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Our File No. 134622

April 22, 2013

VIA RESS, EMAIL AND COURIER

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

Attention: Kirsten Walli,
Board Secretary

Dear Ms. Walli:

Re: BOMA's Submission - Board File No. EB-2012-0459

Please find enclosed herewith BOMA's Submission.

Yours truly,

FOGLER, RUBINOFF LLP

Tom Brett per: [illegible]

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

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EB-2012-0459

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

AND IN THE MATTER OF an Application by Enbridge Gas Distribution Inc. for an order or orders approving or fixing rates for the sale, distribution, transmission and storage of gas commencing January 1, 2014.

Submissions of Building Owners and Managers Association, Greater Toronto ("BOMA")

A. Enbridge's Customized IR Plan

1. Is Enbridge's proposal for a Customized IR plan for a 5 year term covering its 2014 through 2018 fiscal years appropriate?

EGD's proposal for a Customized IR Plan for a five year term covering its 2014 through 2018 fiscal years (the "EGD Plan") is not appropriate because it does not result in rates over that period that are just and reasonable.

Those rates are not just and reasonable because:

(a) they result in increase in rate increases over the 2014, 2015, 2016 period that are unreasonably high and because there is not sufficient information provided for the years 2017 and 2018, years four and five of the EGD Plan, to determine whether the rates in those two years are just and reasonable (the numbers used for both capital and O&M expenditures are placeholders). While rates in 2014 relative to 2013 decline slightly due to the capital cost allowance impact from large capital expenditures, the rate increases in 2015 and 2016 relative to 2014 rates are, for rate 1 (residential users) 2.1% and 4.6%, respectively. For rate 6 (commercial customers) the rate increases are 1.6% and 4.5%, respectively. (ExH, T1, Sch 1, Appendix A). These increases can be compared, unfavourably, to Union's forecast formulaic rate increase of 0.8% per year over the same five year IRM period. Given the uncertainties about costs, and the proposed multiple deferral accounts, rates in 2017 and 2018 are not clear. EGD estimates them to be at 2.4% and 2.5% for rate1 and 2.4% and 2.5% for rate 6 (ExH, T1, Sch 2, Appendix A, p1). For rate 6, of great interest to BOMA, the proposed five year rate increase is:

2014	2015	2016	2017	2018
-0.8%	1.6%	4.5%	2.4%	2.5%

These numbers do not include the impacts of the proposed broadening of the Z-factor window, the use of deferral accounts for the GTA and for potential large capital expenditures on integrity and reliability in 2017 and 2018;

(b) but for the proposed allocation of the SRC refunds to customers over the IRM term, the increase in customers' bills are also unreasonably high. As explained below, the Board should not take into account these refunds in assessing the EGD Plan as they are a refund of funds that EGD has already collected in rates since 1959 which have been deemed surplus to EGD's SRC requirement, as determined by Gannett Fleming, and EGD has stated that they should be considered on a stand-alone basis (TR. 4. p157);

(c) the EGD Plan increases the risk to ratepayers of paying still higher rates, especially in 2017 and 2018. EGD's senior management notes, in its April 30, 2013 memorandum to the EGD Board, as part of its justification for what was then a three year IRM Plan:

> "In addition, given that there is uncertainty around the outcome of a number of important integrity studies currently underway and their impact on capital spending requirements beyond 2016, Management concluded that it is appropriate to pursue a 3 year term versus the 5 year term of the 1st Generation IR Plan" (our emphasis) (I.A1.EGDI.CCC.2).

Ultimately, EGD decided to amend its evidence to propose a five year plan but with a deferral account for system integrity and reliability expenditures, which creates a new large risk for ratepayers.

(d) the EGD Plan also shifts risks to ratepayers to an unacceptable degree in several ways.

First, the rates are calculated based on a forecast of the cost of service and returns for each of the years 2014, 2015, 2016, 2017 and 2018. These costs include depreciation, O&M taxes, and return. However, aside from the proposed GTA variance account, there is no true-up proposed in the event that the forecast capital expenditures and rate base are not realized in any particular year. For example, if rate base is forecast to increase \$200 million in a particular year but the actual increase is only \$100 million, the "allowed revenue", or "revenue requirement", as the Board describes[1] it would remain based on the \$200 million. As a result,

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[1] In the Renewed Regulatory Framework for Electricity Distributors: A Performance Based Approach, at p.18 (the RRRF Report) the Board states: "In the Custom IR method, rates are based on a five year forecast of a distributor's revenue requirement and sales volumes."

ratepayers would be paying in rates for return on, and depreciation of, assets that do not yet exist. Assets that do not exist cannot be said to be used or useful, and it is not reasonable for customers to pay for them in rates. Rebasing is not until 2019, and much can happen over that period. The overreliance on forecasts, and failure to true-up, also creates additional volatility in rates.

As Dr. Kaufmann noted in his assessment of the merits of the EGD Plan on behalf of Board Staff (Ex L, T1, Sch 2), the plan creates an incentive to overforecast. At p2, he states:

> "The EGD's Customized IR proposal creates the same perverse ex ante incentives to inflate capital cost projections as the early UK building block plans. Because the <u>Company's capital expenditure forecasts are not supported by independent and external benchmarking evidence</u>, the inherent incentive to inflate these forecasts under the Customized IR proposal can generate unreasonably high prices and shift risks to customers" (our emphasis).

However, unlike an annual cost of service regime, where the ratepayers and the Board could require that the overforecast be corrected in the following year's application, EGD proposes no adjustment until rebasing, five years later.

Ratepayers would not bear this risk under an I-X form of IRM since rates would be increased each year only to the extent permitted by the I-X formula, regardless of the level of capital expenditures. In the event the IRM plan was in the form of I-X plus a capital module (roughly the Toronto Hydro model) the ratepayer protection would be increased by the fact that the rate riders do not become effective until the assets created by the forecast capital expenditures were placed in service (see, for example, EB-2012-0064, Phase 2 Settlement Agreement). While an annual true-up would normally run counter to the objectives of an IRM program, when the true-up is done to neutralize the incentive to overforecast present in the EGD proposal, the integrity of the IRM is enhanced, not diminished.

The second way in which the risk is shifted to ratepayers in the EGD Plan is through the proposed deferral accounts for major capital projects, such as the GTA and Ottawa Reinforcement, and for 2017 and 2018, system integrity and reliability expenditures and replacements. These capital expenditures, taken together, are significant part of the company's capital budget and include the lumpiest and most difficult to predict items. They are also substantial. For example, EGD has forecast system integrity and reliability capital expenditures of $132.2 million, $135.1 million and $141.1 million in 2014, 2015, and 2016, respectively (Ex J.10). EGD believes that it may make large, but as yet undefined integrity and reliability capital expenditures in 2017 and 2018, following the completion of certain studies (I.A1.EGD1.CCC.2), and it wants to protect the shareholder from the risk of exceeding its forecast capital budget.

Due to the proposed deferred accounts for GTA, Ottawa Reinforcement, Relocations, and system integrity and reliability expenditures in 2017 and 2018, EGD is not at risk for capital cost overruns for a substantial part of its five year capital budget, including the major projects, and the projects most susceptible to significant increase.

Third, Fourth, and Fifth, the EGD Plan has shifted risks to ratepayers through its proposals for the SEIM program (see pp 9-14 below), the broadening of the terms of the Z-factor (see pp 25-29 below) and its failure to propose specific sustainable efficiencies over the period of the plan(see below).

Sixth, in order to result in just and reasonable rates for 2014 and beyond, the 2014 rate proposal and the IRM plan need to take into account the overearning that has occurred in the 2013 base year. The 2013 actuals show a sufficiency of $37.8 million in 2013 (Tr V.10, p28).

The base year actuals should be used rather than the 2013 forecast, because 2013 actual expenditures provides the fairest starting point for ratepayers and the company. In the recent Union 2014-2018 IRM Settlement Agreement, approved by the Board in November 2013, Union deducted $4.5 million from the base year, which deduction carried on throughout the five years (a total amount of $22.5 million to compensate for overearnings in 2013). A base year adjustment of $37.8 million needs to be made in this case, regardless of what form of IRM or cost of service plan is ultimately proposed. Having a fair baseline from which to start the IRM plan is an element in the rates in the IRM years being just and reasonable.

Moreover, the flaws in EGD's proposed IRM plan, in particular the rate increases it contemplates and the degree to which it shifts its ratepayers, are highlighted, when contrasted with the Union IRM plan for the same period. That plan was the product of a Settlement Agreement approved by the Board last November.

The Union plan was an I-X type of IRM for the same five year period (2014-2018), a period during which, like EGD, Union had large capital expenditures (Parkway West and Brantford-Hamilton-Kirkwall) for which it received Y-factor treatment, according to criteria to determine when projects qualify. Union is subject to the same OEB regulatory and TSSA reliability and integrity requirements as EGD. Yet Union determined that it was able to manage its business over the next five years under an IRM regime that provided for an external objective allowed price/revenue increase, which used industry wide inflation and productivity numbers and which provided the company some assurance of recovery of prudent expenditures on its two major projects, without subjecting its ratepayers to the incremental risk of overforecasting, the additional risk of overspending by providing the Company with deferral account protection for overspend on its proposed system integrity and reliability capital for 2017 and 2018.

(e) Finally, the EGD's proposed IRM plan is not appropriate because it is, in effect, a five year cost of service plan, rather than an IRM plan. It has many characteristics of a cost of service plan.

First, it builds up its so-called Allowed Revenue (its revenue requirement) from a forecast of the cost of depreciation, O&M, taxes, and returns, for each of the five years of the plan (Ex A2, T1, Sch 1, p4). It uses forecasts extensively, just like a cost of service plan, but whereas Board-approved cost of service rate plans have traditionally had a one year test year, this plan has five test years.

The Board has not approved multiyear cost of service proposals beyond two years, and, as noted, the standard has been one year. The Board declined to consider a three year cost of service proposal by Toronto Hydro in 2012.

Second, it uses deferral accounts to contain its risks of overspending on major projects. These deferral accounts shift the risk of overspending to the ratepayer. The use of these accounts also belie EGD's claim that it is at risk for overspending annual capital budgets and that its assumption of that risk is the greatest difference between its plan and a cost of service plan (Ex A2, T1, Sch 1, p12, par 30). The second difference it claimed was that its plan was a five year plan rather than a one year plan, but this argument fails if the Board decides that the plan is effectively a cost of service plan.

