing customers. Given that the Board does not have the authority to order a gas utility to expand into unserved areas, it would follow that it does not have the authority to require that same utility to subsidize another utility to do so.

Issue 4

EBO-188

In BOMA's view, the OEB should not make changes to, or grant exemptions from, EBO-188 for rural or remote community expansion projects.

EBO-188 has been in effect since 1995. It was put in place only after lengthy and detailed proceedings which included a wide spectrum of parties. It included two sets of submissions, an interim report, a settlement conference, and a final report, over a two year period. Its purpose is to ensure that gas utility distribution expansion projects must be economic in the sense that the expansion projects as a group, taking into account their forecast costs and revenues over a forty year life would not require a subsidy from existing ratepayers to proceed. EBO-188 requires the utilities to maintain a rolling project portfolio profitability index of 1.0, for all its expansion projects over the previous twelve months. The twelve month period is rolling in that every month a new month is added and the first month is dropped off. The portfolio approach allows the utility to apply the profitability test to the portfolio of expansion projects, so that the economically stronger projects can carry the weaker ones. In this manner, it provides the utility some flexibility to pursue some expansion projects that, taken in isolation, would not be economic. For any twelve month period, the profitability index of the portfolio must be at least 1.0, or put another way, the weighted average of the net present value of the projects' costs and revenues discounted at the utility's weighted average cost of capital (WACC) over their lives must be greater than zero. It is generally understood that in the early years of an economic project, its forecast costs will exceed the revenues it generates, but that temporary shortfall would be offset in later years when the forecast revenues from the project exceed forecast project costs. In other words, over the project's forty year life, when forecast costs, both capital and operating, and revenues are discounted at the EBO-188 prescribed discount rate, which is the utility's weighted average cost of capital, the revenue will be at least equal to the costs, which yields a project profitability index of 1.0. EBO-188 allows a few individual projects to proceed with a forecasted P/I as low as 0.8 (no lower), provided that the implementation of those projects would not cause the rolling portfolio P/I to fall below 1.0. In the event a project does not meet the 0.8 threshold and the utility still wishes to proceed, the utility will require a Contribution-in-Aid of Construction (CIAC) from the project's soon to-be-connected customers or some other source to bring the utility's own costs down to the point when the project's P/I meets the 0.8 threshold. The CIAC reduces the utility's rate base and its revenue requirement.

In order to continuously meet the rolling project portfolio P/I of 1.0 for expansion projects over the previous twelve months, projects with P/Is of between 0.8 and 1.0 will need to be offset by projects with a P/I of greater than one. To reiterate, the portfolio approach allows the utilities to take on some expansion projects that are uneconomic, that is, have a profitability index of less than 1.0, provided the rolling P/I of the portfolio is at least 1.0.

EBO-188 prescribes a second test, complementary to the rolling project portfolio profitability 1.0 index. The investment portfolio test requires that for any given test year, the forecast distribution expansion capital expenditures incurred in that year must not exceed the forecast revenue for that year from all customer attachments made in the same year including a margin of safety. The investment portfolio analysis enables the applicant and OEB to track whether the planned system expansion will result in undue short term rate impacts. EBO-188 requires that the utility's <u>investment portfolio</u> for any particular year should be designed to achieve a profitability index of at least 1.1 (our emphasis).

Thus, EBO-188 ensures that over the forty year life of the projects, the utilities' distribution expansion projects pay for themselves, do not require a subsidy from existing ratepayers, and do not cause undue short term rate impacts.

The mechanics of the calculations are contained in Guidelines for Assessing and Reporting on Natural Gas System Expansion in Ontario, Appendix to EBO-188.

EBO-188 has been successful for many years in providing a structure and discipline for the utilities' distribution expansion projects and has been accepted, and well understood, by all parties and the Board. It has stood the test of time.

As stated in the EBO-188 Guidelines under the heading "Overview – Purpose and Objective of the Guidelines", states:

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

The guidelines apply to natural gas distribution expansion projects only, as transmission pipelines must fulfill the requirements of EBO-134, as refined in EB-2012-0092.

The expansion projects that are being proposed by Union and EGD to provide service to new connections are distribution expansion projects, not transmission projects [see EB-2012-0092, Page 1; Transcript Volume 6, Page 232].

EB-2012-0092 Filing Guidelines on the Economic Tests for Transmission Pipeline Applications established revised transmission guidelines, pipeline expansion, which are refinements to the EBO-134 Report.

The EB-2012-0092 Guidelines state, at page 1:

> "These requirements apply to all Ontario Energy Board regulated gas utilities requesting approval to construct new transmission facilities. For the purpose of these Guidelines transmission pipelines are defined <u>as any planned or proposed pipeline project that would provide transportation services to move natural gas on behalf of other shippers within</u>

> Ontario. Distribution system expansion pipelines that are subject to the filing guidelines set in the EBO 188 would not be subject to the proposed filing requirement" (our emphasis).

The EB-2012-0092 Guidelines are clear that EBO-134 applies to transmission line expansions only. EBO-134 does not apply to distribution system expansion pipelines and because of that, has no relevance to this proceeding.

Finally, the provision of section 90 of the Act provides criteria that determines whether the utility must obtain an LTC for the construction of a gas pipeline. An LTC is required if the line is more than 20 km in length, is projected to cost more than $2 million, or incorporates any part that uses pipe with a nominal pipe diameter of twelve inches or more, and has an operating pressure of 2,000 kp, or meets the criteria prescribed in regulations. The provision applies to both gas transmission pipelines and distribution pipelines.

In BOMA's view, the distinction EGD makes in J4.2 between transmission mains and distribution mains may be a "term of trade" that EGD uses internally, but it has no regulatory significance. The words "transmission mains" and "distribution mains" do not appear in the Act or in Board rules. In this case, we are talking about distribution pipelines.

