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April 7, 2016

Reply To: Thomas Brett
Direct Dial: 416.941.8861
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Our File No. 161734

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 IRs

Pursuant to Procedural Order No. 2, please find enclosed BOMA's IRs.

Yours truly,

FOGLER, RUBINOFF LLP



Thomas Brett

TB/dd

Encls.

cc: All Parties *(by email)*

ONTARIO ENERGY BOARD

**GENERIC PROCEEDING ON NATURAL GAS
EXPANSION IN COMMUNITIES THAT ARE NOT
SERVED**

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

April 7, 2016

Tom Brett
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Counsel for BOMA

PART A ENBRIDGE GAS DISTRIBUTION

General

1. **Ref: Page 8/36, Paragraph 29, Rate Rider**

Has Enbridge considered any options for existing customers other than a rate rider, which will attract payment of HST in addition to the rate rider itself, thereby adding an additional 13% to costs associated with the rate rider? If so, please file the results of the analysis. If not, why not? Over the timeframe estimated for the collection of the rate rider from existing customers what will be the total provincial share of the HST revenue?

2. **Ref: Page 12/36, Paragraph 36**

With respect to the ICF study for the Canadian Gas Association, why does Enbridge assume the results for Canada as whole can be assumed to apply to Ontario, given that Ontario's electricity system has been significantly decarbonized already?

3. **Ref: Page 20/36, Paragraph 58**

With respect to the average rate impacts being limited to \$2.00 per month, BOMA Toronto assumes that this amount is the average for a residential or general service customer. What is the estimate of the total rate impact for Enbridge other customer classes, by rate class per month and for the lifetime of the community expansion projects included in Enbridge's submission?

4. *Ref: 12.EGD.1*

- (a) Does EGD agree that in the Ontario 2016 budget, while the \$200 million CEP loan program, introduced in the 2015 budget is reaffirmed, there is no reference to the \$30 million grant program?
- (b) It appears from the 2016 budget that the Province has dropped the grant program. What is EGD's view?
- (c) In EGD's view, why has the province not yet developed criteria for the loan/grant program, given that the program was announced in the 2015 budget, and was referred to in the 2013 LTEP?
- (d) When does EGD anticipate the provincial program will become operational?
- (e) What is EGD's view as to how the loan program will fit into the CEP program? What will the loan program's features be if it is to contribute to a successful CEP?
- (f) Please provide details of any conversations or written exchanges between EGD and the provincial government on the CEP program since the 2015 budget announcement, including copies of any emails.

5. *Ref: Page 2*

EGD defines a Small Main Extension Project as "all other forms of distribution expansion which produce first time natural gas system access to customer".

- (a) Please provide more detailed explanation, especially of the phrase "natural gas system access".

- (b) Does this definition include service laterals from existing mains? Please explain.
- (c) How many customers must gain access to gas to qualify as a small main extension?
- (d) How are "Small Mains" defined in the context? Please provide examples to illustrate the dividing line between small main and services, and between small mains, medium mains, and large mains, including, inter alia, pressures and pipe diameters and any other differentiating characteristics.

6. **Ref: Page 5, Paragraph 6**

How should those new customer contributions, by way of monthly payments, be treated for ratemaking purposes? Please explain fully. Would the payments over the plan term be discounted and used to reduce rate base in year one, or would they be deducted from rate base in the year in which they were made?

7. **Ref: Page 6, Paragraph 4(b)**

What annual normalized reinforcement has EGD included in its calculation of the capital costs for its proposed expansion? How are the amounts of these cost forecasts derived? What have actual reinforcement costs been in each of the last three years?

8. **Ref: Page 6, Issue #4(a)**

Why, in EGD's view, is it fair to ask existing EGD customers to subsidize the expansion of service to new communities through projects that have a P/I lower than 0.8%, which is

already a subsidy? Why should this not be a role for the government of Ontario, through its recently announced program?

9. **Ref: General**

In its 2016 budget, the Ontario government states:

"The Province is also developing programs to help communities partner with utilities to extend access to natural gas supplies. Ontario will introduce a loan program to support access to natural gas in 2016. Access to natural gas can help stimulate the economy, particularly in smaller communities, by attracting new industry, making commercial transportation more affordable, benefiting agricultural producers and providing consumers with more energy choices" (p63).

- (a) Given that the province, in its 2016 budget, at page 63, appears to have dropped the grant component of the rural gas expansion program, announced in its 2015 budget, and given that the province has in more than a year later not developed any criteria for the loan or grant parts of its policy, would EGD agree with BOMA that the province no longer has a "policy" of facilitating gas service for unserved communities in Ontario? If EGD disagrees, please explain what that policy is either than a preference that existing gas customers subsidize the uneconomic expansion to unserved areas.
- (b) In EGD's view, does the OEB have the authority to order the gas utilities to pursue uneconomic expansion to unserved parts of the province?