Third, EGD uses the ROE annual adjustment process that the Board established in RP-2009-0034. But that adjustment process was established by the Board to be used in cost of service plans, not IRM plans (Ontario Energy Board Letter and Guidelines Re Cost of Capital Parameter Updates for 2014 Cost of Service Application, November 25, 2013). In addition, it has done an interest rate forecast five years in advance, as opposed to making an interest rate forecast each year as prescribed by the Board in RP-2009-0034.

Finally, it has proposed to broaden the term of the Z-factor to allow it to capture cost increases from any unanticipated cause (see below at p28). The major loosening of the criteria was counter to the Board's stated expectation, that in an IRM plan, the use of Z-factor should be in "limited, well-defined, and well-justified cases only" (Report of the Board from the Natural Gas Forum, p30).

2. *Does Enbridge's Customized IR plan include appropriate incentives for sustainable efficiency improvements?*

The EGD Plan does not provide appropriate incentives for sustainable efficiency improvements, either in its capital budget, O&M budget, or its SEIM proposal, which remains deeply flawed.

(a) Capital

(i) EGD suggests that its capital budget contains sustainable energy efficiencies but does not provide any details, or any list of the individual embedded efficiencies, and the forecast amounts and duration of the cost savings of those embedded efficiencies.

(ii) Nor does the fact that EGD has undertaken a process for reviewing a grass roots capital budget at the executive level provide much comfort as it does not provide any assurance that the initial grass roots capital budget itself was not greatly overstated. Aggressive line managers would normally build in a substantial "cushion" into their grass roots budget submission in anticipation of reductions being imposed by executives. Dr. Kaufmann also makes this point. He notes at p5 of his Assessment:

> "If the capital cost forecasts submitted at the outset of the budget process are inflated, the capital cost projection at the end of the process can also be inflated" (Ex L, T1, Sch 2, p5).

(iii) EGD states that the fact that it did not include what it describes as "variable costs", in its capital budget, is, in and by itself, a sustainable energy efficiency measure. However, this is not so as the costs in question are only "forecast" variable costs, and not very firm forecasts at that. For example, the company notes that:

> "at least some of the forecast variable costs will materialize" (Ex B2, T1, Sch 1, p28).

EGD has already included in its revenue requirement firm forecasts for 2014, 2015, and 2016, substantial capital expenditures for system integrity and reliability. It is hard to imagine that it would have the capability to do even more. In addition, EGD states that, in the first three years of the plan, it will conduct studies for the MOP and ILI programs (Ibid p28 and I.A1.1.EGDI.CCC.2). It also requested deferral account treatment for 2017 and 2018, for its system integrity and reliability expenditures.

(iv) Fourth, EGD's commitment to the company's EFT complement at its current level is not a compelling sustainable efficiency initiative for either the capitalized component thereof, which is part of the capital budget, or the component captured in the O&M budget. EFTs are a measure of complement or roles, not personnel. EGD admitted that there were currently 120 vacancies, and that on average, the vacancy rate (unfilled EFTs) amounts to about 5% (Tr. 7, pp 187-8). Thus, the company can hire 120 new permanent staff without exceeding the current EFT level. Moreover, the company has over 300 contract staff which do not encumber EFTs, but whose salaries are part of the relevant capital or operating budgets (Ibid p188).

(v) Finally, as noted by Dr. Kaufmann, the plan contains no third party, objective verification of the reasonableness of the proposed capital expenditures. An I-X style of IRM, either price cap or revenue cap, has objective industry wide criteria, both of inflation, and a productivity factor, and, often, a stretch factor, which constrain the company's ability to increase rates to cover overspending and incent the company to perform. Other IRM plans use benchmarking and/or detailed engineering studies to assess the reasonableness of the expenditures. Dr. Kaufmann noted that EGD's principal expert, James Coyne ("Coyne"), provided no benchmarking of the company's capital expenditure program. He stated that:

> "Neither EGD or CEA, EGD's principal advisor, has presented an external, objective standard directly addressing the reasonableness of the company's projected capital spending. Moreover, capital expenditures account for the lion's share of EGD's projected cost growth over the term of its IR plan, and the company has not put forward any external benchmarks that justify its projected capital spending" (Ex L, T1, Sch 2, p46).

(b) Operations Budget

Nor does the O&M plan contain details of alleged embedded sustainable energy efficiencies. There are no lists of such measures, the amounts of sustainable savings generated by each and the duration of the proposed savings. BOMA also believes that, as with the capital budget, EGD cannot use the budget review process as a guarantee that the O&M plan continues embedded sustainable energy efficiencies as alleged by EGD.

First, inflated initial submissions by managers can result in inflated final budgets.

Second, ratepayers assume that EGD always conducts a rigorous vetting process to arrive at its capital and operating budgets. The process used by EGD for this particular plan is only what one would expect. It cannot be claimed as a special event.

This is especially the case since the evidence demonstrates that, contrary to the claims by Coyne, EGD is not currently a "top performer" based on its combined capital and O&M unit cost per customer in 2010 and 2011, the most recent years for which data was presented (Ex TCU1.11X, pp 2 and 3)[2]. Tables 2 and 3 show that EGD's unit costs per customer (capital and operating combined) in 2011 and 2010 were $0.53 and $0.47, respectively. For 2011, EGD was the sixth worst performer among the 25 company peer group. For 2010, it was the twelfth worst performer; hardly a top performer.

Moreover, the companies that Coyne used as comparators for the twenty-five company industry group, and from which he selected the seven company "peer group" were not, in the main, representative of US utilities that are truly comparable to EGD, in term of growth rates and size, and other relevant criteria. Coyne instead employed "similar weather to EGD" as an initial, but determinative screen for both groups (Tr. 3. p167). Using only degree days as an initial screen meant that the comparator lists were dominated by older big city utilities, such as Detroit Edison (DTE M1), Con Edison, National Grid (New York City), Baltimore Gas & Electric, National Grid (Boston Gas), Public Service Gas & Electric (New Jersey), and the like, some of which continue to have large amounts of cast iron and uncoated steel pipe, which result in higher O&M capital costs.[3] EGD has replaced virtually all of its cast iron and uncoated steel pipe.

[2] Board staff provided this response, after Concentric was asked to provide a responsive undertaking, but did not.

[3] All but one of the five gas distribution companies with the largest percentage of mains installed before 1940 which were made from cast iron or uncoated steel (Consolidated Edison 43%) - National Grid (NY 40%), National Grid (Boston Gas) and Washington Gas, D.C. and two of the three distributors with the greatest number of gas leaks per one hundred miles of mains, Consolidated Edison (92) and National Grid (Boston) (69) are in Coyne's 25 company sample, NY Times, Monday, March 24, ppA1, A14, A15; citing data compiled by the Department of Transportation.

The use of weather as a determinative screen also left out some of the fastest growing US gas utilities, such as San Diego Gas & Electric (San Diego), Southern California Gas (Los Angeles basin), Pacific Gas & Electric (California Bay Area), Atlanta Gas Light, NSI (Phoenix area), Oneok in Oklahoma, and elsewhere, and Piedmont Gas, in the Carolinas. Compare Coyne's selection with EGD's statement in its 2013 Strategic Plan, that:

> "EGD currently serves over 2 million residential, commercial and industrial customers and remains one of the fastest growing natural gas distribution companies in North America" (J1.4).

Coyne's use of weather as an initial, determinative screen was his (Concentric's) own idea. He was unable to cite any other studies or research that supported using weather as the determinative screen for membership in a peer group used to "benchmark" the performance of natural gas utilities (Tr 1, p30, line 17).

So, even as compared with unrepresentative peer groups, improperly established by Mr. Coyne, so as to favour EGD, EGD did not fare well.

This conclusion is relevant to an assessment of the acceptability of EGD's plan because the company (and Coyne) have stated that since EGD is so efficient already, it will be difficult for it to find additional efficiencies or productivity enhancements (Ex A2, T1, Sch, par 69). Unfortunately, the premise is incorrect. EGD is not efficient relative to many of its peers.

Finally, the fact that EGD's "Other O&M" budget was held to an increase of approximately 2% per year is not in itself evidence of the claimed embedded sustainable efficiencies. Compared to Union's previous 2008-2012 plan and its current new plan, or the decline in rates under EGD's 2008-2012 I-X plan, these numbers are not exceptional.

The 2% inflation rate is higher than most recent forecasts of inflation for 2014 and 2015, including that of the Bank of Canada. The January 2014 Monetary Policy Report of the BOC forecast interest rates of 1.2% and 1.5% in 2014 and 2015. The most recent forecasts of the Federal Reserve contemplate similar rates for those years.

SEIM

BOMA is of the view that SEIM is not an appropriate incentive for sustainable efficiency improvements for several reasons.

First, and most important, the program puts the ratepayer at risk to pay for so-called productivity and efficiency initiatives that have not been shown to exist (our emphasis). They are only forecast to result from productivity or efficiency measures. At no point will EGD measure the dollar value of the improvements against an agreed baseline. The presumed benefits to ratepayers that are calculated as part of the NPV test, which is the hurdle EGD must meet before it can claim its reward, are simply forecasts of benefits. EGD will, in effect, rely on forecast benefits (set against actual costs), to determine whether the SEIM initiatives pass the NPV test, and will count these "phantom savings" for years into the future. This approach is not fair to ratepayers, and makes a mockery of the program. Wouldn't we all like to be able to use our forecasts of our future achievements to determine whether we qualify for a raise?

Second, with respect to EGD's alleged embedded savings, ratepayers must have specific evidence of the proposed initiatives and measured results. EGD did not submit any specific proposed SEIM measures in its evidence, with forecast savings arising from adopting those measures. Ratepayers are asked to approve an initiative without knowing any details about its content, in effect, to sign a blank cheque. This request is not acceptable.

Third, in contrast to EGD's Plan, under I-X based IRM plans, the incentives for efficiency are explicitly <u>built into</u> the rate making process. There is no need to have a separate program to incent the company to introduce savings measures. They are already incented by the inflation allowance, the X-factor, and the stretch factor. The contrast with EGD's proposal is striking. Rather than an IRM plan that is designed to incent efficiencies and productivity, EGD's plan is an IRM plan in name only, and ratepayers are asked to pay a second time through SEIM for efficiency measures that may not generate real savings.