Utilities' Proposals to By-Pass EBO-188

Union has requested an exemption from EBO-188 which would allow individual Community Expansion Projects to proceed at a P/I as low as 0.4 and to exclude the Community Expansion Projects from EBO-188's Investment Portfolio and Rolling Project Portfolio. A project with a P/I of 0.4 means that over its life, that project recovers forty percent of its costs [Transcript Volume 1, Page 20]. Union has requested that the expansion projects not be included in the calculation of the rolling project portfolio, or the investment portfolio, because to do so would cause the rolling project portfolio P/I and investment portfolio P/I to fall below 1.0 and 1.1, respectively. Importantly, the P/I of 0.4 is included after the CIACs (surcharges in the utilities' parlance) from new customers and the host municipalities. The "natural P/I" of many of projects is even lower. Union appears to have chosen a threshold P/I of 0.4 since with that very low bar, it can justify a relatively large capital investment of about $120 million. In EB-2015-0179, Union stated:

> "The main reason for the increase in customers that could be served as the PI decreases from 0.5 to 0.4 [Union had originally proposed a threshold of 0.6] is the impact of a large project that becomes feasible at 0.4" (Exhibit A, Tab 1, UPDATED Page 26 of 47).

EGD proposes a portfolio of rural and remote expansion projects, separate from the EBO-188 portfolio, with a rolling project portfolio of 0.5, with no lower limit on individual project P/Is. EGD stated that they required no lower limit on individual P/Is because very few of the communities they had under consideration would have met Union's project's proposal of 0.4 or greater [Transcript Volume 1, Pages 9-10].

In fact, Union's and EGD's proposed rural and remote project portfolios of twenty-nine and forty projects, respectively, have P/Is that, for the most part, even with their proposed CIACs from new customers, are nowhere close to 0.8.

The two utilities propose their community expansion projects be exempt from EBO-188's rolling project portfolio test, and to reduce the individual project threshold P/Is (Union from 0.8 to 0.4; EGD from 0.8 to 0), which would open the door to projects which are nowhere near economic under EBO-188. These projects would require that the projects be heavily subsidized by the utility's existing ratepayers, even after contributions from the new customers and the municipalities in which they reside [Transcript Volume 1, Page 20]. For example, in the case of a project with a P/I of 0.4, the remaining sixty percent of the cost is assumed by existing ratepayers. That project only generates revenues equivalent to forty percent of the costs incurred to build it over its forty year life.

None of the expansion projects proposed by either utility meets the 0.8 minimum project threshold, let alone the profitability index of 1.0 required to make the expansion project economic. Exempting their portfolios of rural and remote expansion projects from the EBO-188 tests compounds the damage as it allows a very large investment in uneconomic projects to proceed, establishes a "utility within a utility" of uneconomic projects, yet allows the utility owner <u>to earn a full return on projects subsidized by their existing ratepayers</u> (our emphasis), an amount, which in EGD's case, is estimated at $80 million [J5.5].

BOMA is of the view that neither Union nor EGD has made a case that they should receive an exemption from EBO-188. EGD's proposal is even more egregious than Union's; it proposes that there be no lower limit on a project P/I at all. In fact, none of EGD's thirty-nine proposed projects would meet Union's 0.4 project P/I without CIAC. With EGD's version of the CIAC, thirteen of the thirty-nine projects meet the 0.4 threshold. EGD's projects are on the whole even less economic than those Union has proposed. As noted above, EGD also proposes to create a second portfolio, separate from its EBO-188 mandated rolling project portfolio, for its proposed rural, remote and First Nations' projects, with a rolling project portfolio P/I threshold of 0.5, so the entire group of EGD's remote and rural expansion projects would be heavily subsidized by existing ratepayers [Exhibit S3.EGDI.BOMA.25; Transcript Volume 1, Pages 9-10]. The existing ratepayers would pay approximately half the cost of the incremental revenue requirement of EGD's projects (EGD Evidence, Page 30, Table 9). The Net Present Value of the proposed EGD expansion project portfolio is a <u>negative</u> $122.7 million [EGD Evidence, Page 33,

Table 10] (our emphasis). That $122.7 million is paid for by existing ratepayers [Transcript Volume 1, Pages 34-35]. The existing ratepayers lose $122.7 million as a result of EGD's expansion proposal. [The $122.7 million loss is corrected to $156.68 million in J4.1].

Both Union and EGD propose that the EBO-188 simply be ignored in determining whether natural gas service should be extended to large swathes of rural and northern Ontario. In effect, its ambit would be confined to expansion on the periphery of urban areas.

In BOMA's view, no rationale has been advanced for a proposal which would result in so many uneconomic projects being pursued. The utilities' proposals ask the Board to go well beyond demonstrating "flexibility". They want to do away with EBO-188 altogether. For this reason, and the reasons which follow, the Board should reject them.

<u>Precedent Effect</u>

The utilities' proposals include material investments. Union proposes over $120 million capex for its first tranche of twenty-nine projects, and EGD proposes $420 million for its first tranche of forty projects, a total of well over one-half billion dollars. Moreover, once the EBO-188 framework is effectively set aside, and given the utilities' economic incentive and propensity to grow their rate base, it will be difficult for parties and the Board to resist further requests for even more uneconomic projects. Where will the line be drawn? It is not an answer to say, as EGD said, leave it to the Board to draw the line on acceptability on a case by case basis in Leave to Construct ("LTC") proceedings. Without a clear framework to rely on, the Board would have difficulty turning projects down, particularly in light of representations from the government of the day.

For example, only one or two of Union's proposed first tranche of twenty-nine projects are in Northern Ontario, where distances are greater and the terrain more difficult.

Communities in the north, including remote areas and First Nations, have said in this proceeding, and will continue to say, why not us too. NOACC has stated that gas should be available to all remote and rural communities in Ontario, including Northern Ontario [Transcript Volume 4, Page 21]. The Canadian Gas Association has just published a study, which deals with the use of LNG to serve remote communities and remote industrial projects. Will existing customers be required to pay for these types of very costly initiatives?

Benefits and Costs

BOMA finds the economic analysis of Dr. Nieberding persuasive. He states that, to establish that an economic basis might exist for subsidizing natural gas expansion in Ontario, four conditions would have to be met:

- first, natural gas expansion produces social benefits to Ontario and not just private benefits for the areas in which the expansion occurs;
- second, the social benefits associated with switching to natural gas exceed the private benefits of doing so;
- third, the social benefits are linked to the natural gas expansion; and
- fourth, the magnitude of the benefits exceeds the amount of subsidy provided [Transcript Volume 5, Pages 5-6].

