ENBRIDGE GAS DISTRIBUTION INC. AND UNION GAS LIMITED

Answer to Interrogatory from
Building Owners and Managers Association ("BOMA")

MAADs Issues List – Issue No. 1

Reference: pp 20-21, Table 3

Question:

(a) To allow BOMA to better understand Table 3, please provide detailed background information in support of the proposed annual rebasing revenue requirement in 2019, and the forecast increase in annual costs each year for the next ten years, for both capital and OM&A costs (separately).

Preamble: In describing the stand-alone option, shown in Table 3, the applicants state: "The revenue requirement for the stand-alone utilities shown at lines 1 through 3 in Table 3 represents status-quo operations for the deferred rebasing period based on the following assumptions:

- EGD and Union would rebase in 2019 and 2025 and rates are set using a Custom IR framework during the 2020 to 2024 and 2026 to 2028 periods;
- Capital expenditures are based on the utilities' Asset Management Plans to support growth and replacement and maintenance of existing assets. The combined growth reflects customer attachments of an average of 45,000 per year consistent with historic trends.
- Operating costs increase for inflation and growth, pension and other programs related to asset management."

(b) Please provide copies of the Union and the EGD Asset Management Plans.

Response

a) Please see the response to FRPO Interrogatory #11(a) found at Exhibit C.FRPO.11, as follows:

- For 2019 revenues, please see Table 2 and Table 6 for EGD and Union respectively
- For capital cost, please see Table 1, Line 3.1 and Table 5, Line 3.1 for EGD and Union respectively
- For O&M cost, please see Table 1, Line 2 and Table 5, Line 2 for EGD and Union respectively

b) Please see the response to Board Staff Interrogatory #54 found at Exhibit C.STAFF.54.

ENBRIDGE GAS DISTRIBUTION INC. AND UNION GAS LIMITED

Answer to Interrogatory from
Building Owners and Managers Association ("BOMA")

MAADs Issues List – Issue No. 1

Reference: General

Question:

(a) Given that the Board's statutory objectives for natural gas include the facilitation of competition in the sale of gas used (section 2.1), and that EGD and Union are by far the largest sellers of gas to users, especially residential and small business users, and given that "competition" should be viewed to include not only price competition, but competition in the variety of options for gas service available, please explain why the creation of a single gas utility for virtually the entire Ontario market is not harmful to customers as it will reduce the options available to them.

(b) Currently, with two strong management teams in place, customers benefit from the innovation and best practice of each of the utilities often being adopted by the other large utility (see the number of times adoption of best practices from one to another have been advanced as benefits of the merger), due to the "competition" between the two organizations to meet regulatory pressures and innovate more vigorously than their counterpart. Please explain why the removal of the incentive to develop best practices going forward does not leave ratepayers of each utility worse off than today.

Response

a) The Board's statutory objective to the facilitate competition in the sale of gas to users relates to deregulation of the commodity market and customer choice as to the entity from whom they purchase that commodity. The amalgamation of Union and EGD will have no impact on the commodity market for natural gas and customers will continue to have choice when it comes to its purchase. Accordingly, there is no harm as a result of the amalgamation.

b) With the exception of non-utility storage, Union and EGD do not compete. They are regulated monopolies. Each individual utility's drive to innovate and adopt best practices during the term of their respective incentive mechanism terms is in effort to maximize utility return which benefits ratepayers through earnings sharing and at rebasing. Amalco will have the same incentive to innovate and adopt best practices during the deferred rebasing term.

ENBRIDGE GAS DISTRIBUTION INC. AND UNION GAS LIMITED

Answer to Interrogatory from
Building Owners and Managers Association ("BOMA")

MAADs Issues List – Issue No. 1

Reference: Exhibit B, Tab 1, p3

Question:
The evidence notes that amalgamation allows for greater operating efficiencies including potential economies of scale, as well as continuous improvement through best practices.

(a) Please provide details of the greater operating efficiencies that will be achieved as a result of the merger. Please specify each area of operation, the nature of the efficiencies to be achieved, when such efficiencies would begin, and the cost savings to Amalco that would result.

(b) Potential Economies of Scale - Given that both Union and EGD are already very large companies, why should we expect further material economies of scale?

(c) Please provide the details on the various economies of scale that will be realized, the dollar value of each such economy of scale, the likelihood of it being achieved, and in what year such economies would commence.

(d) Given that the two companies occupy largely different franchise areas, is it realistic to expect material reduction in the combined staff of the two companies, other than perhaps at the senior management level? Please discuss.

(e) Please provide an estimate of the likely FTE reduction and the associated cost savings as a result of amalgamation. Please identify such reduction and savings for each of senior management, middle management, professionals including engineering/legal, financial, administrative, IT, field staff, and any other identifiable category of employees.