Finally, the Board's Natural Gas Forum Report (the "Report") has stated the importance it attaches to documentation of any claimed productivity or efficiency measures <u>during the IRM period</u> and at rebasing (our emphasis). The Board stated:

> "With robust rebasing, all of the efficiency improvements achieved during the term of a plan would be built into the base rates for the subsequent plan. In this way, shareholders retain the benefits of any efficiency gains (that is, any achieved over and above the productivity factor) during the term of the initial plan, and all of the benefits flow to customers during the term of subsequent plans. <u>During rebasing, the Board will be particularly interested in determining whether the efficiency improvements achieved by the utility are temporary or sustainable, and it will expect to receive a through analysis of this issue</u>. For example, the Board will be interested in the relationship between operation, maintenance and administration costs and capital expenditures, the timing of capital expenditures and the associated impacts on shareholders and customers. <u>The Board will also expect to see, during the plan's term, measures that are designed to improve the</u>

> utility's productivity on a sustained basis - not temporary, unsustainable budget cuts. The Board's determination of the new base rates and forward plan will reflect its assessment of all of these factors. The Board also cautions that it will take an unfavourable view of sudden and significant increases in costs at the time of rebasing, unless thoroughly justified". [Report, p26]

In order to conduct the rebasing exercise described above, the Board must have quantitative data on the energy efficiency initiatives over the term of the plan. They will not get this data in EGD's plan.

In other words, the Board expects sustainable efficiency measures, as an integral part of IRM, not as a response to a separate incentive. The SEIM program is not consistent with those principles.

3. *Does Enbridge's Customized IR plan ensure appropriate quality of service for customers?*

EGD's plan pays relatively little attention to demonstrating how it will improve its customer service performance.

Dr. Kaufmann noted in his study for the Board of the EGD and Union five year IRM plans for the period 2008-2012, that EGD's customer service deteriorated during the term of the plan, while Union's performance held steady (see below at p35).

4. *Does Enbridge's IR plan create an environment that is conducive to investment, to the benefit of customers and shareholders?*

The EGD Plan does not create an environment that is conducive to investment to the benefit of customers, and the substantial increase in revenue it provides to the company is unnecessary to maintain its financial viability.

As discussed at A1 above, the EGD Plan creates an incentive for EGD to over-forecast and underinvest, because it can increase its annual earnings by so doing. And, as Dr. Kaufmann has noted, contrary to EGD's assertion, the presence of an earnings sharing mechanism does not negate this conclusion; first, because of the 100 basis points deadband, and second, because the ratepayers receive only one-half (50%) of any increased earnings beyond the deadband.

Second, EGD has not demonstrated that without the plan's very large increase in revenues over the five year period, it would suffer either short term liquidity or long term capital adequacy problems.

In Management's Discussion and Analysis in connection with its December 31, 2013 Financial Statements (Ex J1.1, Attachment 2), in its discussion of Liquidity and Capital Resources, it advised that its long term debt interest coverage ratio, at December 31, 2013, was a healthy 2.40, up from 2.04 in 2012.

The company also states that:

> "The net planned liquidity, together with cash from operations and anticipated future access to capital markets, is expected to be sufficient to finance all currently approved capital projects and to provide flexibility for new investment opportunities." (Ibid, Management Discussion and Analysis, 2013)

Moreover, EGD has not demonstrated that failing to obtain approval of the plan would mean that it would be in breach of its debenture covenants, or line of credit-related conditions or commitments. EGD has a capital expenditure budget spike in 2014 and 2015, caused by the GTA project, but has not shown a need for increased funds in 2016 and beyond on the scale proposed in its plan. In fact, capital expenditures are forecast in 2016 to return to pre-2014 levels, or below.

Moreover, Union, in its recently concluded Settlement Agreement, approved by the Board, funded its comparable (in relative terms) capital expenditure on Parkway West and Dawn-Parkway reinforcement within the context of an I-X version of an IRM plan, with Y-factor treatment for those specific expenditures, but without the large, across the Board, increases in revenues proposed by EGD.

Finally, EGD has overearned each year since 2000, and in almost every year in the last 25 years, even after earnings sharing where such existed (Ex I.AI.EGDI.STAFF.4); and after the correction of its error in calculating earnings, for some of the IRM years (J1.3).

5. *Is the methodology within Enbridge's Customized IR plan for determining annual Allowed Revenue amounts appropriate?*

BOMA does not view EGD's proposed methodology to determine its Annual Allowed Revenue Requirement to be appropriate because it represents a cost of service approach for calculating the Allowed Revenue for each year, starting with 2014, the first year of this plan. In its prefiled evidence, under the title "Components of the IR Plan/Allowed Revenue Requirements for 2014 to 2018", EGD states that the Allowed Revenue is:

> "To be determined by summing together, for each year, the appropriate level of operating costs, depreciation costs, taxes, and cost of capital. These annual amounts are what EGD will be entitled to collect in rates each year" (Ex A2, T1, Sch 1, p3 of 40).

This sentence, insofar as it relates to the year 2014, is an accurate description of a cost of service submission. The utility proposes to collect its cost of service and return. The

2014 Allowed Revenue is no different than what the 2014 Revenue Requirement (which is the phrase the Board uses in the RRFE to describe this amount) would be if 2014 were the test year in a one year cost of service plan.

Taking 2014 as an example, there is no difference between EGD's approach and a one year cost of service plan. Like in a cost of service application, an overforecast (actuals lower than forecast) would result in a higher than allowed earnings for the company, while an underforecast (ie. actuals higher than forecast) would mean the company is at risk for the excess. But, unlike EGD's Plan, under an annual cost of service plan, the Board would be able to correct for the 2014 overforecasting in 2015, and "reimburse" the ratepayers, rather than have the ratepayers exposed for several years.

EGD's forecast of return on equity and debt costs (the two together constituting the cost of capital) for the five year plan is particularly troublesome for BOMA. Rather than having the base year ROE of 8.93% apply for each year of the plan, which has been the norm for recent IRM plans, EGD forecasts ROEs of 9.27% in 2014, 9.72% in 2015, 10.12% in 2016, 10.17% in 2017, and 10.27% in 2018.

EGD has forecasted an increase in the return on equity in each year of the five year plan, based on the Board's reset of the equity premium amount and the process for the annual adjustment of the ROE set out in EB-2009-0034. The company used the 9.75% ROE, which the Board established as a "reset" ROE in that 2009 generic proceeding as the starting point, and then adjusted it using the Board's revised adjustment guidelines also established in that proceeding. However, the Board noted in its subsequent annual adjustment documents setting out the required adjustments to that rate since 2009, that the 9.75% ROE was set in the recognition that it was to be adjusted annually by the guideline in cost of service cases for years subsequent to 2009 (our emphasis). (Board Letter and Web Posting, November 25, 2013, Cost of Capital Parameter Updates for 2014 Cost of Service Applications). The fact that EGD has used both the starting rate, and the annual adjustment mechanism from EB-2009-0034 underlines the cost of service nature of its so-called IRM. The formula was not used to establish the rate in the rebasing year (our emphasis). The 9.75% is an inappropriate starting point, whatever the rationale EGD uses to increase the rates.

BOMA believes that the return on equity should be held at 8.93%, the rate established in the rebasing year, during the IRM term. That was the practice in EGD's last IRM (2008-2012) and in Union's two recent IRMs (2008-2012 and 2014-2018).

There is no justification to establish the 2014 ROE using the 9.75% as the starting point, whatever the Board decides on the other cost components of the plan.

The difference in forecast Allowed Revenue, or revenue requirement, relative to retaining the 8.93% rate from the rebasing year over five years, is $130 million, which is a large additional levy on ratepayers (Tr V. 10, p19). EGD argued, in its attempt to justify this approach, that unlike in an I-X IRM, in which the inflation forecast is supposed to compensate for the risk of interest rate changes, there is no explicit forecast of inflation, only a forecast of costs that contribute to the "Allowed Revenue Requirement", and the absence of such an inflation factor would support forecasting increases to the ROE in each year (Ex A2, T5, Sch 1, p3, par 10). However, EGD has used an implicit inflation rate of 2% in both its capital and O&M annual budgets (D1, T3, Sch 1, p10). The fact that it is not separately identified does not change the fact that if it already included in both capital costs and operating costs, forecasting an increase in ROE based on the alleged absence of an inflation factor would be wrong. It would be double counting. Moreover, the percentage increases in the ROE from 2013 to 2014, from 2014 to 2015, and from 2015 to 2016, are approximately 3.3%, 5%, and 4.1%, respectively; much higher than the embedded 2% inflation rate. Finally, EGD said it would not use the Board's annual adjustment guideline each year as contemplated by the Board, but rather made a five year forecast at the outset. But it did not provide a substantive reason for its decision.

6. *Is the methodology within Enbridge's Customized IR plan for updating the 2017 and 2018 Annual Revenue amounts within the 2016 Rate Adjustment proceeding appropriate?*

In EGD's December 2013 amendment to its plan, it stated there would be no updating of the 2017 and 2018 Annual Revenue Adjustments. EGD has forecast capital budget and O&M budgets for 2017 and 2018 but these forecasts have assumed that the identical 2016 capital amounts in 2017 and 2018, a highly unlikely event. The 2017 and 2018 numbers are at the very best "ballpark" estimates. EGD has agreed that it does not know the amounts for at least some important components of its capital and operating budgets for 2017 and 2018 (Tr 4. p199) for those years as illustrated by the following exchange between Mr. Brett and Mr. Sanders;

> "Mr. Brett. Right, you have said… you have just told me why you have (assumed that 2017 and 2018 capital costs would be the same at 2016 capital costs) is that you really don't know what the costs are going to be in those last two years. Mr. Sanders. In a number of critical areas, that's correct."

This absence of hard information underlines the inappropriateness of a five year Allowed Revenue (Revenue Requirement) Plan which depends on five year forecasts of costs. It is no more appropriate than a five year cost of service proposal. The Board refused to review a proposed three year cost of service plan, proposed by Toronto Hydro in 2012.

7. *Is the methodology within Enbridge's Customized IR plan for determining final rates for 2014 appropriate?*

In BOMA's view, EGD's Plan for determining final 2014 rates is inappropriate.