10. **Ref: Page 7 of 36**

The stage 2 benefits referred to in the EBO 134 Guidelines are for gas transmission projects. It is generally agreed that without such a construct, there would be no major

transmission reinforcements possible. However, for distribution expansions to connect additional communities, EBO 188 is a well-developed test, which EGD supports. Why is EGD purporting to use the EBO 134 Guidelines for distribution expansion? Why is it appropriate to use these tests in a project-specific assessment of distribution expansion projects. Does EGD agree that using these second stage benefits could be used to justify any expansion to unserved communities in the province, no matter how remote the communities are from existing gas infrastructure.

11. **Ref: Page 7, Paragraph 25**

- (a) What percentage of customers in each unserved community would likely attach after the initial ten year attachment forecast horizon? Please support this answer with data from other EGD's experiences, and identify the expansion projects relied upon.
- (b) Please quantify the incremental revenue that would be generated by the customers referred to in (a) above, and the "economics of sale" achieved by the company due to the project in the thirty-nine communities, both in absolute terms and percentage of EGD's revenue requirement. Please discuss thoroughly, and specify what unit costs would be reduced because of economics of scale, and by how much.

12. **Ref: General**

Does EGD agree with Union that the Community Energy Project is not a Z-factor?

13. *Ref: Page 9, Paragraph 31*

- (a) Will the ratepayers' funds paid in rates, in the event the costs for particular projects were less than forecast, be returned to ratepayers? How would this happen?
- (b) Please confirm that under the Y-factor treatment proposed by EGD for the \$410 million CEP capital costs, existing utility ratepayers would be responsible for the payment of any cost overruns relative to forecasts of the capital costs on the community expansion projects and the incremental rate base and revenue requirements that would result. If so, please explain in what circumstances utility ratepayers would not be responsible.
- (c) EGD has stated that it should not be at risk for the expansion program. Why should EGD shareholders be held harmless from liability for any cost overruns and against any other risks which materialize in the expansion programs, when they will be a major beneficiary of the program?

14. *Ref: Page 9*

Please provide a timetable for the implementation of the first few projects in the event the Board were to approve the proposed program on terms acceptable to EGD by September 2016. Please identify which projects, from EGD's list of projects, would proceed first and why, and the implementation timetable for each such project. Over what period of time would EGD propose to construct the remaining projects?

15. ***Ref: Page 10, Paragraph 33***

Is it EGD's view that the new entrants should demonstrate their qualifications to run a gas distribution business in this proceeding or in some future proceeding, for example, a leave to construct hearing? Please explain fully. Is it EGD's view that a party seeking to distribute gas to an unserved area in Ontario must already be in the gas distribution business in another jurisdiction, and if so, why? Please explain fully.

16. ***Ref: Issue 10, Page 11, Paragraph 43***

Please explain how the typical residential electricity user will see a monthly saving of \$2.00 per month due to the implementation of cap and trade.

17. ***Ref: Issue 10, Page 11, Paragraph 43***

Given the announced provincial cap and trade policy, why would EGD include residential customers now using electricity to be part of a group eligible for conversion to natural gas?

18. ***Ref: Page 11, Paragraph 35***

Please describe in detail EGD's efforts over the last several years to advance fuel switching to natural gas in the Transportation Sector.

19. ***Ref: Page 11, Paragraph 36, Issue 10***

Please provide the forecast reduction to Greenhouse Gas ("GHG") reduction in Ontario over the next ten years that would result from implementation of EGD's expansion

proposal. What percentage of Ontario's 2030 GHG target reduction would the reduction be?

20. **Ref: Issue 10**

What is EGD's estimate (or measured amount) of the amount of GHG emissions resulting from methane emissions from its natural gas operations in Ontario currently, including emissions from pipelines, compressors, storage facilities, and all other equipment? Does EGD measure such emissions? Please discuss in detail. What quantitative targets, if any, does EGD have to reduce such methane emissions over the next few years? What additional methane and GHG emissions would result from the proposed CEP?

21. **Ref: Page 15, Paragraph 48**

Please explain the meaning of "non-exhaustive list of these communities". What other communities are on EGD's list for future expansion, as part of its proposed program?

22. **Ref: Page 17, Paragraph 51**

- (a) Please provide a description of the terrain, the number of river crossings, temperature, and distance for each of EGD's forty proposed expansion proposals. Which of the forty projects would EGD characterize as being across "difficult terrain"?
- (b) Please provide a comparison of the average distance between an existing main and the twenty-nine and forty communities proposed in the Union and EGD expansions.