The evidence filed in this case makes it clear that the economic benefits from the expansion are private benefits in that they are, for all practical purposes, enjoyed only by the customers who convert to natural gas and their host communities which constitute a very small part (about one percent) of Ontario energy consumers (16,000 for EGD and 9,000 for Union). For example, under EGD's proposal, the existing ratepayers lose, on a present value basis, $156.68 million [Table 10, Page 33 of EGD's evidence, as corrected at J4.1]. For example, EGD estimates that the energy cost savings of the 16,000 customers that switch to gas are $384 million [Transcript Volume 1, Pages 34-35]. The net benefits (total fuel savings less conversion costs borne by the customers) is $357 million. These are very large sums. Dividing that $357 million by 16,000 new customers, the benefit to each new customer is about $22,000.00 for the conversion [Ibid]. Moreover, under the utilities' proposals, the benefits accruing to newly connected customers are offset by the aggregate losses of existing ratepayers due to higher rates. Over the expansion project's forty year lifecycle, the existing customers will pay $439 million in rates to subsidize the projects (more than the initial capital cost of $410 million of the project [Transcript Volume 1, Page 43]. The existing ratepayers will pay at least half the cost of the expansion [Table 10, EGD evidence]. The gain to local equipment suppliers, and service companies, will be offset by losses to those same or other local companies as their propane, fuel oil, electricity, and business is reduced.

On the other hand, the economic benefits to utility's existing ratepayers are very very small. Union estimates that the annual per customer benefit for the 1,387,000 general service customers from spreading its OM&A fixed costs over a marginally larger number of customers to be approximately 0.45 cents per year [J4.6; S15.Union.BOMA.59]. This benefit must be set against their loss of $156.6 million. The utilities suggest that the revenues from attachments of new customers beyond the ten year period used to calculate the P/I index, will result in lower rates for all customers, including existing customers. However, the evidence suggests that the bulk of the attachments are made in the first ten years [Transcript Volume 4, Page 52]. The percentage of attachments made after ten years (from conversions or new growth) is generally much smaller and will not result in much incremental revenue. That is why EBO-188 only allows forecast attachments for ten years after installation in its feasibility analysis. In addition, what revenue there is will have less economic value. Under the Board's approved Net Present Value analysis in EBO-188, the attachments made in later years are worth less because the revenues have to be discounted over a longer period. So the benefit to existing ratepayers would be very small.

The utilities have not yet identified large industrial consumers to be "anchor customers" for the expansion and provide substantial CIACs, consistent with the benefits the expansions would provide them. In fact, the overall shape of the community programs has not been well-defined, with the partial exception of Union's first four projects submitted in EB-2015-0179. In contrast, Union's Red Lake expansion project is an example of a creative approach to mains expansion. EGD has identified only two or three industrial/commercial projects in one municipality. Each of Goldcorp, the Government of Ontario, the Federal Government, and the Municipality of Red Lake paid CIACs to the project, which then required no subsidy from existing customers and virtually no expansion to the Union rate base. The overall framework was developed by Goldcorp in concert with Union.

Given the localized nature of the proposal expansions, the social and job creation benefits for the province as a whole would be minimal to zero.

While BOMA is of the view that the only relevant economic evidence is that pertaining to EBO-188, the utilities have provided no evidence of any broad social, environmental and economic benefits to the province as a whole. With respect to an ICF study performed for the Canadian

Gas Association, which Union filed in EB-2015-0179 [Exhibit B.CCC.5.Attachment 1] on the environmental impacts of natural gas production in Canada, Union noted that since the study was national in scope, and was not broken down by province, it was unable to pull Ontario specific numbers from the report [S15.Union.BOMA.51].

To summarize, the utilities' proposals do not meet the economic test for a subsidy laid out by Dr. Nieberding and cited above, nor do they accord with the general ratemaking principle that benefits should follow costs.

Allocation of Risks

BOMA is of the view that the risk allocation being proposed by the utilities in this case is inappropriate for a project in which the utility shareholder earns substantial profits from the project while the utility's existing ratepayers underwrite much of the project costs. The utilities both flatly refuse to accept a lower rate of return for the forecast uneconomic expansion projects. The utilities take this view, notwithstanding the fact that they, together with Ontario Federation of Agriculture, vigorously lobbied the provincial government to create a rural or remote program throughout 2014 [Transcript Volume 4, Pages 45-46].

Moreover, the utilities take the position that if the actual attachments over the ten year period are less than forecast, then the subsidy from the existing ratepayers should increase. They claim that their risk is no different than it would be in an expansion and a normal rate case.

However, under a cost of service approach, it is the utility, not the ratepayer that bears the revenue risk if fewer than forecast attachments materialize during the test year. So the utility is shifting the risk to its ratepayers.

Second, the utilities are asking for Y-factor treatment of the proposed capex during the remaining term of their respective IRM programs and even afterward. This is a lower level of risk than they would have without Y-factor treatment. Y-factor protects them against cost overrun risk unless they are imprudent.

Finally, by seeking to by-pass EBO-188, the utility also shifts to ratepayers the risk by removing the margin of safety built into required investment portfolio of 1.1. In EBO-188, at 2.3.10, the Board states:

> "The Board concludes that the Investment Portfolio should be designed to achieve a positive NPV including a safety margin (for example, corresponding to a P.I. of 1.10). The Board believes that a portfolio designed in this way will minimize the forecast risks and hence more likely achieve the desired results of no undue rate impacts".

The ratepayers lose the protection against undue or unforeseen rate impacts under the utilities' proposal.