First, as described in A1 and A4 above, EGD has used an inappropriate rate of return on equity to calculate the return component for EGD's 2014 "Allowed Revenue" (Revenue Requirement).

Second, it has calculated 2014 rates on the basis of forecast rate base, and depreciation, and no provision for a true-up (with the exception of the GTA project) in the event that assets placed in service in 2014 are less than forecast.

Third, EGD's forecasts for debt issuance in 2014 and 2015 which forecast the cost of ten year medium term notes to increase from 3.8% in 2014 to 4.3% in June 2015, to 5.0% in October 2015 are likely too high. This seems a relatively rapid escalation in interest rates given the current stance of the Bank of Canada and the Federal Reserve. Of course, no one knows now what the interest rates will be in 2015, let alone in the out years. That is one reason the Board directed parties to make annual forecasts of government and corporate bond interest rates in determining the annual adjustments to the allowed ROE.

As noted above, the method EGD used to establish 2014 rates would be more appropriate for a one year cost of service plan than a five year IRM plan.

8. *Is the methodology within Enbridge's Customized IR plan for setting final rates for 2015 through 2018 through annual Rate Adjustment proceedings, including cost allocation and rate design, appropriate?*

<u>Annual Rate Adjustment Proceedings</u>

BOMA understands that EGD proposes to hold an Annual Rate Adjustment Proceeding ("Annual Proceeding") to set final rates for 2015, 2016, 2017, and 2018.

In each annual proceeding, the rates for the preceding year would be increased to reflect the increased forecast Allowed Revenues (Revenue Requirement) for cost of service, taxes, and returns as forecast in the plan, with adjustments for average number of unlocks, volumes and gas costs related impacts, and amounts related to pension, DSM and Customer Care costs. After the end of each year, in the ESM review, Deferral and Variance Accounts and any potential Z-factor items would be reviewed and disposed of by the Board, and earnings sharing would be finalized.

There would be no annual true-up for overforecasting.

In this annual proceeding, or as part of the annual ESM proceeding, EGD would report on the productivity enhancements and efficiency measures that it launched in the previous year, including the projects that it believed qualified for SEIM treatment. It would answer questions on the proposals but the proposals themselves or their forecast savings would not be subject to Board approval. There is also a lack of clarity as to what information would be filed in these annual proceedings. (Tr 7. p174). Board approval or otherwise of the projects and the forecast savings would apparently not be addressed until rebasing. The process is not appropriate because it does not provide for intervenors or Board scrutiny necessary to realize the Board's objectives. The Board's scrutiny of the evolution and growth of productivity enhancement and sustainable efficiency initiatives, needs to take place on an annual basis in order for the Board to:

- see clearly the progress of, and the nature of, each initiative;
- examine and understand how the forecast savings are being realized and measured;
- see data that is recent, where results can begin to be seen in near "real time", not five years later;
- be able to focus on productivity enhancements and sustainable efficiencies as important matters in themselves, and not be treated as only one issue in an extremely complicated rebasing process, where the issue will tend to be obscured by the utility's new resource demands and other more "urgent" matters.

It is not clear whether there would be two or three annual proceedings. There is the ESM proceeding, the annual rate adjustment proceeding, and possibly the proceeding where the productivity and efficiency initiatives are identified, described, and reported upon.

Finally, the annual rate adjustment proceedings have the same flaws as the process proposed to set 2014 rates, discussed above. In each case, forecasts of all major costs components are used, with no protection for ratepayers for overforecasting. These annual rate adjustment proceedings are very similar to what one would have in a series of one year cost of service plans, since the adjustments are driven almost entirely by forecast costs and revenues (unlocks, gas volumes) in the next (test) year. Like a cost of service plan, a series of pass through adjustments would be made, including gas, pension, CIS, and DSM.

9. Are the cost of capital parameters for 2014 to 2018 (ROE, debt rates) within Enbridge's Customized IR plan appropriate?

This topic has been discussed at some length above.

To reprise, return on equity should be maintained at the level set in the rebasing year as has been the case with the three most recent gas IRM plans. EGD's view of the cost of capital as "just one more cost" to be recovered in rates (Tr V10, p22), reflects a cost of service model, not an IRM model. EGD's five year ROE forecast is simply a risk-reducing variation of the annual adjustment process contemplated by the RP-2009-0034 for cost of service cases. In a true ICM program, where increases are governed by industry-wide inflation, and productivity, and (perhaps) individual stretch factors, EGD's return is determined by the productivity enhancements and sustainable efficiencies achieved over the term of the plan.

10. Are the following components within Enbridge's Customized IR plan appropriate?

a. Z Factor mechanism

EGD's proposed Z-factor is not appropriate. BOMA suggests the Z-factor criteria found in the 2008-2012 EGD Plan be maintained subject to the modest changes suggested below.

In that IRM (Settlement Agreement) (EB-2007-0615, T1, Sch 1, p21), approved on February 4, 2008, the parties agreed that Z-factors generally have to meet the following criteria:

> "(i) the event must be causally related to an increase/decrease in cost;
>
> (ii) the cost must be beyond the control of the Company's management and is not a risk in respect of which a prudent utility would take risk mitigation steps;
>
> (iii) the cost increase/decrease must not otherwise be reflected in the per customer revenue cap;
>
> (iv) any cost increase must be prudently incurred; and
>
> (v) the cost increase/decrease must meet the materiality threshold of $1.5 million annually per Z factor event (i.e., the sum of all individual items underlying the Z factor event)."

In its Report on Third Generation Incentive Regulation for Ontario's Electricity Distributors, at Appendix IV ("2008 Report"), which appeared soon after the EB-2007-0615 decision, the Board endorsed the criteria stated in EB-2007-0615, including the direct causal link between the Z-factor event and the increase or decrease in cost, the use of the materiality and prudency qualifiers, and the requirement that the Z-factor events are events that are not within management's control.

In its October 18, 2012 Report on the Renewed Regulatory Framework for Electricity Distributors, the Board again endorsed its position on Z-factors in its 2008 Report (see Table 1, p14).

Finally, the recent Union IRM case (EB-2013-0202) was implemented through a Board approved Settlement Agreement, set out very similar criteria to those adopted in EB-2007-0615.

Section 8 of that recent Union Agreement stated:

"The parties agree that for prospective or historical cost increases/decreases to qualify for pass through as a "Z factors", the cost increases/decreases must:

1. causally relate to an external <u>event</u> that is beyond the control of utility's management (our emphasis);

2. result from, or relate to, a type of risk;

   a. for which a prudent utility would not be expected to take risk mitigation steps; and,

   b. which is out of the realm of the basic undertaking of the utility (per EB-2011-0277 Decision, page 13);

   3. not otherwise be reflected in the price cap index;

   4. be prudently incurred; and,

   5. meet the materiality threshold of $4.0 million of annual net delivery revenue requirement impact per Z factor event. Net delivery revenue requirement will be defined in the same manner as set forth in Section 6.6 above.

The parties agree that changes in the amounts of taxes payable by Union through the 2014-2018 IRM term resulting from changes to Federal and/or Provincial legislation and/or regulations thereunder are Z factors and will be shared 50:50, as applied to the tax level reflected in rates. Treating 50% of tax changes as a Z factor is consistent with the Board's findings in its EB-2007-0606/EB-2007-0615 Decision (dated July 31, 2008)".

The terms of the Z-factor set out in the Union case are very similar to those of EGD's previous IRM.

- Like EGD, criteria one links the increased or decreased costs to an <u>event</u> (our emphasis).

- Like EGD, the event that triggers the cost must be beyond the control of management (EGD states the cost must be beyond the control of management but, since the cost flows from the event, the end result is the same).
- Like EGD, it states that the cost is not (the realization of):
    - a type of risk in respect of which a prudent utility would take risk mitigation steps,
- Like EGD, it stated that the costs must be prudently incurred, and not be otherwise reflected in the price cap (or per customer revenue) cap;
- Like EGD, it states that the cost increase or decrease must meet a materiality threshold, but a higher one - the threshold is $4.0 million of annual net delivery revenue requirement (as defined in the Agreement) per Z-factor event.

In this case, EGD proposes major changes to the principles that the Board has followed for a considerable period of time in both the gas and electric cases, on the grounds that the changes would make the criteria more clear and consistent (A2, T4, Sch 1, p2 of 9).

EGD's first major proposed change is replacing the idea that an external event must drive the cost increase or decrease, with the idea that the cost increase or decrease must be due to an unexpected, non-routine cause. The proposal would be a retrograde step since it would substitute for an "event" as the driver of a Z-factor eligible cost, a non-routine, unexpected "cause".

In our opinion, the EB-2008-2012 Z-factor language that an "event must be causally related to an increase/decrease event" is far clearer than EGD's proposal that "the cost increase or decrease, or a significant portion of it must be demonstrably linked to an unexpected non-routine cause".

As Dr. Kaufmann noted:

> "'Events' are discrete, concrete, and readily identifiable. 'Causes' are often subtle, complex and difficult to identify. Changing the impetus for Z-factor filings from 'events' to 'unexpected, non-routine causes' would shift the focus of Z-factor investigation into broader and murkier territory. This, in turn, is likely to lead to more frequent, contentious, and costly Z-factor proceedings" (Ex L, T1, Sch 2, p24).

BOMA agrees with Dr. Kaufmann's assessment. Also, we agree with Dr. Kaufmann's comment that, given the nature of the Company's revenue requirement driven, cost based plan, EGD could utilize the "unexpected, non-routine cause" language to file a Z-factor application wherever a cause arises that it did not anticipate when preparing its plan.

The addition of the phrase "or a significant part of it" causes further uncertainty. What is "significant" will be a source of endless argument.

EGD's second proposed change, that "the cost increase be beyond the control of the utility" be changed to "not be reasonably within the control of utility management" would introduce more confusion, as parties would argue at length about what is "reasonable". A better wording would be "the event that drives the cost is beyond the control of utility management, and the event is not the realization of a risk in respect of which a prudent utility would take risk mitigation steps".

When stated this way, the risk mitigation concept becomes clearer and should not cause confusion.