(f) To what extent will existing contracts allow such reductions? Which categories?

(g) Please provide the magnitude of any other quantifiable benefits arising from the merger to Amalco and its customers.

(h) Given the fact that the rate base, OM&A and taxes, and debt of the two companies, will be added together as a result of the merger, please confirm that the merged company should be able to earn a return equivalent to the existing rates of return of Union and EGD.

(i) Please confirm that because Union and EGD are already under common ownership, and have been for the last year, and that there is consequently the ability for EGD to access the important business information of Union, and vice versa, the risks of the merger are substantially reduced relative to a merger of two arms-length companies where transfer of information prior to the closing of the merger is much more limited, creating greater risks.

(j) Given that neither Union nor EGD has had a cost of service (rebasing) proceeding since 2013, and given the complexity of merging two large companies, does it not make sense to start the merged entity off with a thorough cost of service hearing? Will not this process serve the public interest in allowing the Board and intervenors and the company transparency on the "going-in" costs for the new regime? The cost of service hearing would be followed by an IRM plan, either price cap or custom IR plan? Please discuss fully.

Response

a) Please see the response to BOMA Interrogatory #16d) and i), found at Exhibit C.BOMA.16 which provides details on Management's high level integration planning.

b) EGD and Union have optimized workforces and internal processes as stand-alone utilities. The proposed amalgamation provides the two utilities enhanced opportunities during the ten year deferred rebasing term to further optimize workforces, internal processes and the similar systems that each company currently uses. Ratepayers will benefit from material economies of scale in many forms throughout the ten year deferred rebasing term and at rebasing in 2029.

The Applicants' approach to amalgamation and achievement of economies of scale has been informed by the OEB's RRF guidance that results, rather than activities, are the core to a performance based approach to regulation. Throughout the ten year deferred rebasing term, customer experience benefits will be achieved by the selection of best practices from each utility implemented through integration activities. The integration of external websites and internal systems to incorporate the best practice from both utilities in the areas of processing of information, external communication and a customer's access to information will deliver a single suite of systems that will enhance the utilities' services being provided in a manner that responds to customer needs. Customer Focus is one of the RRF outcomes that is appropriate for distributors.

The integration of all software systems will also provide sustainable savings, which can be linked to the operational effectiveness outcome stated in the RRF. In simplified terms, the integration of systems will allow for the adoption of a single process wherever similar functions are being conducted at the two utilities. Integration of software systems is another way the utilities continue to demonstrate that continuous improvement in productivity and cost performance is being achieved from this amalgamation. The Applicants' prefiled evidence as well as additional information in BOMA Interrogatory #16d) found at Exhibit C.BOMA.16 provide additional context to how amalgamation meets the operational effectiveness.

EGD's recent GeoThermal and RNG facilities application demonstrates Public Policy Responsiveness - another RRF outcome. Having one voice at the OEB as well as the Ontario Government should enable quicker and more responsive delivery of obligations mandated by the government. This amalgamation application demonstrates Public Policy Responsiveness in that it is consistent with the goals of the Minister of Energy and the OEB to incent consolidations leading to reductions in the long term cost of energy to ratepayers.

These reasons support why ratepayers should expect economies of scale in many forms, the amalgamation's alignment with the RRF and Management's commitment to ratepayer benefit.

c) Please see the response to BOMA Interrogatory #16d), found at Exhibit C.BOMA.16.

d) Detailed integration planning will not be undertaken until the Board's decision is known and all approvals to proceed obtained and as a result there is no detail on the overall staff reductions. Please see the response to BOMA Interrogatory #16d), found at Exhibit C.BOMA.16 for context to the high level planning that Management has conducted on management function efficiencies.

e) See the response to part d).

f) Please see the response to BOMA Interrogatory #16d), found at Exhibit C.BOMA.16.

g) Please see the response to BOMA Interrogatory # 16d), found at Exhibit C.BOMA.16.

h) The combined utility earning a return equivalent to the existing rates of return of Union and EGD will be dependent on several factors including any OEB adjustments to the Applicants' proposals in EB-2017-0306/0307. Any adjustments to the proposed Productivity Factor, Earnings Sharing Mechanism, proposed base rate adjustments or ten year deferred rebasing term may impact the ability to earn the utility rate of return. As seen in the response to FRPO Interrogatory #1, Attachment 1, Slide 23, found at C.FRPO.1, the combined utility earns slightly over the forecasted return on equity over the ten year period as a result of the high level estimate of net O&M savings.

i) There has not been any significant reduction to the risks of the amalgamation as a result of Union and EGD operating under a common parent. There has not been any detailed integration planning conducted that would commence the process of sharing the significant information that will be needed to produce a quality integration plan. EGD and Union operate at arms-length, operating as affiliates adhering to the Affiliate Relationship Code.

j) Under the MAADs policy, utilities transfer from their current IRM to a Price Cap model without a rebasing. The principles of this are that the utilities have not amalgamated and therefore would not be able to produce a quality cost of service application as an amalgamated entity. The best time to conduct a full cost of service application is after the integration of the utilities is completed. Any utilities that have not received approval to amalgamate should not be communicating the required details that would be necessary to produce a full study or analysis of what the cost structure of the ultimate amalgamated utility would be. The Applicants' proposal is consistent with the MAADs policy and principles and therefore, the Applicants disagree with the assertion of this question.