<u>Nature of Gas Service</u>

Fourth, these projects are not essential services in the sense that electricity is. Many rural and remote communities have survived and prospered over the years heating with fuel oil, propane, coal, electricity, or wood. Providing yet another fossil fuel home heating and water heating method, especially given the government's GHG policy, does not have the same compelling rationale as providing rural electricity service or even telecom service, without which a community cannot exist, develop and thrive. As Mr. Todd has noted, Ontario does not have universal service itself as a goal in natural gas [Transcript Volume 3, Pages 225-227]. While existing customers would likely see lower heating bills, there are still better or equally good bill-reducing alternatives available for many residences than gas with lower environmental and GHG impacts, for example, heat pumps. Finally, utility owners are expecting ratepayers to pay for the entire cost of GHG allowances. They want to pass through the costs in rates. They are not volunteering to share the burden by absorbing a portion of the allowances, as participants in a competitive market, merely the propane and fuel oil markets would likely have to do.

Fifth, the Ontario government is not asking the Board to facilitate uneconomic expansions. To the contrary, the Minister of Energy, in a letter to the Board Chair dated February 17, 2015, simply requested that the Board continue to "examine opportunities to facilitate access to natural gas to more communities..." and stated that he "appreciates your (the Board's) continued support to ensure the rational expansion of the natural gas transmission and distribution system for all Ontarians" (our emphasis).

BOMA believes the use of the word "rational" in the sentence above (this word is also used in section 2.3 of the Ontario Energy Board Act (the "Act")) should be read to mean "economic". In other words, the Minister is not encouraging the Board to approve uneconomic projects which cannot, even over the long term, be self-supporting. The Minister is not asking the Board to direct existing utility ratepayers to subsidize uneconomic expansion projects.

The Board should not "leap into the breach" and change well-established regulatory principles to do something the government hasn't requested it to do.

The Board, for its part, invited utilities to make proposals for a framework, which allows for the connection of additional rural customers, provided some examples of "regulatory tweaks" that the Board might make to the existing rules, including early recovery of capex during an IRM period, and noted it would welcome proposals, which "incorporate flexibility" with respect to cost recovery (eg. ROE, depreciation period, recovery of capital contributions, etc.). While the utilities responded to the "possibility of increased flexibility" with alacrity, they completely ignored the latter part of the Board's advice. They flatly refused to even consider lowering the ROE, in respect of the rural and remote expansion project assets, or extend the depreciation period permitted for those projects [Exhibit S3.EGD.BOMA.90].

Sixth, if the government wishes to have uneconomic natural gas expansion projects proceed, it should subsidize them through the government's recently announced programs to encourage the expansion of natural gas into rural and remote communities. In fact, the government has announced on several occasions in the last two years a loan and grant program (for example, in the 2013 LTEP (need for action), the 2015 budget, the 2016 budget (the policies)), but has apparently not yet finalized the program terms and conditions, nor released any economic rationale for the program. The lead Ministry for the program is the Ministry of Industrial Development and Trade, which suggests an industrial/rural development focus for the initiative. The government has the personnel, the tools, and the capital to integrate the expansion into a comprehensive rural development program, which could apply in cases of "rural", "remote" and First Nations communities. Perhaps more important, the government can tailor the program to fit into the broader contours of its Climate Change Action Plan, released on June 10, 2016 (see below).

Given that the government has decided to intervene in the market, it should consider a revolving loan fund to finance and subsidize the initiatives by customers in the rural and remote communities to reduce their energy bills, including cost of energy efficiency improvements, such as heat pumps, and where appropriate, conversion to natural gas. Revolving loan funds are a common way for governments at all levels in Canada, including regions, cities, and provinces, including Ontario, to promote desirable activities, especially in the housing and energy sectors.

Moreover, the revolving fund could utilize the Green Bank, proposed in the GHG Action Plan, and the accompanying grant component of the government's grant/loan program could be supplemented by a part of the significant funds proposed in the Action Plan for the retrofit of existing buildings. Moreover, Ontario could likely establish such revolving fund by regulation.

Because a revolving loan fund is normally a fixed capital fund, the loan, which could be combined with a grant, would be repayable to the fund or at least the principal of the loan would be. The loan could be at a level less than the current commercial rate.

Importantly, a repayable loan from the provincial fund would not trigger HST on the repayment of capital unlike the proposed rate increase for existing customers, and the TES payments from new customers, whether treated as revenue or a CIAC by the utilities [S3.EGDI.BOMA.1]. The repayable loan method avoids residential customers having to pay a thirteen percent HST.

If the government truly believes that these projects will provide benefits for all Ontarians, then based on principles of public finance and regulatory economics, they should, as Dr. Nieberding pointed out, ask all Ontario taxpayers to subsidize them [Transcript Volume 5, Page 6]. For their part, the utilities have stated that they have done little, if any, analysis of the industrial development (job creation) potential of these uneconomic projects [S3.EGDI.BOMA.45]. To the extent that additional local jobs are created to build out and maintain the gas network, they are likely to offset by loss of jobs now in fuel and propane businesses. They have simply assembled groups of communities based on financial criteria. EGD demonstrated uncertainty about location of some of the municipalities in their portfolios. For example, EGD suggested that Eganville was southeast of Ottawa, which would come as a surprise to anyone who grew up in the Ottawa Valley.

Seventh, there is no clear definition of "community" in the evidence for this proceeding (Issue 1) beyond the idea that it is a group of at least fifty customers. The definition proposed by Union and EGD is a group of at least fifty dwellings (customers), but the issue of geographic span of the group of dwellings has not been not considered. Must they all be within one square mile, half square mile? If not, what about fifty farms set along a five mile stretch of secondary road? Are they a community? Must the dwellings be within a circle with a diameter of one mile, two miles, five miles? How does the Board justify the different treatment of two dwellings; one in a "community", and one not, or for that matter, between a member of a qualified rural community, which needs, in the Union franchise, to make a CIAC payment (surcharge), calculated in an amount that allows its payback on its conversion investment plus the CIAC payments not to exceed four years, versus a customer in an already serviced area who lives several hundred feet off of a main and needs to make an even larger CIAC. How is a rural or remote project to be distinguished from other off-main projects, such as to a "new town" or new large subdivision, built in the outskirts of an existing city or town? In other words, how are these CIACs for these rural or remote expansions differentiated from "normal" expansions? There is also no definition of rural or remote in the proposal. Are all remote communities eligible? Is the federal government prepared to contribute part of the cost of bringing gas service to remote or rural First Nations communities which are currently heating with diesel or fuel oil, currently paid for by the federal government?