Whatever else the Board does with EGD's application, the Board should not approve EGD's Z-factor proposal. Among other things, it is incompatible with the Board's statement of principle in the RP-2004-0213, p31; the Natural Gas Forum Report, that Z-factors be applied in "limited, well-defined, and well-justified uses only" and would shift more risk onto ratepayers.

b. Off-ramp condition

BOMA supports EGD's off-ramp proposal, which would also be applicable under an I-X IRM plan.

c. Earnings Sharing Mechanism

BOMA supports the Earnings Sharing Mechanism, which would also be appropriate in an I-X plan, and is identical to the ESM agreed in the EGD 2008-2012 plan.

d. Treatment of Cost of Capital

See above.

e. Performance Measurement mechanisms, including Service Quality Requirements (SQRs)

See above.

f. Sustainable Efficiency Incentive Mechanism

See above.

g. *Annual reporting requirements*

See above.

h. *Rebasing proposal*

See above.

i. *Treatment of pension expense and employee future benefits costs*

The parties agreed to a formulaic treatment of pension and OPEB costs in the EB-2011-0354 rebasing year Settlement Agreement, which should be maintained, and that the Transition Impact of Accounting Charges Deferral Account (TIACDA) should continue to operate in the manner set out at clause 4 on p24 of that Settlement Agreement.

j. *Treatment of DSM costs*

The parties have agreed that DSM is the subject of a separate proceeding.

k. *Treatment of Customer Care and CIS costs*

The parties agreed in the EB-2011-0226 Settlement Agreement to a formulaic annual adjustment to the CIS costs and separate rate regulatory accounting treatment for those costs for the period 2013 to 2018. BOMA agrees with the continued implementation of that Agreement.

33. *With respect to any alternative IR plan proposed for Enbridge, does that proposal meet the Board's objectives for incentive regulation for gas distributors and is it appropriate?*

34. *With respect to each of the components of any alternative IR proposal, are those components appropriate?*

35. *What are the regulatory alternatives to the Board approving the Enbridge rate proposal? Are any alternatives to approving the rate proposal appropriate?*

The Board has the responsibility to set just and reasonable rates for the sale and distribution of natural gas. In doing so, it is free to choose the methods and calculations for the rates it approves, be they of cost of service, incentive rates, or hybrids. The Board can also specify a particular type of incentive regulation. These principles are set out in the sections of the Ontario Energy Board Act (the "Act"), discussed below.

Section 36(1) of the Act provides that:

> "No gas transmitter, gas distributor or storage company shall sell gas or charge for the transmission, distribution or storage of gas except in accordance with an order of the Board, which is not bound by the terms of any contract. 1998, c. 15, Sched. B, s. 36 (1)."

Section 36(2) of the Act provides that:

> "The Board may 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. 1998, c. 15, Sched. B, s. 36 (2)."

The rate-making powers of the Board are very broad. Section 36(3) states that:

> "In approving or fixing just and reasonable rates, the Board may adopt any method or technique that it considers appropriate. 1998, c. 15, Sched. B, s. 36 (3)."

Section 36(4) provides 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. 1998, c. 15, Sched. B, s. 36 (4)."

In a rate proceeding, the Board may fix rates other than those applied for by the utility.

Section 36(5) states that:

> "Upon an application for an order approving or fixing rates, the Board may, if it is not satisfied that the rates applied for are just and reasonable, fix such other rates as it finds to be just and reasonable. 1998, c. 15, Sched. B, s. 36 (5)."

Finally, the Board can, on its own motion, initiate a proceeding to fix rates.

Section 36(7) states that:

> "If the Board of its own motion, or upon the request of the Minister, commences a proceeding to determine whether any of the rates for the sale, transmission, distribution or storage of gas by any gas transmitter, gas distributor or storage company are just and reasonable, the Board shall make an order under subsection (2) and the burden of establishing that the rates are just and reasonable is on the gas transmitter, gas distributor or storage company, as the case may be. 1998, c. 15, Sched. B, s. 36 (7)."

In the Natural Gas Forum Report (the "Report"), the Board expressed a preference for IRM rate plans over cost of service based rate plans and for an IRM term of between three and five years. The Board also made it clear that comprehensive IRM plans, which dealt with capital and O&M expenditures in an integrated fashion were preferable to targeted plans, such as EGD's first generation IR plan (1999) which was targeted to O&M costs only, and in which capital costs were dealt with on a cost of service basis. The Board also noted the widespread disappointment with that plan. To BOMA's knowledge, the Board has made no further general pronouncements on gas IRM plans.

Subsequently, both Union's and EGD's 2008-2012 IRM plans were the subject of Settlement Agreements, as was Union's 2014-2018 IRM. All three were the I-X type of IRM plans. Dr. Kaufmann analyzed EGD's and Union's 2008-2012 plans for the Board, and found them successful (Ex L, T1); Assessment of Union Gas Ltd. and Enbridge Gas Distribution Inc. Incentive Regulation Plan, Revised April 12, 2012, Pacific Economics Group Research (PEG). In that Report, Dr. Kaufmann, PEG-R's assessment focused on the Board's key criteria for an effective ratemaking framework, particularly the following issues:

- "Did the incentive regulation plans encourage cost control and generate productivity and efficiency improvements?
- Did both customers and shareholders share in the benefits of any efficiency gains that were achieved?
- Did the Companies provide appropriate service quality to their customers?
- Was the incentive regulation framework conducive to capital investment?" (Ex L, T1, p3)

On the first criteria, PEG concluded as follows:

> "The IR plan satisfied the Board's criteria of encouraging cost control and productivity improvements. Our analysis indicates that the IR plans encouraged both EGD and Union to control costs more effectively and generate productivity and efficiency improvements" (Ibid, p.vi).

On the second criteria, whether ratepayers shared in the benefits of any efficiency gain that were achieved through gas delivery prices lower than they would otherwise have been. PEG concluded that:

> "Overall, however, PEG-R's gas delivery price indexes show a modest 0.4% annual increase in gas delivery prices for Union's M1, M2, Rate 01, and Rate 10

> customers, and an annual 0.32% decline in EGD's gas delivery prices over the terms of the IR plans" (Ibid, p.ii).

On the third criteria, maintenance of appropriate service quality, PEG concluded that, over the measured term of the plan:

> "Union is consistently satisfying the standards that the Board has established for appropriate service quality performance while EGD is not".

On the fourth criteria, the maintenance of a framework conducive to capital investment, PEG concluded as follows:

> "There is little doubt that both Companies have enjoyed healthy returns under IR. Earnings are well above the levels that the Companies generated prior to the implementation of the plans and also above the levels at which earnings are shared with customers. This is particularly true for Union. The relative level and burden of long-term debt has also declined, and other financial ratios have improved. Overall, the financial indicators for both EGD and Union support the conclusion that the IR plans have created an environment that is conducive to attracting capital and funding capital investment".

Other Canadian regulators have agreed with the Board on the merits of the I-X approach to IRM, for example, Alberta.

BOMA concludes from the above that the Board's experience with comprehensive I-X IRM plans in the gas industry has been successful, while EGD's targeted IRM program was not. EGD's proposed plan shares some features of its first, O&M only, targeted plan, in that it treats O&M costs and capital costs in different ways. For example, O&M costs are benchmarked while capital costs, or total costs are not. EGD must demonstrate that its version of a custom IR plan is superior to an I-X IRM plan. In BOMA's view, it has not done so.

Further, to that point, EGD states that its current IRM proposal is very similar to its 2nd IRM proposal, for the years 2008 to 2012. It is clearly not, for many reasons:

- there is no independent industry derived standard for inflation and productivity costs, against which EGD's performance can be measured and which provides a substantial incentive for EGD to develop productivity enhancements and sustainable efficiencies. EGD's previous plan allowed rates to increase each year in an amount equal to declining percentage of measured GDP, IPI inflation, namely, 60% in 2008, 55%, 50% in 2009, and 2010, 50% in 2011, and 45% in 2012, respectively. The X-factor in those coefficients (inflation minus the coefficient percentage) increased over the five years of the plan. The use of the inflation coefficient avoided having to forecast inflation rates up to five years out.

- the second IRM Z-factor was clearer and narrower than EGD's proposed formulation (see above for details).

- EGD's current proposed plan contains a sustainable efficiency incentive as an add-on. In the earlier plan, the incentive for productivity enhancement and sustainable efficiencies was built into the basic structure of the plan.

- the previous plan had no deferral or variance accounts around major capital expenditures.

Regulatory Alternatives

The Board has several alternatives if it were to find that EGD's Plan would not result in just and reasonable rates. It could, for example, approve 2014 rates only, on a cost of service basis, using the evidence that has been filed in the case. As noted above, the material EGD has filed for 2014 rates is the material it would have filed in a cost of service proceeding to set 2014 rates, with very few adjustments, and those adjustments are "fixable". The Board would also direct EGD to prepare an I-X form of IRM proposal for the five year period commencing January 1, 2015. The I-X IRM proposal with or without a capital module (to accommodate the GTA project) would deal with many of the serious weaknesses intervenors and Board Staff have identified in EGD's current proposal. Given the data that EGD has already assembled and the work completed by Coyne, it should be possible for EGD to file a revised IRM plan by August or September, for implementation by January 1, 2015.

That option would allow EGD the capital they need to commence construction on the GTA, but offer the ratepayers protection from overforecasting for 2014, because another IRM plan which commenced on January 1, 2015 could take any shortfall in 2014 rate base into account.

Second, an I-X type of IRM would incorporate an objective, independent check on the reasonableness of capital and O&M expenditures, incent productivity and efficiency initiatives in a sensible way, remove the need to forecast detailed capital and O&M budgets five years into the future, remove the incentive to overforecast, and make the SEIM type of incentive unnecessary. An I-X plan would meet the Board's objectives for incentive regulation much more than that EGD's current proposal.

Another alternative would be for the Board to approve a two year cost of service plan to cover the years 2014 and 2015, or two successive one year cost of service plans for 2014 and 2015 and a direction to EGD to file a five year IRM commencing January 1, 2016 (BOMA prefers the one year cost of service interlude as it allows EGD to return to IRM plan more quickly). Either of these options would allow EGD the capital it requires to complete construction of the GTA project, which is what has caused the spike in capital costs rate base, and some of the increase in depreciation in those years, without the harmful side effects for ratepayers of the proposed five year revenue requirement plan.