ENBRIDGE GAS DISTRIBUTION INC. AND UNION GAS LIMITED

Answer to Interrogatory from
Building Owners and Managers Association ("BOMA")

MAADs Issues List – Issue No. 1

Reference: *Ibid, p3*

Question:
The applicant states that "continuous improvement through best practices will result from the merger". Given the fact that each of EGD and Union are very large, mature companies, that consistently innovate and develop best practices in their own franchise area, and that in these circumstances, one company can learn from the advancement of best practices of the other, and would do so as a financial and reputational matter and to meet ratepayer and regulatory pressures, is it not likely that the incentive to develop additional best practices will decline under the merger, after which one company (Amalco) will serve 98% of the Ontario market?

Response

Please see the response BOMA Interrogatory #2 (b) found at Exhibit C.BOMA.2.

ENBRIDGE GAS DISTRIBUTION INC. AND UNION GAS LIMITED

Answer to Interrogatory from
Building Owners and Managers Association ("BOMA")

MAADs Issues List – Issue No. 1

Reference: General

Question:
With respect to the proposed merger, please confirm that:

(a) the merger is not being done pursuant to the requirement of any law, regulation, directive, or policy, relating to natural gas, of the Government of Ontario, or the Minister of Energy of Ontario. If you cannot confirm any part of this question, please discuss fully;
(b) the merger is not being done pursuant to any order of the Ontario Energy Board directing such a merger;
(c) the primary purpose of the merger is to increase the profitability of the combined company, relative to the profitability of EGD and Union, in particular, during the requested ten-year rebasing period due to the fact that the forecast savings from the merger over the ten-year period are far larger than the forecast implementation costs and transaction costs, as outlined in Exhibit B, Tab 1, Attachment 12, and Exhibit B, Tab 1, page 20 of 44.

Response

a) Confirmed.

b) Confirmed.

c) Not confirmed. The purpose of the amalgamation and the deferred rebasing period is to allow Amalco to integrate systems and business processes that will ultimately result in sustainable benefits for ratepayers. Please also see the responses to BOMA Interrogatory #3(b) found at Exhibit C.BOMA.3 and Board Staff Interrogatory#37 found at Exhibit C.STAFF.37.

ENBRIDGE GAS DISTRIBUTION INC. AND UNION GAS LIMITED

Answer to Interrogatory from
Building Owners and Managers Association ("BOMA")

MAADs Issues List – Issue No. 1

Reference: *Ibid, p44*

Question:

(a) Given the size and maturity of the two merging companies, Union and EGD, please explain in detail how the merger is required to allow for "greater strategic focus and capability to face the challenges and opportunities of what developments in the Ontario energy sector". Please be as specific as possible in your response.

Response

Please see the response at BOMA Interrogatory #3(b) found at Exhibit C.BOMA.3.

ENBRIDGE GAS DISTRIBUTION INC. AND UNION GAS LIMITED

Answer to Interrogatory from
Building Owners and Managers Association ("BOMA")

MAADs Issues List – Issue No. 2

Reference: Exhibit B, Tab 1, p17

Question:
(a) The applicants have indicated at p 17 of 44 that the transaction costs related to the amalgamation are not material. Please provide the amount of transaction costs incurred to date and the estimate of future transaction costs until December 31, 2018.
(b) The evidence states that "all transaction costs will be largely incurred, paid for, and financed, prior to January 1, 2019, and hence will be borne by the EGD and Union shareholders, and not by ratepayers" (our emphasis).
    (i) Will transaction costs incurred, paid for, or financed, after January 1, 2019 be paid for by ratepayers? Please explain.
    (ii) What amount of transaction costs will be incurred, paid for, and financed after December 31, 2018?

Response

a) The transaction costs incurred to date relate to outside legal counsel. As of March, 2018 the transaction costs are approximately $800,000. No estimate of future transaction costs has been completed.

b) To the extent that there are any transaction costs after January 1, 2019, they will be borne by Amalco. The revenue requirements for each of EGD and Union do not include transaction costs. Further, one of the purposes of deferred rebasing is to ensure that the transaction costs are not recovered from customers, but rather are recovered through savings. No estimate of future transaction costs has been completed.