<u>4(f)</u>

BOMA is of the view that economic, environmental, and public interest components in not expanding natural gas to a specific community should be considered in the framework from the perspective of examining whether there are alternatives to expanding gas to the proposed communities or potential complementary measures that should accompany any such expansion.

Furthermore, prior to granting LTC to a project under section 92 of the Act, the Board must consider these alternatives and complementary measures in determining the public interest.

For example, BOMA supports the idea that prior to expanding gas service to a new community, the Board should require that potential interested customers have taken advantage of existing utility/government gas conservation programs. It is generally accepted that many conservation measures are more economic than utility new build options. The economic attractiveness of energy efficiency measures has been recognized by the Ontario government in its Conservation First program. Moreover, the Board has directed gas utilities on more than one occasion to ensure that any infrastructure expansion proposals be evaluated against DSM alternatives, and that the gas utilities adopt an integrated resource planning approach. EGD has stated that it would not object to the principle of looking at alternatives to natural gas expansion [DSM Guidelines for Natural Gas Utilities (the "Guidelines")]. EGD also agreed that it would not pursue initiatives that were not in the interests of the people that were served by them [Transcript Volume 3, Page 10]. In BOMA's view, potential gas customers should be required to implement Conservation First audit and analysis programs, and to implement energy efficiency measures prior to, or at the same time as, the conversion to gas. If this does not happen, volume forecasts will be higher than warranted. More important, the customer's bill savings from conservation programs may be larger than the savings from simply converting to gas. Or it may be that with a comprehensive conservation program, the conversion to gas is no longer economic or is no longer the least cost measure. The conservation programs are available to all consumers, regardless of what fuel they use for space and hot water heating. EGD's concern about there being insufficient funds should be assuaged, given the government's program announcement, including its GHG reduction plan.

The heat pump option should also be assessed as one of the DSM alternatives prior to conversion. Heat pumps are both an energy conservation measure, and a GHG reduction measure. Both the Minister's Conservation directive to the OEB and the Guidelines for gas DSM included heat pumps as a conservation measure, so that it would receive more exposure and prominence and financial support in the gas and electric utilities efficiency programs under the Conservation First umbrella.

EGD has stated that it would not object to the principle of looking at alternatives to natural gas pipeline expansion proposals, which is consistent with the Board's recent comments.

The environmental/GHG policy context of the proposed conversions including the energy efficiency components of the GHG Action Plan are discussed in more detail under issues 10 and 11 below.

Issue 5

Utilities should be able to collect CIAC from to-be-served customers to offset the cost of the expansion, and allow a project to meet the EBO-188 0.8 threshold. However, while the utilities characterize these payments by new customers to the utility as surcharges, and wish to include them in general revenues, they are in fact CIACs paid over a period of months instead of in single upfront payments to make them more affordable for residential and small business, and to, in the case of Union's proposal, allow the connecting customer to have a payback of four years or less, on its conversion costs, including the TES. They should be characterized as CAICs for ratemaking purposes. The customer payments, whether made on a lump sum, annual, semi-annual, quarterly, or monthly (as proposed) basis are clearly payments made to offset the capital cost of the expansion and should be an offset to the utilities' rate base and deducted from the rate base as and when made. In the Red Lake expansion, Goldcorp's CAICs were paid in several installments, but were treated as CIAC [S15.Union.BOMA.66]. BOMA believes that what the evidence supports the treatment of the SE5 treatment as aids to construct to ratepayers [J6.1]. It endorses Mr. Aikens' analysis and conclusion on this issue. It is also the traditional treatment of such payments. Utilities have not justified their proposed changes. BOMA would support the Board increasing the payments from new customers if the evidence shows that the benefits obtained by the new customers (the savings in energy bills) exceed the costs they have incurred (conversion costs plus the present contribution levels), taking into account the costs and benefits that will accrue to the "converting consumers" under our proposals.

Issue 7

The Board should not grant Y-factor treatment to the utilities' proposed capex for their expansion proposals.

Union's and EGD's current IRM programs expire on December 31, 2018, in two and one-half years' time. Union's evidence is that, assuming a Board decision in the case in September 2016, it would spend approximately $9 million in capital costs over the period to the end of the IRM [Transcript Volume 6, Page 234]. These are not material expenditures for a company of Union's size and should not require Y-factor treatment. In fact, they would not meet the EB-2012-0459 materiality criteria. Union can deal with the post-2015 expenditures in its rate base at rebasing in 2019. The same argument is true for EGD, as its projects in 2017 and 2018 would total about

$100 million [S3.EGDI.BOMA.34]. Moreover, unlike Union, EGD does not intend to defer the revenue in deferral account and eventually refund it to ratepayers. The companies have not filed evidence which demonstrates the financial need for Y-factor treatment. Union argues that in assessing whether a Y-factor is warranted, the entire multi-year (five years or more) string of projects should be considered as a "project" separate for the rest of Union's expansion projects and capital expenditures, and hence eligible for Y-factor treatment as a distinct program [Transcript Volume 6, Page 234]. BOMA does not agree with the concept of a separate identifiable remote and rural project portfolios, with their own rolling portfolio profitability index for the reasons outlined above, but as noted earlier, if the collection of discrete community expansion projects is to be treated as a separate "utility within a utility", it should be special in other ways as well. The utility should accept a reduced return on equity, and assume forecast customer capture risks and cost overrun risks.

Issues 8 and 9

Issues 8 and 9 deal with the issue of access of new entrants to provide service to communities that do not have service to natural gas.

Issue 8 states:

> "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?".

Issue 9 states:

> "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)".

In addition, the Board, in Procedural Order No. 3, added the following comments in respect of Issue No. 8:

> "In relation to issue # 8, the OEB would be further assisted if the parties could consider the following additional questions: Should the Municipal Franchise Agreement approval process be accompanied by a selection process? Who should conduct the process and what should the selection criteria be? How would the needs of large users be considered? Submissions on the current purpose and use of the Municipal Franchise Agreement would also be of assistance."