These harmful side effects are due in part to the fact that EGD has not been able to forecast capital or O&M costs beyond 2016, but has perceived that it is "required" to do so, to meet the five year term that it believes it needs to get its plan approval. The irony here is that the type of plan it has selected requires it to forecast the details of capital, O&M, and other costs for five years, which is not really possible for EGD. Conventional cost of service rate cases also make forecasts, but only for the test year, or at most for two test years, which is more doable. EGD's choice of plan with its heavy reliance on "allowed revenue", in reality Allowed Revenue Requirement, is inconsistent with the idea of an extended term. The risk of such an approach is particularly acute for ratepayers, given that the problem the plan needs to address is a two-year spike in capital costs followed by a return, commencing in 2016, to the more traditional growth pattern of capital, and because of EGD's proposal to use deferral accounts for its more strategic expenditures in 2017 and 2018.

EGD has not presented persuasive evidence in this case of a bump of growth in 2016 and afterward, from expenditures in 2013, 2012 and 2011, nor has it proposed any reduction in other capital costs (so-called core capital) to offset the GTA project requirement, and/or increased integrity and reliability expenditures.

Alternative Plans

As the Board is well aware, it is the applicant's job to present and defend its plan, and in so doing, the applicant cannot use the argument that the Board must accept its plan because no party has submitted a better plan. If the Board finds the applicant's plan would not result in just and reasonable rates, it must reject it. It cannot, and should not, use, as part of its assessment, the fact that no intervenor has presented a better alternative. That is not the intervenor's job. The intervenor does not have the necessary information; it is not the owner of the business.

To do otherwise would mean the Board would produce the anomaly of the intervenors and the applicant presenting dueling IRM plans, which is not consistent with the Act. The Act contemplates that the utility submits the rates application and defends it.

This conclusion is also consistent with the Board's analysis during the initial part of this proceeding. In Procedural Order No. 2, in this case, "Decision on need for a hearing on a Preliminary Issue", issued on October 3, 2013, the Board determined not to hold a hearing to determine a preliminary issue.

The Board stated, at p3:

> "The Board has considered the parties' submissions and finds that the most efficient course is to proceed immediately with the entire application. In the Board's view, the preliminary issue is sufficiently broad and the process not sufficiently defined to be conducive to improving the overall hearing efficiency. In making this determination, the Board is also of the view that it is not obligated to either approve or deny the framework as proposed by EGD. The Board has not heard any compelling case that it would be restricted from establishing an alternative framework, were it to find that it would be appropriate to do so, and provided that there was an evidentiary basis for it" (our emphasis).

The Board certainly has the evidentiary basis to approve a one year cost of service framework. It probably also has the framework to establish an I-X plan with a capital module to deal with the GTA project.

Why not an I-X plan

EGD has stated that an I-X plan would not yield the revenue it needs to run its business over the next five years. However, it has not provided substantive evidence to support the revenue requirement. For example,

- nowhere does it provide a third party validation or benchmarking of its capital requirements over the next five years; Coyne's benchmarking of O&M costs is against an inappropriate peer group;

- it is a high cost utility, relative to its peers, even peers selected by methods designed to produce a bias in its favour, when the most recent capital and operating costs are compared on a combined basis, as they must be for a fair comparison;

- the annual Allowed Revenue (Revenue Requirement), which underpins rates under the plan, includes constantly increasing ROEs as a result of using an artificially high base rate of 9.75% and making adjustments based on forecast debt costs for a five year period;

- Coyne's analysis (Ex A2, T9, Sch 1) rules out I-X proposal on the grounds that if the inflation and X-factor that would need to be used, to raise the EGD revenue, but, as noted above, he does not analyze the reasonableness of the capital costs. He claims, contrary to best practices, that capital costs are too particular to each utility to permit benchmarking. Moreover, he deals with operating costs differently. He purports to show, that EGD O&M cost growth is less than an I-X equivalent, and benchmarks operating costs against an inappropriate peer group. As Dr. Kaufmann noted, Coyne uses EGD's revenue requirement to benchmark various I-X adjustment formulae, rather than the other way around (Ex L, T1, Sch 2, p6);

- the additional capital requirement that EGD alleges will be necessary in the future because of existing and planned regulatory and legislative changes is not clearly explained in sufficient detail, documented, or benchmarked, against other utilities, in particular, Union Gas;

- Coyne's repeated assertions that EGD is a "top performer" and will be hard pressed to find additional savings is not supported by the evidence; in fact, the evidence shows the opposite.

To summarize, BOMA urges the Board not to approve the EGD Plan as filed. The Board should approve a one year cost of service plan based on the information EGD has filed in this case, and direct EGD to file by September 1, for January 1, 2015, implementation a five year IRM plan of the I-X type. Given the fact that Union and its ratepayers recently settled a five year IRM plan of the I-X type, which was approved by the Board, BOMA sees no reason why the Board should not require EGD to file an I-X plan. Both Union and EGD have made planned substantial capital expenditures in the 2014, 2015 years, not all of which are immediately revenue generating. The expenditures are of similar magnitude relative to the assets and cash flows of the two firms. Both firms are subject to the same Ontario regulatory requirements concerning pipeline integrity and reliability.

Moreover, EGD has a more attractive franchise than Union, much less dispersed, no far north component, and a more stable customer mix, notably large, commercial, institutional, and residential components with much less heavy industry exposed to the international economy than Union. EGD has the advantage of a franchise concentrated in the relatively affluent and growing regions of Greater Toronto and Greater Ottawa, the two largest, most affluent, and fastest growing urban areas in the province. If Union can operate within an I-X framework, EGD should be able to do so.

11. Is the proposal to continue Enbridge's current deferral and variance accounts through the IR term appropriate?

Existing Deferral Accounts - BOMA agrees with the continuation of Union's existing deferral and variance accounts.

12. Is the proposal for the creation of the following new deferral and variance accounts appropriate?

a. Greater Toronto Area Project Variance Account ("GTAPVA")

EGD is of the view that the Board should approve an asymmetric variance account for the GTA project, which will operate only in the event that EGD underspends in any year relative to forecast. EGD has argued that the principal difference between its IRM plan and a cost of service plan, is that EGD must live within forecast capital and O&M budgets. Allowing EGD to recover overages on its GTA budget is inconsistent with EGD's fundamental argument for its plan, and how it differentiates its plan from a five year cost of service plan, and would be inappropriate. In the event that EGD were to submit an I-X type of plan, BOMA would support a symmetrical variance account, subject to a prudency review on any overage.

BOMA is of the view that only assets that are used and useful can be included in rate base and, therefore, generate depreciation expenditures and earn a return and assumes that EGD has forecast rate base, depreciation, and returns, on that basis, and its position here is conditioned by that assumption. This approach is also consistent with the approach taken by the Board in the two recent Toronto Hydro cases. See, for example, EB-2012-0064, Phase 2, Settlement Agreement, Section 5.

Any deferral account credit to ratepayers, should be cleared in the ESM proceeding immediately following the year in which the underspend occurs. Clearance in this manner will protect ratepayers against EGD's overforecasting on the project, which is a substantial risk for ratepayers inherent in the plan.

b. Constant Dollar Net Salvage Adjustment Deferral Account ("CDNSADA")

BOMA approves the creation of the 2014-18 Constant Dollar Net Salvage Adjustment Deferral Account.

c. Customer Care Services Procurement Deferral Account ("CCSPDA")

BOMA adopts the argument of Energy Probe on this issue.

d. Greenhouse Gas Emission Impact Deferral account ("GGEIDA")

BOMA supports this account.

<u>New Deferral Accounts</u>

The updated evidence filed on 2014-3-24 provided a description of a new deferral account, the 2015-2018 Greater Toronto Area Incremental Transmission Capital Revenue Requirement Deferral Account (D1, T8, Sch 7, p1).

At paragraph 2, EGD suggests that this account will only be required in the event that, at the time Segment A is put into service, there are no transportation customers. BOMA suggests that the account is required in the event that there is not a reasonable number of contracted shippers at the time the Segment A is put into service to cover the transmission portion (60%) of the revenue requirement including the cost of the upsizing. EGD's distribution customers should not be asked to subsidize the shareholders for the entire revenue requirement shortfall in the event the incremental capacity of the line is not fully subscribed by transmission customers, given, inter alia, the substantial increase in the cost of upsizing the pipeline. Suppose there are only one or two shippers, or the line is only at one-third capacity, unless it is opened and for some time thereafter. It is not right for ratepayers to be held responsible for paying for the entire shortfall.

BOMA notes that Ex M, T1, Sch 1, p1 states that the incremental capital cost of the upsizing the Segment A pipeline from 36" to 42" is now estimated at $105.6 million, up approximately one hundred percent (100%) from EGD's estimate of $55.1 million in the Joint Proceeding.

13. *Is the proposal to permit Enbridge to apply for changes in rate design and new energy and non-energy services during the IR term appropriate?*

BOMA is of the view that the proposal is appropriate.

14. *Is Enbridge's proposal to continue the RCAM methodology during the IR period appropriate?*

No. BOMA believes that the forecast RCAM accounts should be considered in the context of other forecast O&M expenditures. It should have no special status. BOMA also notes that EGD has peremptorily dismissed its own consultant's recommendations that it provide greater transparency and benchmarking for the increasing amounts being paid to Enbridge inc. The Board should direct EGD to make a more thorough report on the program at the earliest opportunity

15. *Is Enbridge's proposal to continue the current methodologies to cost and price other service charges and late payment penalties appropriate?*

BOMA supports this proposal.

16. *Are the overall levels of allowed revenue, rates and bill impacts for each of the years of the IR plan reasonable given the impact on consumers?*

They are not appropriate, given the rate impacts on customers. The cash payments (bill credits) to customers to mitigate the rate impacts are inappropriate for the reasons provided above.

B. Allowed Revenue and Rate Base

BOMA will comment on these detailed issues of O&M and capital on the assumption that regardless of the decision the Board makes with respect to the structure of the IRM, it will find the comments on the proposed amounts for 2014 are as helpful.

17. *Is the Allowed Revenue amount for each of 2014, 2015 and 2016 appropriate, including:*

    a. *Is the depreciation amount appropriate?*

Leaving aside the components of depreciation for SRC/ARO discussed in the answers to Questions 39 and 40, the depreciation amount is inappropriate as it is based on a forecast of the rate base in each of those years, which is based in turn, in part, on forecast capital expenditures in each of the years 2014, 2015, and 2016. BOMA's view is that EGD has not provided a case for the large increases in capital expenditure in each of these years, other than the GTA which has been approved by the Board.