- (c) Please describe the characteristics of "easy" versus "difficult" terrain with respect to the proposed expansion.

23. *Ref: Page 17, Paragraph 50*

Please provide the threshold percentage of transmission main costs relative to total project costs that triggered the examination of LNG as a more economically attractive solution.

24. *Ref: Page 17, Paragraph 52*

- (a) Please explain in detail why none of EGD's thirty-nine potential projects would achieve Project Profitability greater than or equal to 0.4 test used under Union's proposal even after the new customer contributions and municipal contributions. Please deal with each of the thirty-nine projects.

- (b)
 - (i) How many of the thirty-nine projects are for municipalities in which EGD already has a Franchise Agreement? If there are some, for how long as EGD had each such franchise agreement?
 - (ii) Does Union also have a Franchise Agreement with any of them?
 - (iii) Are any of the thirty-nine projects closer to Union's infrastructure than to EGD's infrastructure? Which ones, and what is the difference in distance?
 - (iv) In how many of the thirty-nine municipalities has EGD obtained Certificates of Public Convenience and Necessity? When was each of the Certificates obtained?

25. **Ref:** *Page 20, Paragraph 57*

- (a) What are the "contingencies" built into the cost estimates for each of the thirty-nine projects in both dollar and percentage terms? By how much is the contingency amount for each of the projects expected to be reduced, once (i) detailed design; and (ii) tendering for each of the projects has been completed? What impact would that have on the weighted average "natural P/I" for the thirty-nine projects?
- (b) Will the contracts for the work be on a fixed price basis? If not, on what basis?
- (c) What is the forecast average cost per home of connecting the 16,000 homes compared with the average cost of connecting Union's 18,000 homes (twenty-nine communities), as provided in their evidence?

26. **Ref:** *Page 20, Paragraph 58*

In community expansion projects in the past ten years, please provide a comparison of EGD's forecast and actual costs of expansion programs, together with the actual versus forecast conversions for the ten year period, with reference to OEB case numbers in cases where leave to construct was required.

27. **Ref:** *Page 21, Paragraph 59*

What is EGD's forecast of Small Main Expansion revenue that would accrue from the Small Main Expansion program over the period of the Community Expansion Program? How would that forecast revenue compare with the revenue collected under current rules? Under current rules, what are the costs of Small Main Expansion projects over each of the

last five years? Has each project been done at P/I of between 0.8 and 1.0? Please discuss fully.

28. **Ref: Page 21, Paragraph 59**

What is the amount of cross-subsidization, both in dollar terms and in terms of percentage of total expansion cost over the first ten years of the program, and of the incremental revenue requirement for the thirty-nine projects, from the existing customers, on the assumption that a new portfolio is established for the thirty-nine new projects, with the requirement that the "portfolio rolling P/I" will be maintained at 0.5 for the first ten years of the program. Please confirm that the new portfolio will be in the regulated part of EGD and any shortfall in revenue for that portfolio compared to a portfolio with a profitability of 1.0 will be covered by the existing customers.

29. **Ref: Page 23, Paragraph 69**

What is the weighted (by dollar amount) average profitability ratio of the thirty-nine proposed community expansion projects.

30. **Ref: Page 23, Paragraph 69**

(a) Please explain the difference in quantitative terms of "focusing attention on the overall impact on all ratepayers as opposed to targeting the economic feasibility test of specific projects". Is the overall negative impact on existing ratepayers (at the time the expansion is being proposed) not simply the sum of losses incurred on each of the new projects weighted by the dollar amounts of the projects? Please explain fully.

- (b) Why does a separate rolling project portfolio managed to a minimum P/I of 0.5 require less subsidy from existing ratepayers than requiring each individual new community expansion project to have P/I of at least 0.5? If not, please explain the difference between the two approaches.
- (c) Please provide a copy of EGD's distribution system expansion guidelines or its equivalent.

31. **Ref: Page 24, Paragraph 72**

BOMA wishes to know the feasibility of the proposed implementation schedule. Please indicate which of the thirty-nine proposed projects would be completed in each year of the first five years and the total capex for the projects in each of those five years. Please state which two projects will be completed in year one and the total capex. Please explain the scheduling for the two year one projects, assuming a Board approval in September 2016, and for each subsequent group of projects in years two through seven.

32. **Ref: Table 7**

Please provide an extension of Table 7 for ten years beyond year eight.

33. **Ref: Page 30**

- (a) Please provide a revised Table 7, with the ten projects with the lowest P/I excluded from the program.
- (b) Please provide a revised Table 7, with the twenty projects with the lowest P/I were excluded.