BOMA is of the view that having qualified new entrants willing to serve currently unserved areas without subsidies is in the public interest. They provide competition for unserved markets which should lead, all else being equal, to lower costs of service and lower rates.

Consistent with its view that Union and EGD ratepayers should not subsidize uneconomic expansion projects, BOMA is of the view that the Board should not subsidize new entrants' costs to construct facilities to serve unserved areas of Ontario. However, the Board should not impose institutional barriers to new entrants, and should work to remove any existing barriers, as discussed below. For example, existing utilities should not be permitted to refuse to deliver or sell gas to new entrants, or to charge them more than other wholesale customers are charged.

The Board should require that potential new entrants demonstrate technical and business competence in the utility business, and that they have the financial resources to properly capitalize and grow the proposed business. However, in any franchise, certificate, or LTC application, potential new entrants should not be held to a higher standard than utilities already operating in Ontario. In other words, a new entrant need not demonstrate that it can offer something that Union or EGD cannot. For the Board to act otherwise would be to impose a barrier to competition for markets.

The Board has held that gas franchises are not exclusive in Ontario, and has awarded franchises for different parts of the same municipality to different distributors. In addition, Union and EGD have acquired franchises and certificates for some municipalities which they do not yet serve. In some cases, they have held these franchises and certificates for many years [S3.EGDI.BOMA.24]. While franchises are not exclusive in the sense that the Board can and has approved franchises for parts of a municipality, it would not typically offer a franchise to two utilities for the same geographic area of a municipality. However, the certificate of convenience and necessity does convey an exclusive right to construct works in an area, subject to the utility obtaining an LTC. For example, in EBLO 252, EBLO 254, a case in which both Union and EGD applied for a franchise, certificate and LTC facilities to serve several municipalities, the Board encouraged the utilities to negotiate a resolution of the matter, which they did. Each of them agreed to serve a part of the contested municipalities.

BOMA recommends that the Board should introduce a "use it or lose it" condition into franchise approvals and issuances of certificates, in the form of a condition that the successful applicant apply for an LTC within three years of the approval and issuance. That change would remove one current barrier to entry.

BOMA further recommends that the Board should, pursuant to its authority to approve franchises under the Municipal Franchises Act, prescribe a process which municipalities must follow in cases where more than one utility wishes to serve a currently unserved area, and guidelines as to what factors the Board will take into account in approving franchises and certificates.

The process should be conducted by the Board, not the municipality. Having the Board conduct the process makes sense, given that the Board would need to approve the result in any event, would ensure that the same criteria would be applied in all cases. Moreover, the municipalities do not have the required expertise. The Board has.

For example, the Board would ensure that inappropriate inducements were not being offered to the municipality by any applicant. BOMA is of the view that cash payments by an applicant to a municipality, presumably payments which would form part of the utility's cost of service and paid for by ratepayers, should not be acceptable criteria. BOMA's view would be the same if the cash payment were paid by the utility's owners.

The guidelines would focus on whether the applicant has the technical, business, and financial resources and experience to properly serve the municipality in question. The Board could receive evidence or submissions from the municipality(ies) which the applicant wishes to serve. In addition, the Board would require the applicant to include a pro forma forecast of utility financial statements, including forecast attachments, volumes, capital and OM&A expenses, revenue requirement, approximate rates, and whether it would require CIACs from the new customers, and the amount of the subsidy, if any, from the Ontario government's recently announced grant and loan program. As noted above, BOMA suggests that in assessing any application for franchise approval, certificate of convenience and necessity, or LTC, the Board require the applicant to advise what amount of government subsidy grant and/or loan, if any, it would require to proceed. BOMA notes that in its franchise agreements with Kincardine, Arran-Elderslie and Huron-Kinloss, which it has filed with the Board in EB-2016-0137, EB-2016-0138 and EB-2016-0139, respectively, EPCOR has committed to file an LTC for its proposed facilities in the three municipalities within stated periods after receiving final decisions, including appeals, in this case, and the decision of the Government of Ontario, with respect to EPCOR obtaining funding from the grant or loan program. It has not stated whether it would continue with its application in the event it did not receive a government subsidy, but it has negotiated the contractual right to do so. BOMA would expect any applicant, including Union and EGD, in the event the Board does not permit them to burden their existing ratepayers with subsidizing their expansion costs, to condition any LTC applications they made on receipt of a government subsidy. The Board could also, as part of its decision, determine the allocation of risk between the applicant's shareholder and the ratepayers for the expansion.

The Board would also be able to ensure that utilities currently serving areas adjacent to the unserved area did not put in place any barriers to disadvantage potential new entrants.

BOMA agrees that an alternative process could have municipalities conducting the selection process with subsequent Board approval. However, that process would be more cumbersome, and given the need under the Municipal Franchises Act for Board approval of such decisions, would mean two processes rather than one. It would also likely be more costly, due to duplication and each municipality's need to hire outside advisors to advise on the selection process, prepare RFIs, RFPs and the like. There is also merit in having uniform criteria used to choose applicants across the province. This could be achieved by insisting that the OEB guidelines be used by all municipalities in making their decisions.

However, BOMA suggests the Board conduct the selection process. While BOMA does not believe the Board should try to impose a uniform distribution rate (it does not now), it is important that a proponent make clear in its submission what its approximate cost of service (rates) will be.

Changes to Franchise Agreements and Certificates

The Board-approved model Franchise Agreement should remain, as it deals mainly with the details of the relationship between the utility and the municipality, once the franchise has been granted and approved by the Board, in particular, the details of the terms and conditions under which the utility has access to municipal roads and other facilities and the cost sharing of any relocation costs due to future municipal works. The certificate of public convenience and necessity, which is currently applied for and granted as part of the franchise agreement approval process, appears to have little independent value today. In most cases, the applicant utility must still apply to the Board for an LTC, and even when it is not required to so apply (for small pipeline expansion), it may do so, and often does, to obtain access to the Board's expropriation process. BOMA believes that the certificate requirement could be eliminated.