EGD has made no serious attempt to reduce other aspects of the capital budget, or reflect the O&M savings from capital budget projects, such as WAMS. Every single capital budget dollar is stated to be non-discretionary. That position is simply not credible.

Maintenance of the artificial distribution between what EGD calls core capital, and the "major project" capital (GTA, Ottawa, WAMS), has further confused the situation. There should be no such thing as a core capital budget, every dollar of which must be spent regardless of other competing claims on resources.

b. Is the operating costs amount appropriate?

The increase in "other operating cost" forecast has also been deemed non-discretionary.

EGD proposes to increase operating costs by about 2% per year, which is well in excess of most current third party inflation rate estimates for 2014 and 2015. In particular, Bank of Canada's recent forecasts for 2014 and 2015 inflation are closer to 1% than 2%. As noted above, there is no evidence of sustainable energy improvements embedded in the operating cost forecasts.

c. Is the allocation of O&M costs between utility and non-utility (unregulated) operations appropriate?

BOMA has no position on this issue.

d. Is the amount for income and municipal taxes appropriate?

BOMA believes the method for calculating income taxes and property taxes is appropriate.

The amounts of tax are dependent on the net plant and earnings, which BOMA disputes.

e. *Is the cost of capital amount appropriate?*

See above. The cost of capital amount is not appropriate.

f. *Is the Other Revenues amount appropriate?*

BOMA adopts Energy Probe's position on this issue.

18. *Is the rate base for each of 2014, 2015 and 2016 appropriate, including:*

a. *Opening rate base*

See above.

b. *Forecast level of Capital expenditures*

See above.

c. *Forecast Customer additions*

BOMA adopts Energy Probe's submission on this issue.

d. *Proposed Capital additions*

See above.

e. *Allocation of the cost and use of capital assets between utility and non-utility (unregulated) operations*

BOMA supports the position taken by FRPO on this issue as to the allocations used to make the calculations.

f. *Working capital allowance*

BOMA supports the proposed Working Capital Allowance as corrected in TCU3.21.

g. *All other components of and adjustments to rate base*

BOMA takes no position.

19. *Is the preliminary Allowed Revenue amount for each of 2017 and 2018 appropriate, including:*

a. *Is the preliminary depreciation amount appropriate?*

These amounts are subject to the same objections as BOMA expressed in 18 above. In addition, these numbers are placeholders, given that the 2017 and 2018 capital budgets are simple extensions of the 2016 capital budget. EGD does not know what its capital budgets for 2017 and 2018 will be at this time (Sanders).

b. *Is the operating costs amount appropriate?*

See comments in response to Question 18 above. In addition, as noted above, EGD has simply used their O&M budget for 2016, as the O&M budget for 2017 and 2018. This is not a reasonable basis for forecasting O&M expenditures for that period. EGD does not know at this time what its O&M budget will be in 2017 and 2018.

c. *Is the allocation of O&M costs between utility and non-utility (unregulated) operations appropriate?*

See 18(e) above.

d. *Is the preliminary amount for income and municipal taxes appropriate?*

See above.

e. *Is the preliminary cost of capital amount appropriate?*

No. See discussion above.

f. Is the Other Revenues amount appropriate?

BOMA has no position on this issue.

20. *Is the preliminary rate base for each of 2017 and 2018 appropriate, including the method for establishing that preliminary level?*

No. See discussion at Question 18 above.

C. <u>2014 Rates</u>

21. *Is the 2014 forecast of Customer Additions appropriate?*

BOMA adopts Energy Probe's submission on this issue.

22. *Is the 2014 revenue forecast appropriate?*

BOMA supports the methodology used to arrive at the revenue forecast.

23. *Is the 2014 gas volume forecast appropriate?*

BOMA adopts Energy Probe's submission on this issue.

24. *Is the 2014 degree day forecast for each of the Company's delivery areas (EDA, CDA and Niagara) appropriate?*

BOMA adopts Energy Probe's submission on this issue.

25. *Is the 2014 Average Use forecast appropriate?*

BOMA adopts Energy Probe's submission on this issue.

26. *Is the 2014 level of Unaccounted For ("UAF") volume appropriate?*

BOMA adopts Energy Probe's submission on this issue.

27. Is Enbridge's forecast of gas, transportation and storage costs for 2014 appropriate?

BOMA supports this forecast, subject to its comments on issue 49.

28. Is the Allowed Revenue deficiency or sufficiency for the 2014 Fiscal Year calculated correctly?

Since some components of the revenue requirement are not appropriate, in particular, the cost of capital. Therefore, calculation of the sufficiency for 2014 is not appropriate.

Moreover, as noted above, the 2013 sufficiency (normalized actual) should be added to the sufficiency in 2014, and proposed 2014 rates adjusted accordingly.

29. Is the overall change in Allowed Revenue reasonable given the impact on consumers?

The overall change in Allowed Revenue is not reasonable, given the fact that:

(a) it does not take into account the actual 2013 sufficiency of approximately $37.8 million (Tr V.10, p28);

(b) it is premised on incorrect amounts for various cost components, including cost of capital, both equity and debt.

30. Is Enbridge's utility Cost Allocation Study, including the methodologies and judgments used and the proposed application of that study with respect to 2014 Fiscal Year rates, appropriate?

BOMA believes the cost allocation study to be appropriate.

31. Are the rates proposed for implementation effective January 1, 2014 and appearing in Exhibit H, just and reasonable?

The rates are not reasonable for the reasons given in the discussion of the revenue requirement components above.

32. *How should the Board implement the rates relevant to this proceeding if they cannot be implemented on or before January 1, 2014?*

Rates should be implemented on a cost of service basis for 2014. Since 2014 rates have been made interim, rates should be effective January 1, 2014 with refunds paid over the six month period commencing on July 1, 2014.

E. Other

36. *Is Enbridge's proposal for Transactional Services ("TS"), including the classification of transactions within TS and the treatment and sharing of TS revenues, appropriate?*

BOMA does not agree with EGD's proposal to remove the $8 million guarantee of the credit to the 2014 revenue requirement..

37. *Is the proposal to introduce a new Hybrid 50/50 forecasting methodology for the determination of a heating degree day ("HDD") forecast for the Company's "Central Delivery Area", and to retain the existing forecasting methodologies for the EDA and Niagara areas, appropriate?*

BOMA adopts Energy Probe's submission on this issue.

38. *Is the proposed implementation, treatment and cost recovery related to the change in the peak gas day design criteria, approved by the Board in the 2013 rate application (EB-2011-0354), appropriate?*

BOMA supports the implementation of treatment and cost recovery of the change in design criteria agreed in the EB-2011-0354 Settlement Agreement (p22), including the use of the 2013 and 2014 Design Day Criteria Transportation Deferral Account (DDCTDA).

39. *Are the proposed depreciation rate changes, to be in use beginning in the 2014 Fiscal Year, related to a reduction in the annual level of Site Restoration Cost/Asset Retirement Obligation ("SRC/ARO") collected, appropriate?*

  a. *Is Enbridge's proposal to continue with all other depreciation rates established in the EB-2011-0354 proceeding, throughout the IR period appropriate?*

40. *Are the proposed amounts to be returned to ratepayers over a 5 year period related to the estimated reduction to the amount of SRC/ARO previously collected, appropriate?*

EGD has proposed to reduce that component of its depreciation expense which relates to recovery of its forecast Site Restoration Cost/Asset Retirement Obligations ("Obligations") by approximately $33 million, in each of the next five years, and review the matter at rebasing (D1, T5, Sch 1, p10). Currently, EGD collects about $56 million from its customers, using EGD's language, "to fund the reserve" (I.A1.EGDI.CCC.2). EGD has indicated that in fact, there is no reserve; the funds have been used in the Company's normal business operations (notwithstanding the fact that EGD referred to a growing "reserve" in its reply to I.A1.EGDI.CCC.2.

In addition, EGD proposes to credit the customers' bills in amounts of $68.1 million, $63.1 million, $58.1 million, $53.1 million, and $17.4 million in 2014, 2015, 2016, 2017, and 2018, respectively, for a total of $259.8 million over the term of the IRM (K9.1, p1). This amount is a portion of EGD's "overcollection" from 1959 to the end of December 31, 2013 of approximately $905 million.

EGD is changing the annual depreciation amount charged in respect of net salvage going forward, on the advice of Gannett Fleming, its depreciation consultant. The rationale is that the lower annual amount to be collected in rates in the next five years will be sufficient to meet EGD's Obligations over time, without, at the same time, exacerbating the surplus in the "account". EGD's proposed credit to the customers is EGD's idea, with concurrence of Gannett Fleming and the amount of the annual refund was chosen based on a Gannett Fleming SRC/ARO study. EGD notes in an internal memo to its Board, that "these reductions will buffer the customer rate increases that would otherwise have occurred, beginning in 2014" (Ibid I.A1.EGDI.CCC.2).

The rapidly increasing "surplus" of the cumulative amount collected in rates to support Obligations relative to the cumulative actual expenditures for SRC/ARO to date, and relative to the forecast total SRC requirement for the existing in service assets, began to attract attention in 2009, when a change in Canadian GAAP required regulated entities like EGD to report their Obligations separately from the rest of their accumulated depreciation as a regulatory liability, in their financial statements. Before that time, EGD and other regulated entities had lumped their SRC related depreciation in with their normal depreciation relating to the declining value of their assets over time. The EGD SRC liability obligation was first reported as $760 million on December 31, 2009, but grew to $905 million by December 31, 2013. The amount of $905 million is noted at footnote 13 to the 2013 Financial Statement as a Regulatory Liability. Given that EGD's long term debt was $2,399 million at December 31, 2013, the Obligation constituted about 35% of the Company's long term obligations. That was certainly large enough to attract the attention of investors (in preferred shares) and lenders, as well as management. Further, the evidence indicates that, even with the lower annual depreciation amount for SRC going forward, the forecast gap between the annual depreciation accrual and the forecast actual SRC expenditure remains substantial, so much so that the amount of the

Obligation will increase by a further $150 million over the period 2014-2018. EGD has noted that:

> "History has shown that the actual annual costs incurred and charged against this reserve are significantly less than the rate at which the reserve is growing" (I.A1.EGDI.CCC.2, p3).