- (c) Please provide a revised Table 7 assuming a fifteen percent cost overrun across all projects.
34. **Ref: Page 25**
- (a) What is the termination date of EGD's current five-year IRM program?
 - (b) Assuming a Board decision in September 2016, on terms acceptable to EGD, please provide a likely schedule of capital expenditures for community expansion projects for 2016 (if any), 2017, 2018, 2019.
35. **Ref: Page 25, Paragraph 76**
- (a) EGD has proposed Y-factor treatment for its capital expenditures. What would the impact of this approach be on EGD's revenue requirement for each year remaining in the IRM program?
 - (b) Why would EGD require Y-factor treatment beyond the end of the current IRM? Please explain fully.
36. **Ref: Page 25, Paragraph 77**
- (a) Which of the thirty-nine projects would require leave to construct applications? What other mechanism would be required for approval of the projects that did not require a leave to construct. Would they be included in the annual rate adjustment application for each of the remaining years of the IRM program? Please discuss.
 - (b) For the last ten years, for each distribution or transmission expansion project, including the GTA project most recently discussed at EGD's Stakeholder Consultation, that requires leave to construct:

- the capital budget forecast;
- the contingency factor in the capital budget forecast;
- the actual capital costs compared to the forecast capital cost, including the contingency;
- how any cost overrun or underspend was, or will be, treated in rates.

37. *Ref: Page 26*

Please provide the capital cost per km of distance from the gas main from which the new line would originate for each of the thirty-nine communities, rank ordered from lowest to highest.

38. *Ref: Page 26, Table 4*

For each of the thirty-nine projects, please provide the "business case", including the geographic location of, and whether any industrial customers will be among the customers connected, and generally the likely economic development impacts of each of the thirty-nine projects. For example, in how many instances would the "supply of gas" be to an existing manufacturer in a competitive sector of the economy and currently on a more expensive fuel in any of the thirty-nine projects? Which company(ies)? How many jobs does the company(ies) support?

39. *Ref: Page 26, Table 4*

For each of the Fenelon Falls and Scugog Island projects, if EGD has included a substantial number of new customers (rather than conversions), please provide the analysis on which the numbers of new customers are based.

40. *Ref: Page 26, Table 4*

Given the agreed cut-off is fifty customers, why are the two communities Fifth Line and Chute-A-Blondeau, with twenty-four and forty-eight conversions, respectively, included in the list?

41. *Ref: Page 26*

To what extent has the potential growth of a "community" been factored into the project priority list? Has this been done, as part of the analysis?

42. *Ref: Page 26, Table 4*

What is the total investment in the pipeline connection for each of the thirty-nine municipalities?

43. *Ref: Page 27, Table 5*

Please confirm that the figures in column 14 are the capital contributions required from the community, the new customers, and/or the province in order to increase the P/I from what it would be under the EGD proposed program of new customer payments and the municipal subsidy, all as shown in column 13, to a P/I of 0.8. Please explain fully.

44. *Ref: Page 29, Table 6*

(a) Please provide the underlying analysis for the Annual Capital Subsidy for LNG for each of the nineteen communities EGD proposes to serve with LNG, as derived from the cost of the LNG capital investment for each community.

(b) Please provide the analysis underpinning the Annual Gas Subsidy assuming EGD purchased the LNG from a third party on a delivered basis for each of the

communities. Please show separately the assumed commodity cost and the delivery charge for the LNG.

- (c) Please discuss the allocation of risk in the contracts EGD would have with the third party LNG supplier. Can EGD provide a prototype of the proposed contract?
- (d) Has EGD conducted an analysis to confirm the availability of LNG in Ontario once the time period in question, and the prices for which such LNG supply could be contracted? Please explain the results, and if no analysis has been done, why not?

45. *Ref: Page 32 of 36, Table 9*

- (a) Table 9 shows only one industrial project among the thirty-nine municipalities. Does this mean there is only one manufacturer in the thirty-nine communities at this time; one manufacturer that competes with others outside Ontario; competes with other manufacturers of the same product inside Ontario?
- (b) Please compare the average cost per residential customer, and commercial customer, as shown on Table 9 with the overall cost (capital and O&M) per customer.

46. *Ref: Page 32, Table 9*

Please provide the working papers used to derive the numbers on each line and column of Table 9, as well as the bill impact numbers shown on paragraph 95.

47. **Ref:** *Page 20 of 38*

Does EGD agree that in order to capture the public interest aspects of proceeding with a community expansion project, the impact of the project on GHG emissions should be considered, including efforts to mitigate such GHG impacts?

48. **Ref:** *Issue 8*

(a) Does EGD agree that a new entrant should be able to charge higher rates than currently approved Union or EGD rates to its customers in a currently unserved area, if that it is necessary for that entrant to earn a compensatory return on capital? If not, why not? Could it charge lower rates than existing EGD and Union rates if it could still earn its return?