BOMA also suggests that the Board should consider the desirability of requiring gas distributors to be licensed. Existing gas service providers would be grandfathered for some reasonable period of time. The licence criteria and application process would resemble that used in the electricity industry. The utility would need to be licensed prior to applying for an LTC. The Ontario Energy Board Act would need to be amended to accommodate this change. Like in electricity, the license would not be exclusive but in practice, more likely a monopoly in a given geographic area. The Board would continue to approve the uniform franchise agreement and any proposed variation from that document. Since it is important that the basis on which utilities and municipalities collaborate and share costs should be uniform across the province, absent any compelling local circumstance, the franchise agreement would be an Appendix to the licence, which would be the key document.

Issue 12

To reiterate earlier comments, BOMA believes that any subsidy for utility rural and remote expansion proposals, above or beyond the traditional CIAC, from the to-be-connected customers and the host municipality, should come from the Ontario government, not from existing utility customers. This approach would be best from both public finance and regulatory economics perspectives. The government announced its $230 million grant and loan program initially in its 2015 budget and several times since. The Ministry must be close to having the criteria ready, and the program ready to launch. BOMA assumes Board staff would have input into the program design.

The government funds should be used to plug the gap, if any, between the rural expansion project's forecast costs less the agreed CIAC and contribution from the municipality(ies).

BOMA believes that the government should disburse the amount of its subsidy to the successful proponent, once it has been granted LTC.

Issues 10 and 11

Issues 10 and 11 deal with the impact of the Ontario government's proposed cap and trade program and related GHG reduction incentives on the to-be-connected customers' savings from switching from their current fuels to natural gas (Issue 11) and how the cap and trade program will impact on the framework for the expansion of gas service to rural and remote communities that the Board may establish in this case (Issue 10).

With respect to Issue 10, there has been considerable recent information from the Ontario government, including statements from the Premier and various Ministers, the leaked fifty-seven page "cabinet document", which outlined Mr. Murray's proposal to cabinet, and, most recently, Ontario's Five Year Climate Change Action Plan, 2016-2020 ("Action Plan"), released on June 10, 2016, on the manner in which natural gas will be treated within the government's climate change policy. The Action Plan makes several references to natural gas.

First, the Action Plan states, by way of context, that:

> "Currently, natural gas combustion and carbon-based electricity emissions from buildings represent 24 per cent of Ontario's climate change-causing air pollution. Because of Ontario's growing population and economy, greenhouse gas pollution from its buildings sector continues to rise each year – with no end in sight. Without action in this sector, we will lose the fight to reduce carbon emissions across the economy" (page 16) (our emphasis).

The Action Plan further states at page 25, in discussing the role of natural gas in buildings and homes that:

> "Ontario will build upon progress made. The province will continue to reduce greenhouse gas pollution in existing housing and other buildings, and ensure new buildings do not contribute to increased net greenhouse gas pollution. For existing homes, technologies such as geothermal and other home heating solutions in new, highly efficient buildings can also be complemented with natural gas" (our emphasis).

The Action Plan also emphasizes the role to be played by heat pumps. It speaks of significantly increasing the use of heat pumps (page 16). It notes at page 27 (4.1) that the government will "help homeowners purchase low carbon energy technologies such as geothermal heat pumps and air-source heat pumps".

Finally, the Action Plan (pages 28 and 68) requires the introduction of a renewable natural gas component for natural gas consumed in Ontario and allocates $60,000,000.00 to $100,000,000.00 to achieve/encourage the use of cleaner, renewable natural gas in the industrial, transportation, and building sectors, commencing in 2017. The Action Plan states that the goal of the initiative is to ensure the lowest possible carbon content (of natural gas) to reduce building and transportation emissions.

While the government has denied any plan to ban natural gas, it is not yet clear what restrictions would be imposed over time on the use of natural gas for space and water heating, and what new opportunities may arise, such as more emphasis on cogeneration, district heating, and gas fired distributed generation generally. The government does foresee an expanded role for natural gas in the truck transportation sector. What is clear is that demand side alternatives, energy efficiency measures, including the replacement of older gas fired boilers with newer, more efficient ones, already a well-established conservation measure, ground and air source heat pumps, which have been characterized by the Ontario government to be energy efficiency measures, have increased in importance due to the GHG Action Plan, and should be emphasized in any Board framework for natural gas expansion. The government's GHG Action Plan reinforces the government's Conservation First plan. As discussed above, BOMA suggests that the Board require any rural or remote customer proposing to switch to natural gas be required to implement any economic energy efficiency measures first, including heat pumps. As noted above, the government has stated it will provide incentives for heat pumps and other conservation measures (pages 26-27). The availability of multiple funding sources through the GHG Action Plan, notably the Green Bank, are the Low Carbon Home Program (and counterparts for schools, hospitals, and apartments), together with the announced rural, remote incentive loan/grant program, should alleviate EGD's concerns about available funds [Transcript Volume 4, Page 66]. The utilities should provide the required analysis through their DSM programs, the size of which should be increased accordingly. Alternatively, the government should fund these required studies with a portion of the funds it has set aside for the gas conversion program. The retrofit costs could be financed in part through the utilities' DSM programs, augmented as required, or through a portion of the government funds that the Action Plan has set aside for comprehensive retrofit measures [Action Plan, Page 67]. As noted earlier, a revolving loan fund would be a good method to implement such measures. The overall effort should be coordinated by the gas utilities, with collaboration with the electric utilities in the proposed expansion communities, and the Ontario government, and other stakeholders. Evidence in this case suggests that natural gas space heating emits about ten times as much carbon into the atmosphere as geothermal [Transcript Volume 5, Page 70], and geothermal would be less costly [Transcript Volume 5, Pages 51-52]. Mr. Todd has agreed that geothermal coupled with district energy could be evaluated as a community based alternative to natural gas expansion [Transcript Volume 3, Page 225]. There is a recognition that these were realistic alternatives for rural and remote communities to conversion to natural gas. Heat pumps are eligible retrofits under the Action Plan and should be financed in the same way.