Interest was never accumulated on the amount.

The $905 million liability was recorded as a long term liability, in the section in the 2013 Financial Statements, entitled "Financial Statement Effects of Rate Regulation" (Ex J1.1, Attachment 5, p15; List of Regulatory Assets and Liabilities). The List was preceded by the following explanatory paragraph:

> "As a result of rate regulation, the Company has recognized a number of regulatory assets and liabilities. Regulatory assets represent amounts that are expected to be recovered from customers in future periods through rates. <u>Regulatory liabilities represent amounts that are expected to be refunded to customers in future periods through rates</u>" (our emphasis).

Footnote 10 to the List described the item as follows:

> "Future removal and site restoration reserves result from amounts collected from customers by Enbridge Gas Distribution, with the approval of the OEB, to fund future costs for removal and site restoration relating to property, plant and equipment. These costs are collected as part of depreciation charged on property, plant and equipment. The balance represents the amount that Enbridge Gas Distribution has collected from customers, net of actual costs expended on removal and site restoration. The settlement of this balance will occur over the long-term as future removal and site restoration costs are incurred. In the absence of rate regulation, costs incurred for removal and site restoration would be charged to earnings as incurred with recognition of revenue for amounts previously collected".

EGD has testified that this proposal stands separate and apart from its IRM plan, and is a step it would have taken regardless of what kind of rate plan it had proposed (Brett).

EGD proposes the refunds to be as a credit to customers' bills, relative to what those bills would have been otherwise, in each of the years 2014 through 2018.

BOMA supports the SRC initiative as a separate initiative on the grounds that it is a repayment of a portion of monies EGD has collected from ratepayers since 1959, which Gannett Fleming has said is surplus to future requirements for SRC/ARO. The surplus is money that effectively belongs to ratepayers. Mr. Bonbright has referred to it as a form of "ratepayers equity". However, EGD should not be able to use the refund against the increase in customer bills that would otherwise occur as a result of its proposed large increase in costs and returns and the revenue requirement in its custom IR proposal as a justification for that proposal. EGD has admitted that it would have made the payments in any event. Moreover, the funds are reported in the Financial Statements as long term obligation to the Company's ratepayers. They are held in trust for the ratepayers, subject only to any future amounts that may be required for SRC/ARO. Lenders would naturally be concerned about the existence of such a large liability on the company's balance sheet, and would include it in the credit analysis. So EGD had another reason to make a distribution.

Finally, while the amounts that EGD has collected in respect of its SRC/ARO obligations have been determined by its consultants, the effect of the arrangement is that EGD has received an interest free loan from ratepayers increasing gradually to $905 million as at December 31, 2013. EGD has testified that the funds have been used in the normal course of business; no cash reserve has ever been created. It has, therefore, had to borrow less funds on the capital markets, and issue less preferred shares than it would have had to have done otherwise. Because of this, BOMA believes that an amount should be deducted from the revenue requirement each year going forward equivalent to the foregone interest on the outstanding liability as at December 31st of the previous year with interest calculated at the level of EGD's embedded cost of long term debt. The details of over what period the amount of foregone interest realized to date should be amortized needs to be worked out by EGD in conjunction with its ratepayers.

EGD notes the cash refunds and the change in the depreciation rate going forward will have significant impacts on EGD rate base, and taxes, and accumulated depreciation in each of the five years of the IRM plan. The effect of the payments will be to increase the rate base, over what it otherwise would have been in each year of the IRM plan. Those impacts are set out at K9.1. The lower annual depreciation charge going forward will, in itself, reduce the revenue requirement by the amount of the actual reduction (adjusted for taxes), but will also increase the Company's accumulated depreciation and therefore increase rate base and the return component of the revenue requirement. The cash payments will reduce the tax component of the revenue requirement, since they are deductible to the company for income tax purposes. However, the cash payment will be taxable to business customers. However, in BOMA's view, the impacts to ratepayers in 2014 would have been the same, if EGD had proposed a cost of service treatment for 2014, and the same would have been true for each of the subsequent years, had a cost of service approach been used for those years. EGD agreed that the effect in 2014 would be the same for a one year 2014 cost of service application for 2014. Moreover, the effect would have been similar if EGD had proposed an I-X IRM, save for the fact that the adjustments to the components of the revenue requirement would be deferred until rebasing. So the impacts of a change in depreciation amount going forward and the annual cash refunds would be similar regardless of the IRM plan cost of service approach chosen.

41. Is the proposal for the Open Bill Access Program appropriate?

BOMA takes no position on the Open Bill Access Program.

42. Are the proposed changes to Rate 100 and Rate 110 appropriate?

BOMA supports the proposed changes to Rate 100 and Rate 110.

43. Are the proposed changes to the Rate Handbook appropriate?

BOMA has no position on this matter.

44. Is Enbridge's rate design for the proposed Rate 332 appropriate?

EGD provides only skeletal evidence on the structure of Rate 332.

In its EB-2012-0451, EB-2012-0433, and EB-2013-0074 (the "Joint Proceeding"), the Board issued EGD leave to construct Segment A of the GTA, which EGD refers to as the Albion pipeline. The Albion pipeline will have a design capacity of 2,000,000 GJs/day of which EGD will use 800,000 GJs/day (40% of total capacity). The remaining 1,200,000 GJs/day (60% of capacity) will be offered to potential transmission customers, including TCPL.

EGD had initially proposed a 36 inch pipeline, of which EGD and TCPL would each take 800,000 GJs/day. However, EGD later decided to increase the size of the pipeline to 42 inches to include a larger transmission component.

The cost of upsizing the line was initially estimated at $55 million (it was acknowledged to be an approximation only) (EB-2012-0451, Ex A, T3, Sch 9, p5 of 16). However, the most recent estimate (EB-2012-0459, Ex M, T1, Sch 1, p1) states that the upsizing cost has increased to $105.6 million.

In its evidence in the Joint Proceeding, EGD noted that:

> "Enbridge will be working with shippers on the Segment A pipeline to include placement of Financial Backstopping Agreements ("FBAs"). The shippers are expected to bear some of the risk on upfront costs associated with the Segment A pipeline, in particular the approximately $55 million in cost associated with NPS 42 as compared to NPS 36 and also any consequences of a delay in the build out of the Albion to Maple path ".

EGD did not provide an update in this case of its efforts to have shippers provide financial assurances as part of its evidence relating to either Rate 332 or the Greater Toronto Area Incremental Transmission Capital Revenue Requirement Deferral Account (Ex D1, T8, Sch 7, p1).

BOMA assumes that EGD would not commence construction of the line until it had several suitable financial assurances from proposed transmitters as is customary in the gas transmission business.

In the Joint Proceeding, EGD proposed a rate methodology which provided for 40% of the fully allocated revenue for the Albion Pipeline to be recovered from EGD customers other than Rate 332 customers, and 60% from Rate 332 (transmission) customers. The Company noted:

> "This approach ensures proper separation and allocation of costs between the transportation and distribution services" (EB-2012-0451, Ex E, T1, Sch 2).

In Attachment 1 to that evidence, the Company displayed the Revenue Requirement for the Albion Line for the years 2015, 2016, 2017.

In the Joint Proceeding decision, the Board stated that:

> "the detailed rate design will be examined through a separate proceeding, at which time parties will have an opportunity to review the issue in greater detail" (EB-2012-0451, p51).

Unfortunately, given the magnitude of and focus on the large structural issues in this proceeding, there has been no substantive examination of the proposed Rate 332.

The evidence itself is skeletal, and the rate shows no monthly charge, only the statement that the Rate 332 monthly charge will recover shipper's share of the annual revenue requirement through a contract demand charge for contract.

The evidence does not indicate how the shipper's share is to be determined, including whether a range rate concept would be used as originally proposed.

Given the 100% increase in the cost of the upsize, and the lack of detailed evidence and examination of the rate in this case, BOMA recommends that the Board not decide on the rate at this time, but rather in the 2013 ESM proceeding or the 2015 rate adjustment proceeding later this year.

45. Is the rate of return on the Natural Gas Vehicle ("NGV") program appropriate?

BOMA supports the rate of return on the NGV program, because it continues to support EGD's innovation with respect to natural gas utilization in transportation. Given the accelerated efforts in North America to increase the use of natural gas in truck fleets, and ongoing work by the GGA, the AGA, and many utilities, it is appropriate for Canadian Gas LDCs to maintain a presence in this area.

46. *Has Enbridge responded appropriately to all relevant Board directions from previous proceedings, including commitments from prior settlement agreements?*

BOMA believes that EGD has responded to all relevant Board directions including commitments from the previous Settlement Agreement.

47. *Are Enbridge's economic and business planning assumptions appropriate?*

As noted earlier, EGD needs to update its forecast inflation rate for 2014 and 2015, given recent Bank of Canada forecasts, including the January 2014 Monetary Policy Report.

48. *Is Enbridge's updated asset plan appropriate?*

BOMA has no position on EGD's asset plan, other than to note, as others have, that it appears to have no direct link to EGD's capital budgets.

49. *Is Enbridge's proposal to increase firm transportation for 2014 appropriate? What are the implications, if any, of that proposal on the gas supply and transportation strategy for 2015-2018? What is the appropriate process to develop, review and approve the gas supply and transportation strategy for 2015-2018?*

BOMA agreed with EGD's proposal to increase its firm transportation in 2014, given TCPL's changes to its IT and STFT rates since the NEB's March 2013 decision.

As per the agreement in the EB-2011-0354 Settlement Agreement, and the discussions with stakeholders in October 2013, described in EGD's evidence, EGD should prepare a 2015 gas supply Report and Plan for review by stakeholders during the 2013 ESM proceeding, and for each annual ESM proceeding during the IRM. More generally, BOMA has had the opportunity to see FRPO's draft submissions on this issue. BOMA supports those submissions.

BOMA respectfully requests that it be awarded 100% of its reasonably incurred costs associated with its participation in this hearing.

ALL OF WHICH IS RESPECTFULLY SUBMITTED, APRIL 22, 2014

Tom Brett

Tom Brett, Counsel to BOMA

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