ENBRIDGE GAS DISTRIBUTION INC. AND UNION GAS LIMITED

Answer to Interrogatory from
Building Owners and Managers Association ("BOMA")

MAADs Issues List – Issue No. 2

Reference: *Ibid, p 23*

Preamble: *"In addition, Amalco will face risks associated with the changing economic environment with respect to interest rates and the move to a lower carbon economy".*

Question:
Please confirm that Amalco will face the same risks related to the risks noted in the preamble as Union and EGD would face in the stand-alone case.

Response

Please see the response to LPMA Interrogatory #7 found at Exhibit C.LPMA.7.

ENBRIDGE GAS DISTRIBUTION INC. AND UNION GAS LIMITED

Answer to Interrogatory from
Building Owners and Managers Association ("BOMA")

MAADs Issues List – Issue No. 2

Reference: p 26, Table 4, Capital Investment, OM&A Reduction and OM&A Savings

Question:
Union and EGD have been under common control since February 2017, and have already begun communication about how to achieve economies from the merger. Please modify Table 4 to show the proposed capital expenditures and potential OM&A savings in each year of the ten year period.

Response

Table 4 represents high level estimates of the potential range of capital investments and Net O&M cost savings. Please see the response to BOMA Interrogatory #16(d) found at Exhibit C.BOMA.16 for additional context on how the ranges in Table 4 were estimated. The Applicants have only conducted a high level planning exercise and do not have a yearly profile of the range outlined in Table 4 and therefore will not be providing this request.

ENBRIDGE GAS DISTRIBUTION INC. AND UNION GAS LIMITED

Answer to Interrogatory from
Building Owners and Managers Association ("BOMA")

MAADs Issues List – Issue No. 2

Reference: Capital Structure, p13

Question:
(a) Please explain why Union and EGD plan to redeem their issued and outstanding preference shares prior to amalgamation.

(b) Please provide details of each class of preferred shares that EGD and Union currently have outstanding including information on redemption conditions, procedures, and premiums payable to redeem the shares prior to the end of the term.

(c) Please provide the costs incurred in such redemption, relative to leaving the preferred shares outstanding, including penalties, premiums for early redemption, and the like, as well as the redemption transaction costs per sé.

(d) Please confirm that any costs associated with the redemption of preferred shares, including redemption premiums, or market losses, are for the shareholders' account.

(e) Please advise of any other changes to the capital structure the two companies propose to make prior to amalgamation.

(f) Please provide copies of any reports of rating agencies on Enbridge Inc., Enbridge Gas Distribution, and Union Gas Ltd., issued in the last eighteen months.

Response

a) Both Union and EGD are seeking to streamline and simplify their capital structures, and that of Amalco, over the longer term. Their goal is to minimize administrative costs associated with maintaining and administering numerous classes of issued and outstanding preference shares, some of which are currently listed on a recognized exchange. The proposed articles of Amalco will enable issuance of preference shares in classes in the future, should that prove to be a prudent funding mechanism at a future date.

In the near term, redemption of the preference shares also simplifies the process of amalgamating Union and EGD, again mitigating associated costs and complexity.

b) Preference Share Classes and relevant details are summarized below:

Enbridge Gas Distribution Preferred Shares

Shares Outstanding: 4,000,000 Floating Cumulative Redeemable Preference Shares, Group 3, Series D and are not listed on the Toronto Stock Exchange.

Amount: $100,000,000

Price: $25.00 per Preferred Share

Rate: 80% of the Prime Rate payable quarterly (after July 1, 2002)

Redemption: The preferred shares are redeemable at the Issuer's option on and after July 1, 2002 by payment in cash for each preferred share an amount equal to the then applicable redemption price, together with accrued and unpaid dividends to but excluding the date of redemption. The redemption price per preferred Share is $25.

Based on the above the actual cost of redemption is limited to the redemption price of $25 per share plus applicable administrative costs.

Union Gas Preferred Shares

- 5.5% Cumulative Redeemable Class A Preferred Shares, Series A, of which 47,672 shares are issued and outstanding and are listed on the Toronto Stock Exchange;

- 6% Cumulative Redeemable Class A Preferred Shares, Series B, of which 90,000 shares are issued and outstanding and are listed on the Toronto Stock Exchange;

- 5% Cumulative Redeemable Class A Preferred Shares, Series C, of which 49,500 shares are issued and outstanding and are not listed on the Toronto Stock Exchange; and

- 4.88% Cumulative Redeemable Convertible Class B Preferred Shares, Series 10, of which 4,000,000 shares are issued and outstanding and are not listed on the Toronto Stock Exchange.

The Class A Preferred Shares, Series A and Class A Preferred Shares, Series C are cumulative and redeemable at $50.50 per share. Union is obligated to offer to purchase $170,000 of Series A and $140,000 of Series C shares annually at the lowest price obtainable, but not exceeding $50 per share. The Class A Preferred Shares, Series B are cumulative and redeemable at $55 per share at the option of Union.