(b) Does EGD think that it would be, or could be, in the public interest to have more than the current gas distribution utilities, active in Ontario? Please discuss fully.

(c) **Ref:** *Page 33*

(i) Does EGD believe that the addition of new customers could reduce O&M costs as a result of the larger base over which to spread fixed costs on a per customer basis? Please explain why. Which fixed costs of overall administrative support capability would be more widely spread?

(ii) By how much?

49. *Ref: General*

Does EGD think that the Board should become more heavily engaged in the process to choose a new supplier for an unserved community using RFPs or otherwise? If so, please explain the process EGD would envisage.

PART B UNION GAS

50. *Ref: Union Gas Submission*

Has Union considered any options for existing customers other than a rate rider, which will attract payment of HST in addition to the rate rider itself, thereby adding an additional 13% to costs associated with the rate rider? If so, please file the results of the analysis. If not, why not? Over the timeframe estimated for the collection of the rate rider from existing customers what will be the total provincial share of the HST revenue?

51. *Ref: Union Gas Submission*

With respect to the ICF study for the Canadian Gas Association, why does Union assume the results for Canada as whole can be assumed to apply to Ontario, given that Ontario's electricity system has been significantly decarbonized already?

52. *Ref: Union Gas Submission*

With respect to the average rate impacts being limited to \$2.00 per month, BOMA Toronto assumes that this amount is the average for a residential or general service customer. What is the estimate of the total rate impact for Union other customer classes, by rate class per month and for the lifetime of the community expansion projects included

in Union's submission?

53. **Ref: Issue 12**

In its 2016 budget, the Ontario government states:

"The Province is also developing programs to help communities partner with utilities to extend access to natural gas supplies. Ontario will introduce a loan program to support access to natural gas in 2016. Access to natural gas can help stimulate the economy, particularly in smaller communities, by attracting new industry, making commercial transportation more affordable, benefiting agricultural producers and providing consumers with more energy choices" (p63).

- (a) Does Union agree that in the 2016 budget (page 63), while the \$200 million loan program, introduced in the 2015 budget, is reaffirmed, there is no reference to the \$30 million grant program?
- (b) In Union's view, has the province dropped the grant program?
- (c) In Union's view, why has the province not yet developed criteria for the loan/grant program, given that the program was first announced in the 2015 budget?
- (d) When does Union anticipate the provincial program will become operational?
- (e) What is Union's view as to how the loan program will fit into the CEP program, who will receive the loans, what features must the loan program have to contribute to a successful CEP?
- (f) Please provide details of any conversations or exchanges in writing between Union and the provincial government on the CEP program since the 2015 budget announcement.

- (g) Given that the province, in its 2016 budget, at page 63, appears to have dropped the grant component of the rural gas expansion program, announced in its 2015 budget, and given that the province has in more than a year later not developed any criteria for the loan or grant parts of its policy, would Union agree with BOMA that the province no longer has a "policy" of facilitating gas service for unserved communities in Ontario? If Union disagrees, please explain what that policy is either than a preference that existing gas customers subsidize the uneconomic expansion to unserved areas.

54. *Ref: Page 20 of 38*

Does Union agree that in order to capture the public interest aspects of proceeding with a community expansion project, the impact of the project on GHG emissions should be considered, including efforts to mitigate such GHG impacts?

55. *Ref: Page 20*

- (a) Has Union made an assessment of the economic impact of connection to natural gas for an industrial customer currently using oil, propane, or electricity as a major objective of the CEP program is economic development in smaller communities and rural areas?
- (b) Please provide a list of the industrial customers in each of the targeted communities that would be eligible to connect to natural gas for (i) heating; or (ii) process purpose. How many of the industrial customers compete with companies outside Ontario?

- (c) Does Union agree that allowing community expansion projects to proceed with P/Is as low as 0.8, so long as the rolling portfolio P/I remains at 1.0 is itself a subsidy from existing ratepayers.

56. *Ref: Page 21, Issue 4(f)*

Union states in its evidence that it has only used EBO 134 in applications to expand the Dawn Parkway and Ojibway transmission systems. Does Union agree that EBO 134 remains a construct to facilitate expansion of these high pressure, long line transmission systems are essential to the operation of the Union integrated transmission/distribution business, and was not designed to be used for distribution system expansion projects? However, for distribution expansions to connect additional communities, EBO 188 is a well-developed test, which Union supports. Why is Union purporting to use the EBO 134 Guidelines for distribution expansion? Why is it appropriate to use these tests to support a project-specific assessment of distribution expansion projects. Does Union agree that using these second stage benefits could be used to justify any expansion to unserved communities in the province, no matter how remote the communities are from existing gas infrastructure.