With respect to Issue 11, the Ontario government has now published its Action Plan, and passed its GHG legislation and regulations. It is now generally expected that gas distribution utilities will purchase emission allowances on behalf of their customers and pass those costs through to their customers. The Board is currently conducting a consultation on the method utilities will use to recover these costs. Proceedings will be held later this year to establish rates which establish the details of the cost recovery mechanisms. Given that the fuel oil and propane combustions are more GHG intensive than burning natural gas, their suppliers will likely also need to purchase allowances, so the impacts for customers who switch or do not switch from those fuels to natural gas, should be about the same. For customers that switch from electricity to natural gas, the impact is not as clear. The utilities argue that natural gas is the marginal (peaking fuel) for producing electricity in Ontario, and therefore, switching end use customers from electric space and water heating to natural gas space and water heating reduces GHG emissions. They have not supported those claims with hard IESO data. But if it were the case, more appropriate course of action in the longer term would be to the extent feasible, minimize the use of natural gas as a peaking fuel.

It is clear that the impact of the forecast savings achieved by the customers in the twenty-nine Union and forty EGD expansion projects who switch from higher GHG content fuels to natural gas is a very small percentage of the reduction in GHG required to meet the Action Plan's 2030 targets, in the order of 0.01 percent (Union) [S15.Union.BOMA.74] and 0.05 percent (EGD) [S3.EGDI.BOMA.19].

GHG savings would increase if the utilities revised their proposals to require "switching customers" to install all economic energy efficiency measures prior to switching, and would increase further if heat pumps were installed instead of gas furnaces, where they provide the most economic solutions.

Further Legal Matters

In Procedural Order No. 3, the Board states:

> "The OEB asks that parties further consider what, if any, changes to the OEB's jurisdiction would be helpful in allowing the OEB to foster the rational expansion of natural gas service in Ontario".

KPMG, in a study performed for Board staff (see above), which examined rural and remote gas expansion regimes in place in several jurisdictions, did not find any case where the ratepayers of one utility were required to subsidize uneconomic expansion investments of another utility.

Some parties have suggested sources of funds to subsidize uneconomic expansions by gas utilities generally into unserved areas, other than payments from the ratepayers of another utility. These sources include a reserve fund, funded by a Board-approved levy on all gas sold or delivered in the province. The reserve fund would be administered by the Board. It would be used to subsidize otherwise uneconomic (non-compliant with EBO-188) expansions to rural, remote, and rural and remote First Nations communities. See, for example, the proposal presented by Dr. Yatchew in his evidence on behalf of EPCOR.

Dr. Yatchew explores programs in place in both Alaska and Maine. In Alaska, the new entrant was eligible for subsidies from a program established by legislation. London Economics ("LE"), in its evidence, submitted on behalf of Union, analyzed rural and remote gas, electricity, and telecommunication, expansion programs in Ontario and Alberta (electricity), Nebraska, North Carolina, and New York (natural gas) and United States and Canada (telecom). LE agreed that in each of the jurisdictions examined, except New York, the rural expansion programs were underpinned by legislation authorizing the regulator and/or the government to create and fund such a program and provide the payments [Transcript Volume 2, Pages 89-90]. The details of the structures employed varied but they were all supported by legislation. The New York rules covering expansions to unfranchised areas put the expanding utility at risk, if the expansion proves not to be economic after a five year trial period [Case 89-G-078, Statement of Policy Regarding Rate Treatment to be Afforded to the Expansion of Natural Gas Service Into New Franchise Areas, State of New York Public Service Commission, December 11, 1989].

Ontario, on the other hand, does not have such legislation in place for natural gas. The Ontario Energy Board Act contains relatively little guidance on expansions of natural gas distribution systems and natural gas transmission systems. In BOMA's view, it would need legislation to establish a regime such as the reserve fund.

As the Board and parties are well aware, section 90 of the Act provides that Board approval is required for the construction of a gas pipeline that is:

- more than 20 km in length,
- is projected to cost more than $2 million,
- any part of the line uses pipe with a nominal pipe diameter of twelve inches or more and has an operating pressure of 2,000 kp, or
- meets the criteria prescribed in the regulations.

If, under section 92, the Board decides such a line is in the public interest, it must approve it. So its jurisdiction is very broad. Part of assessing the public interest is assessing the economic viability of the pipeline, for which the Board uses EBO-188 (for distribution lines). Unlike the National Energy Board, the OEB does not have the jurisdiction to order a gas utility to construct a pipeline. It can only require that customers along the line of an existing main be served pursuant to section 42(2).

The Board does not have the explicit authority to collect monies in rates to fund a reserve, such as the one proposed by Dr. Yatchew, and to authorize the allocation, as described above, nor does it obtain that authority from the doctrine of necessary implications. If the Board wished to have that authority, it would require a change in the legislation.

The legislation would need to describe the purpose and function of a levy, provide for existing ratepayer protection, and make it clear that the Board was authorized to administer such a fund, or delegate administration to a third party, while remaining accountable for the results.

BOMA also questions the legality of some aspects of the utilities' proposals in this proceeding.

BOMA believes that modest modification to EBO-188, such as reducing the minimum project P/I from 0.8 to 0.7, while retaining the rolling project portfolio P/I of 1.0, and the investment portfolio of 1.1 is within the jurisdiction of the Board. These modifications are legal because they do not strike at the heart of the EBO-188 which is that uneconomic project, projects that are not forecast to pay for themselves over the projects' lives, should not proceed. And other similar modifications can be envisaged, perhaps a modest lengthening of the attachment period.

However, in BOMA's opinion, the Board does not have the jurisdiction to approve the creation of a new portfolio of uneconomic projects, separate from the EBO-188 portfolio, which run directly contrary to the letter and spirit of EBO-188. These portfolios would have to be subsidized by the utility's existing ratepayers in perpetuity. Portfolios with P/Is of 0.4 and 0.5 never pay for themselves over their lives. These proposals create a "utility within a utility", the purpose of which is to pursue uneconomic expansion projects. These projects are inconsistent with legal basis of just and reasonable rates, which is that utilities' rates be cost-related.

These projects and the portfolios of such projects they constitute are outside the zone of economic reasonableness, as they are nowhere near economic even when supported by the proposed CIACs from the to-be-attached customers.

All of which is respectfully submitted, this 20th day of June, 2016.

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