The Class B Preferred Shares, Series 10 are cumulative and redeemable at $25 per share at the option of Union and, at the option of the holders, convertible back into Series 11 shares once every five years, commencing January 1, 2014. The holders of the Class B Preferred Shares, Series 10 did not exercise their option on January 1, 2014 and their next optional conversion date is January 1, 2019. Union may redeem at any time all, but not less than all, of the outstanding Class B Preferred Shares, Series 10. The dividend rate of the Series 10 shares is floating at an annual rate equal to 80% of the prime rate until December 31, 2018.

Total value of Preferred Shares at Union Gas as of December 31 was $110,000,000

The preferred shares at Union and EGD represent a very small portion of the capital structure at 1.8% and 1.2% respectively. There is no requirement to have the preferred shares remain outstanding as part of amalgamation. For rate making purposes, since the preferred shares receive a floating rate based on 80% of the Prime Rate it is treated as the equivalent of debt.

The redemption of the preferred shares will not negatively impact the capital structure of Amalco as Enbridge remains committed to maintaining the Regulatory allowed capital structure of 64% debt and 36% and financing plans have been and will be designed to ensure that this ratio is achieved annually on the Utilities' outstanding rate base.

c) The majority of transactional advisory work will be done internally through the existing services provided from the Enbridge Inc. Treasury and Corporate Secretarial groups, under existing intercorporate services agreements. The costs to redeem the shares is nominal as described in part b).

d) Confirmed.

e) There are no other changes contemplated.

f) Please see the response to SEC Interrogatory#20 found at Exhibit C.SEC.20.

ENBRIDGE GAS DISTRIBUTION INC. AND UNION GAS LIMITED

Answer to Interrogatory from
Building Owners and Managers Association ("BOMA")

MAADs Issues List – Issue No. 2

Reference: *Ibid, p17*

Preamble: *"The evidence suggests that Amalco has undertaken to maintain a substantial presence in Chatham".*

Question:

(a) Please list the number of FTEs and personnel at Union's Chatham facilities at this time, and the number of FTEs, personnel, that will remain at Amalco's Chatham facilities two years after the amalgamation is approved, if it is approved.

(b) Has Amalco entered into an agreement with the City of Chatham, or does it intend to enter into an agreement with the City (and, if so, when), which will guarantee a specific level of personnel that will be located in Chatham, whether at Union's existing facilities or otherwise, or a set of principles or guidelines that will be used to determine the size of the continuing presence in Chatham? Please provide details of the agreement or informal commitment.

(c) Please provide a copy of, or a link to, documents filed by Enbridge Inc. with either the OSC or the SEC, in connection with the acquisition of Spectra Inc. Please provide a list of such documents.

Response

a) No detailed integration plan has been prepared. Please see response to the Municipality of Chatham Kent Interrogatory #1 found at Exhibit C.MCK.1 and Board Staff Interrogatory #12 found at Exhibit C.STAFF.12.

b) Please see part a)

c) Please use the following link to the SEC filings: https://www.sec.gov/cgi-bin/browse-edgar?action=getcompany&CIK=0000895728. Documents relevant to the Enbridge Inc. acquisition of Spectra would only pertain on or after September 6, 2016 and no listing of such documents is available.

ENBRIDGE GAS DISTRIBUTION INC. AND UNION GAS LIMITED

Answer to Interrogatory from
Building Owners and Managers Association ("BOMA")

MAADs Issues List – Issue No. 2

Reference: *Ibid, p26*

Question:

(a) Please provide an estimate of the number of personnel removed and the savings that will be achieved by the reduction of compensation, both management and non-management, due to the merger. Please show these savings for each year from 2019 to 2028, with an explanation for the amount of savings in each year.

(b) Aside from the reduction due to elimination of duplicate management shown in line 5 of Table 4, what percentage of "potential OM&A savings" shown on p26, Table 4 are due to reduction in total personnel compensation? Please provide data for each line.

(c) Why is it necessary to align all the business practices between the two parts of Amalco?

(d) Does the comparison of the cost per customer between the two companies include Union's transmission business?

Response

a) Please see the response to BOMA Interrogatory#16(d) found at Exhibit C.BOMA.16.

b) The Applicants have conducted a high level integration planning exercise which did not produce a detailed plan of staff reductions and associated savings.

c) Please see the response to BOMA Interrogatory #3(b) found at Exhibit C.BOMA.3.

d) Yes, Union's cost per customer in Table 1 does include their transmission business.