57. *Ref: Page 24*

Union states that:

"It is Union's position that the Board should avoid, where possible, prescriptive ratemaking approaches, and allow utilities to bring forward rate proposals that can be reviewed on their merits".

What does Union mean by "prescriptive ratemaking approaches", as used in the quoted sentence? Please provide examples of such "prescriptive" approaches and why Union does not favour them, or is opposed to them.

Does Union believe it is necessary or desirable to have uniform gas distribution rates across the province?

58. *Ref: Issue 7*

Union has stated that they should not be at risk for the expansion program. Why should Union's shareholders not be at risk with respect to recovery of capital expenditures for the community expansion projects, given that expenditures will increase Union's rate base and its revenue requirement, both of which will benefit Union? Please explain fully.

59. *Ref: Issue 8*

(a) Does Union agree that a new entrant should be able to charge higher rates than currently approved Union or EGD rates to its customers in a currently unserved area, if that it is necessary for that entrant to earn a compensatory return on capital? If not, why not? Could it charge lower rates than existing EGD and Union rates if it could still earn its return?

(b) Does Union think that it would be, or could be, in the public interest to have more than the current gas distribution utilities, active in Ontario? Please discuss fully.

(c) **Ref: Page 33**

(i) Does Union believe that the addition of new customers could reduce O&M costs as a result of the larger base over which to spread fixed costs on a per customer basis? Please explain why. Which fixed costs of overall administrative support capability would be more widely spread?

(ii) By how much?

(c) Why does Union think it is necessary for the new entrants to get Board approval of rates before signing (or getting Board approval for) a franchise agreement with a municipality?

60. **Ref: Pages 26-28**

Why does Union think that the Board should become more heavily engaged in an RFP process to choose a new supplier for an unserved community? If so, please explain the process Union would envisage.

61. **Ref: London Economics ("LE") Study (Schedule 1)**

Does LE agree that given the source make-up of Ontario electricity production, conversion of residential customers from electricity to gas conflicts with, rather than aligns with, Ontario's GHG policy goals? If not, why not?

62. **Ref: Schedule 1, Page 2**

(a) Did LE in its high level review of North American gas and electricity markets examine the funding mechanism for expansion in all U.S. states and Canadian provinces in sufficient detail to conclude that all of the mechanisms used fell into

one of the four categories outlined in Figure 1? If not, please explain. Does each jurisdiction have some mechanism or process for dealing with expansion? Do some jurisdictions have no set process? How do these jurisdictions deal with the issue?

- (b) How were the jurisdictions for more detailed analysis chosen?
- (c) Does Union or LE have a view on why each of the provinces/states chosen for detailed study have legislation which underpins the formal process for funding gas distribution expansion in their province/state (our emphasis)? Were there any judicial decisions that required the legislation?

63. **Ref: *Ibid, Page 10, Reports to the Board of Selected Project Performance***

- (a) Please provide the projects selected for their Rolling Projects Portfolio and reported to the Board for showing the customer attachments at the end of the third full year, the associated revenues and costs, and the third year forecasted performance for each of the last five years.
- (b) How were the projects selected to ensure they are representative?

64. **Ref: *Ibid, Page 20, New York***

Please provide copies of, or a link to, New York Public Service Law, Section 68.

65. **Ref: *Ibid, Page 21***

- (a) Please explain how the surcharge is calculated under New York legislation.
- (b) Does New York have the equivalent of EBO 188? Please discuss.

- (c) Please confirm that the exceptions granted in 89-G-078 did not increase the amount of the surcharge but simply allowed for its collection over a ten year period, rather than a shorter period to ease the burden on the new customers.
- (d) Please confirm that the collection of a rate surcharge from "all customers in the new area" is only permitted to the extent that the forecast expansion project cost shows that at the end of a five year period, without such charges, the rate of return of the utility will be below its allowed rate. If not, please explain.
- (e) What would be the impact on the Union proposal of using the New York test?
- (f) Does LE agree that comparison between gas and electricity service should be conditioned by the absolute need for electricity to run a modern home or business, as it essentially has no substitutes? In other words, electricity is a must have, gas is a "nice to have".
- (g) In all of the cases discussed by LE, except New York, the jurisdiction has enacted legislation to facilitate the expansion of gas or electric utilities into rural, farm, or other underserved area. Is LE of the view that specific legislation in Ontario, which codified government support for rural expansion, would lead to a more orderly, comprehensive development of an Ontario program?

66. *Ref: Union, Red Lake Expansion*

In the Red Lake expansion case (EB-2011-0040), please confirm that Goldcorp Inc. paid a contribution-in-aid of over \$20 million to make the expansion feasible. The contribution was paid in several payments. Please confirm that the Goldcorp Inc.

payments to Union resulted in commensurate reduction to Union's increase in rate base for the project.

67. **Ref:** *Application, EB-2015-0179, Updated, Exhibit A, Tab 1, Page 2*

How should those new customer contributions, by way of monthly payments, be treated for ratemaking purposes? Please explain fully. Would the payments over the plan term be discounted and used to reduce rate base in year one, or would they be deducted from rate base in the year in which they were made? Please explain any administrative problems that would make the deduction of the annual contribution amount at the end of each year, or as a reduction from opening rate base in the following year unusually deficient, and if there is such a problem, how it would be solved, if the Board were to direct that course of action.

68. **Ref:** *Ibid, Page 6*

What annual normalized reinforcement has Union included in its calculation of the capital costs for its proposed expansion? How are the amounts of these cost forecasts derived? What have actual reinforcement costs been in each of the last three years?

69. **Ref:** *Ibid, Page 2*

Why, in Union's view, is it fair to ask existing Union customers to subsidize the expansion of service to new communities through projects that have a P/I lower than 0.8%, which is already a subsidy? Why should this not be a role for the government of Ontario, through its recently announced program?

70. **Ref:** *EB-2016-0004, Exhibit A, Tab 1, Page 33*

- (a) What percentage of customers in each unserved community would likely attach after the initial ten year attachment forecast horizon? Please support this answer with data from other Union's experiences, and identify the expansion projects relied upon.
- (b) Please quantify the incremental revenue that would be generated by the customers referred to in (a) above, and the "economics of sale" achieved by the company due to the project in the twenty-nine communities, both in absolute terms and percentage of Union's revenue requirement. Please discuss thoroughly, and specify what unit costs would be reduced because of economics of scale, and by how much.

71. **Ref:** *EB-2015-0179, Updated, Exhibit A, Tab 1, Page 2*

- (a) Will the ratepayers' funds paid in rates, in the event the costs for particular projects were less than forecast, be returned to ratepayers? How would this happen?
- (b) Please confirm that under the Y-factor treatment proposed by Union for its CEP capital costs, existing utility ratepayers would be responsible for the payment of any cost overruns relative to forecasts of the capital costs on the community expansion projects and the incremental rate base and revenue requirements that would result. If not, please explain in what circumstances utility ratepayers would not be responsible.

72. **Ref: *Ibid, Page 32***

Please provide a timetable for the implementation of the first few projects in the event the Board were to approve the proposed program on terms acceptable to Union by September 2016. Please identify which projects, from Union's list of projects, would proceed first and why, and the implementation timetable for each such project. Over what period of time would Union propose to construct the remaining projects?

73. **Ref: *EB-2016-0004, Exhibit A, Tab 1, Pages 26-28***

Is it Union's view that the new entrants should demonstrate their qualifications to run a gas distribution business in this proceeding or in some future proceeding, for example, a leave to construct hearing? Please explain fully. Is it Union's view that a party seeking to distribute gas to an unserved area in Ontario must already be in the gas distribution business in another jurisdiction, and if so, why? Please explain fully.

74. **Ref: *EB-2016-0004, Exhibit A, Tab 1, Page 35***

Please provide the forecast reduction to Greenhouse Gas ("GHG") reduction in Ontario over the next ten years that would result from implementation of Union's expansion proposal. What percentage of Ontario's 2030 GHG target reduction would the reduction be?

75. **Ref: *Ibid***

What is Union's estimate (or measured amount) of the amount of GHG emissions resulting from methane emissions from its natural gas operations in Ontario currently,

including emissions from pipeline services, compressors, storage facilities, and all other equipment? Does Union measure such emissions? Please discuss in detail. What quantitative targets, if any, does Union have to reduce such methane emissions over the next few years? What would be the additional methane emissions that result from the proposed CEP?

76. *Ref: General*

- (a) What are the "contingencies" built into the cost estimates for each of the twenty-nine projects in both dollar and percentage terms? By how much is the contingency amount for each of the projects expected to be reduced, once (i) detailed design; and (ii) tendering for each of the projects has been completed? What impact would that have on the weighted average "natural P/I" for the twenty-nine projects?
- (b) Will the contracts for the work be on a fixed price basis? If not, on what basis?
- (c) What is the forecast average cost per home of connecting Union's 18,000 homes (twenty-nine communities)?

77. *Ref: Page 20, Paragraph 58*

In community expansion projects in the past ten years, please provide a comparison of Union's forecast and actual costs of expansion programs, together with the actual versus forecast conversions for the ten year period, with reference to OEB case numbers in cases where leave to construct was required.