ENBRIDGE GAS DISTRIBUTION INC. AND UNION GAS LIMITED

Answer to Interrogatory from
Building Owners and Managers Association ("BOMA")

MAADs Issues List – Issue No. 2

Reference: Exhibit B, Tab 1, Attachment 11

Question:

a) Please show how the Pro Forma Income Statement, Balance Sheet, and Statement of Cash Flow were assembled from existing Union and EGD 2017 Financial Statements.

b) Please provide comparable pro forma statements for each year from 2020 to 2028. In so doing, please explain how each year's pro forma statements were created based on modifications to the pro forma statement for the previous year.

c) Please provide the details of the proposed ACM and/or ICMs that are included in the estimate of the Revenue Requirement. Please show the amount of the proposed ICM/ACM for each year.

Response

a) Please see the response to BOMA Interrogatory #22a), found at Exhibit C.BOMA.22, regarding how the Pro Forma statements were assembled.

b) The Applicants are not able to provide proforma statements for each of the deferred rebasing years. The effort involved in attempting to create these would be significant. Information on the financial projections of Amalco can be found at Exhibit B, Tab 1, Table 3 and the response to FRPO Interrogatory #11, found at Exhibit C.FRPO.11.

c) This application is not requesting approval for the ICM projects; this approval will be requested in the 2019 Rates application. The 2019 forecasted revenue requirement includes $111 million in capital expenditures in excess of the illustrative ICM threshold for EGD and $211 million in capital expenditures in excess of the illustrative ICM threshold for Union as shown in Table 14 and Table 17 in the response to FRPO Interrogatory #11a), found at Exhibit C.FRPO.11.

ENBRIDGE GAS DISTRIBUTION INC. AND UNION GAS LIMITED

Answer to Interrogatory from
Building Owners and Managers Association ("BOMA")

MAADs Issues List – Issue No. 2

Reference: *Ibid, p42*

Question:
Amalco has stated that it may apply for further rates using an ICM at any time during the ten-year rebasing period. Given the fact that Amalco proposes to recover all of its merger implementation capital expenditures through its 100% share of the savings created by such expenditures, please provide a more definitive statement on whether and to what extent Amalco plans to make use of ICM funds during the proposed ten-year rebasing deferral period, and for what purpose. Please discuss:

(a) in which year does it propose to apply for an ICM;
(b) does it propose to do so in 2019, 2020, or 2021;
(c) what specific projects does Amalco propose to include in such ICM requests? Please discuss the categories of expenditures, eg. system access (both moves to accommodate shifts in provincial/municipal/agency infrastructure, and to connect new gas loads, to comply with change policy, system renewal/replacement, public policy related expenditures, capital expenditures, and general plant.
(d) for what amounts, in which years, does Amalco propose to seek ICM support? If the exact amounts are not yet known for the out years, please provide a range;
(e) please confirm that none of the capital expenditures fall in the category of implementation expenditures, which have been described at B1-1, Attachment 12.

Response

a) Please see EB-2017-0306, Exhibit B, Tab 1, page 15, Lines 7 to 16.

b-d) Please see the response to Board Staff Interrogatory #5(b) found at Exhibit C.STAFF.5.

e) Confirmed.

ENBRIDGE GAS DISTRIBUTION INC. AND UNION GAS LIMITED

Answer to Interrogatory from
Building Owners and Managers Association ("BOMA")

MAADs Issues List – Issue No. 2

Reference: *Ibid, p43*

Question:
Please provide a list of the accounting changes which will be implemented as a result of the merger. Please discuss each likely change in detail, including the likely impact on Amalco's revenue requirement and customer rates.

Response

Please see the response Board Staff Interrogatory #31found at Exhibit C.STAFF.31.

ENBRIDGE GAS DISTRIBUTION INC. AND UNION GAS LIMITED

Answer to Interrogatory from
Building Owners and Managers Association ("BOMA")

MAADs Issues List – Issue No. 2

Reference: *Ibid, p29*

Question:
The evidence states that the combined customer care annual expenditure is $150 million.

(a) Please break that amount down by company, and by category of expenditure, so as to give a clear picture of customer care activities and their costs. Please include both OM&A and capital.

(b) Please define the scope of what are considered customer care expenditures in each company. Please identify any material differences.

(c) What is the customer care cost per customer for each of Union and EGD in 2016 and 2017, and (forecast) for 2018?

(d) The company states it intends to deliver customer care savings of $15 million (10% reduction to combined customer care expenditures in 2020-2023:
   (i) Please explain how the reduction ($4 customer care per customer will be achieved).
   (ii) Please confirm that the steps taken to achieve the level of savings in 2020, 2021, 2022 and 2023, including increasing the percentage of e-bill customers, increasing collection efficiencies and "work force adjustment", do not require material capital expenditures. Please explain each of the initiatives in detail, showing what savings are forecast per each year from each activity, eg. from increasing the percentage of e-bill customers by a forecast amount and savings per additional e-bill.
   (iii) Please confirm what level of capital expenditure in 2019, 2020, 2021 is required to achieve the $4 per customer reduction in 2020. In what year will Amalco realize its 10% target? Will any capex be required to reach this target? How much?
   (iv) Please advise the status of the planning for these changes since February 2017 (the EGD/Spectra acquisition closing date).
   (v) Please explain the increase in annual savings from $15 million to $26 million in 2024.
   (vi) Please account for the manner in which EGD customer care expenditures have been handled pursuant to the CIS Settlement Agreement over the last several years in setting the customer care baseline. The intent here is to set a "customer care baseline", and to explain the $150 million stated in evidence.

(vii) Please provide a detailed schedule for the integration of the customer care software program. Why is it necessary to integrate customer care operations to a single software system? What are the costs, benefits, risks in making this integration?
(viii) Please provide a detailed explanation of the proposed $65 million cost of implementing the software integration.
(ix) Please deal with the apparent inconsistency between the numbers in Attachment 12 and the range for the same task included in Table 4, which provides a range from $25 million to $110 million.
(x) The evidence is that the project time will take two to three years. What is the schedule for the implementation of the project capex planned for each year, and describe the components of the project plan to be accomplished in each year? Please provide a copy of the implementation plan.

Response

(a) The customer care annual expenditure of $150 million used in establishing the high level cost savings estimate represents an approximation of EGD's and Union's customer care annual costs. The estimate was not built up by cost category.

(b) Customer care expenditures include billing, call answering, collections, postage, and meter reading. At a very high level, a key difference between the two utilities' customer care services is that EGD outsources some of its customer care functions while maintaining ownership of the underlying customer care systems. Union in-sources most of its customer care services while leasing its underlying customer care system. As a result of this difference the Union customer care expenditures also include costs associated with web-based applications and billing systems while the EGD costs do not.

(c) Please see the response to VECC Interrogatory #9 found at Exhibit C.VECC.9.

(d) (i), (ii) (iii) (v) (vii) (viii) As described above, the company has not conducted any detailed integration planning. Attachment 1 provides the narrative of the high level cost estimates and savings planning undertaken for Management review/approval. Appendix B and C were created to respond to the many interrogatories relating to how the estimates were generated.

(d) (iv) (x) The company has not commenced any detailed planning on the integration of utility functions. The company will commence the detailed integration planning upon Management receiving approval of the amalgamation by the OEB, the EGD, Union and Enbridge Inc. Board of Directors.

(d) (vi) Please see response (a) above to understand the $150 million customer care amount used in high level integration planning. This estimate includes EGD's customer care expenditures.

(d) (ix) Attachment 12 provides the yearly profile and ten year totals of the estimated capital investment and potential O&M savings for each of five functional areas. Table 4 provides the range of potential capital investments and O&M savings that Management believes may arise depending on the outcome of the detailed integration planning and ultimately final execution of all integration activities. The ranges provided in Table 4 highlight the potential range of cost and savings outcomes as a result of underspending or overspending on capital investments and underachieving and overachieving on O&M savings.

Utility Integration Opportunities: Cost and Savings Assumptions

Utility Integration High Level Planning Process

To identify the potential integration opportunities, Management met jointly and reviewed the existing functional areas within each utility. This included a review of the historical financial operations, the key business process areas and supporting software and business systems. The review allowed Management to compare and contrast historical operational results and future forecasted results including: financial results for the prior 5 years, detailed results for the 2017 forecast and 2018 budget for the utilities Operations for Enbridge, and the long range strategic plan for the Utilities Operations for Enbridge.

Based on this review, the following key functional areas for integration were identified:

1) Customer Care,

2) Distribution Work Management,

3) Shared Services,

4) Storage & Transmission Operations and Gas Supply & Control,

5) Management and Other Functions (Engineering, Integrity, Public Affairs, Demand Side Management, Cap & Trade, Business Development).

Management has extensive expertise and knowledge of the operations of each utility and was able to draw on the results from previous operations reviews and business process improvement projects that have been implemented over the past 15 years for each utility under their respective Custom Incentive Regulation frameworks. The cost estimates included in the Utility Integration Plan are based on the known costs for each utility for both capital and operating expenses and forecasted expenditures. The 10 year Asset Management Plans for each of the utilities is the basis for the capital expenditures over the 10 year MAADs framework timeline.

Summary of O&M Savings and Related Capital Costs:

The following section details the assumptions underpinning the estimated cost efficiency opportunities for the integrated utility ("Amalco") in the five functional areas listed above.

The estimated savings and associated capital investment are summarized in Table 2 below and the annual impacts from 2019 to 2028 are provided in Appendix A. Field Operations have been excluded from the scope of the analysis at this time to ensure consistency of safe and reliable operations and to reflect that service areas for each utility do not directly overlap, though they will be adjacent in some areas.