78. *Ref: Page 24, Paragraph 72*

BOMA wishes to know the feasibility of the proposed implementation schedule. Please indicate which of the twenty-nine proposed projects would be completed in each year of the first five years and the total capex for the projects in each of those five years. Please state which two projects will be completed in year one and the total capex. Please explain the scheduling for the year one projects, assuming a Board approval in September 2016, and for each subsequent group of projects in years two through seven.

PART C EPCOR

79. *Ref: Page 20*

Does EPCOR agree that the electricity service for the small town and rural residential or business customers is a "must have", while natural gas is a "nice to have"? Please discuss.

80. *Ref: Page 22*

Would you agree that if the province continues to state that it has not yet developed criteria for the loan/grant program, this regulatory initiative should be put on hold until the province develops the criteria for its loan and grant program, and is ready to disburse funds? Please discuss fully.

81. *Ref: Page 23*

- (a) Do you agree that the 2016 Ontario budget refers to project expansion loans, but not grants?
- (b) Has the province discussed with you what the criteria for grants to expansion projects would be? Criteria for loans?

- (c) Is it your understanding that the province has dropped the grant component of its promised program?

82. **Ref: Page 23**

- (a) What does EPCOR say the amount of the "small volumetric levy on province-wide sales of natural gas to current customers" should be? Please discuss.
- (b) Why should new entrants in the gas distribution business not be required to finance their own business growth in Ontario, subject to contributions from a provincial loan or grant, just as any other business would be required to do? Is it not the case that in competitive markets, customers of the new entrant's established competitors are not required to contribute to the establishment of the new entrant's business?
- (c)
 - (i) Is EPCOR proposing that it should be able to bid on existing built out franchises as they come up for renewal?
 - (ii) If so, how would EPCOR deal with the issue of the incumbent utility's stranded costs if new entrants were allowed to compete for municipal franchises on their renewal date when the incumbent has already built out the franchise?

PART D SOUTH BRUCE

83. *Ref: The approach and competitive solicitation process undertaken by the Municipalities to facilitate the expansion of Natural Gas Service to Southern Bruce County, March 21, 2016*

Did the franchise agreements signed by the three municipalities with EPCOR depart in any way from the existing Model Franchise Agreement? If so, how? Please make copies of these franchise agreements available. When will the municipalities or EPCOR submit the franchise agreements to the Board for approval?

84. *Ref: Ibid, Page 2*

Do the municipalities have any commitments from EPCOR in the franchise agreement or otherwise, as to what its rates will be if it obtains the franchise for the municipalities?

PART E NORTHEASTERN MIDSTREAM

85. *Ref: Page 4*

Please confirm that FortisBC will produce the LNG that it supplies to its customers in Whistler and Revelstoke.

86. *Ref: Page 5*

Can you provide an example(s) of a northeastern U.S. LDC:

- (a) That uses LNG in conjunction with piped natural gas to show the basis on which LDC rolls in the cost of the LNG into its WACOG, the impact that has on the WACOG, and regulatory approval for that approach.

- (b) Do these examples deal with the use of LNG earmarked for expansion into unserved areas, eg. rural or small communities, as is being considered in this case, or are they more in the nature of supplemental supplies to pipeline supplied gas service to the utility's existing service area (increased demand within the area to which the utility already serves)? Please discuss fully.

PART F GREENFIELD SPECIALTY ALCOHOLS INC.

87. *Ref: Page 2*

Please describe the commercial arrangements under which GreenField acquires its supply of steam from Bruce Power. Does GreenField have what is in effect a tolling arrangement with Bruce Power? In other words, it supplies Bruce Power with CNG and pays a fee for it to be converted to steam and returned? Please discuss.

88. *Ref: Page 3*

- (a) If GreenField's Tiverton plant were to acquire pipeline gas from Union pursuant to an expansion, what would its annual delivered cost of gas be, and how would that compare to an energy equivalent basis to its gas costs plus fee to Bruce Power for producing steam and delivering it to GreenField? What would be the minimum term available for GreenField pursuant to the applicable rate? What infrastructure would GreenField need to install, for example a gas-fired boiler? What would the retrofit cost be?

- (b) Does GreenField have a minimum contract term with Bruce Power, comparable to the term Union would require? What about comparable "minimum-take" provisions?
- (c) Has GreenField had discussions with other companies that propose alternative pipeline projects or other alternative delivery arrangements, eg. CNG or LNG to its facility? How do their rates compare with the cost of GreenField's current energy costs?
- (d) Does GreenField own the Mt. Forest compressor and the truck fleet?
- (e) How does GreenField assess the risks of switching from its current CNG/Bruce Power supply arrangements to alternative arrangements, either pipeline or otherwise?
- (f) Under what circumstances would GreenField serve as an anchor load for a new pipeline project?