The estimated capital investment required for integration of technology to support the integration of processes is between \$50 million and \$250 million to deliver potential net savings in operating costs of between $350 million and $750 million over the deferred rebasing period, depending on the level of integration and timing of investment.

Table 1

High Level Minimum and Maximum Cost and Savings Estimate

Item	Potential Capital Investment		Potential O&M Savings	
	Minimum	Maximum	Minimum	Maximum
Customer Service	$25 M	$110 M	$120 M	$250 M
Distribution Work Management	$10 M	$90 M	$30 M	$150 M
Shared Services	$ 5 M	$20 M	$15 M	$50 M
Storage & Transmission	$5 M	$10 M	$15 M	$50 M
Management Functions & Other	$5 M	$20 M	$170 M	$250 M
Total	$50 M	$250 M	$350 M	$750 M

While the groups and functional areas that will generate synergies have been identified, the detailed implementation plans will only be developed and implemented after a successful conclusion to the regulatory process. Many of the synergy opportunities are tied to the ability to eliminate duplicate systems and processes through the alignment of processes, procedures, standards and specifications. Whenever possible, the final Implementation Business Case will leverage existing processes, procedures and supporting software applications that are already in place to minimize costs and overall change impacts.

Risks

The highest perceived risk to achievement of the O&M synergies is the pace and number of concurrent changes within the organization. A dedicated and focused Project Management Office supported by external expert resources will ensure all work streams are aligned, risks are identified and mitigated. Throughout the implementation period, impacts to field operations will be carefully considered to ensure continued safe operations while the customer care stream will focus on implications and impacts to our 3.5 million customers.

Multiple Large Scale Software Implementations

Significant software system implementations will take place over the ten year deferred rebasing period from 2019 to 2028. Large scale system implementations will be staggered to allow for staff to be resourced to these projects and to support change management and adequate adoption of the new systems and processes by employees and vendors. The timing of these system implementations will also need to consider corporate Enterprise Resource Planning (ERP) system initiatives that will be happening concurrently throughout this period. The estimated cost efficiencies related to systems implementations is based on a moderate to aggressive timeline, as three large system implementations are projected to be completed by 2024.

The first large system implementation that will potentially affect the utility integration is the enterprise ERP migration. The second large system implementation is the Distribution Work Management system unification. The third large system implementation is the migration to one customer care software application. Each of these projects has a two to three year project duration and each large system implementation carries both timeline and cost risks. Management will ensure no-harm to the customer experience through these multiple system changes by balancing quality outcomes with cost and timeline risks. The utilities have recent experience with large software implementations including SAP, ConTrax, Oracle, SCADA and Maximo system implementations and will be supported by the Enbridge enterprise support teams and external expert resources as required.

Business Process Transformations

Integration of the utilities' business processes is generally expected to take place over the first six years. The breadth of this integration and the associated business process transformation is significant. To provide context for the breadth and potential complexity of the integration consider the following examples:

- Alignment of engineering policies including pipeline and facilities construction, inspection, maintenance and distribution operations, etc.
- Common processes for supply chain procurement.
- Alignment of safety policies and practices.
- Common work management processes including estimating, planning, scheduling, and execution practices and policies.

- Consistent accounting practices and policies including consolidated financial forecasting and reporting.
- Alignment of various management systems (asset, emergency response, safety, etc.)
- Alignment of the 10 year asset management plan including risk identification and mitigation practices.

In addition to the operational processes that will be integrated, one of the most significant undertakings will be to integrate the two utilities' customer care operations. A detailed review will identify the differences between the two utilities' methods and approaches and a plan will be developed to manage the transition accordingly. This integration of the customer care operations is forecasted to deliver savings five years after the legal amalgamation in 2019. The unification of the customer care service delivery models can only be accomplished with the implementation of a common customer care approach and related software support.

Given the inter-dependencies and the breadth of integration between systems and business transformation there is a risk to the moderate to aggressive timeline and therefore a ten year deferred rebasing was selected to provide sufficient time for Management to achieve a fully aligned and stabilized integrated utility prior to rebasing in 2029.

Capital Cost Assumptions

Customer Care

Currently the two utilities have different customer information software (CIS) applications and approaches. EGD utilizes SAP software to support its Customer Care activities that had an implementation cost of approximately $118 million and relies on Accenture as an outsource provider for some of the customer care functions. Union contracts with Vertex to use the Banner Customer Care system to support their internally delivered customer care operations. The integrated utility will unify customer care operations under a single CIS and supporting software platform. A detailed analysis will be completed to determine the best customer care solutions to deliver quality services to our customers. The range of solutions includes migration of Union data and business processes into the EGD SAP software, migration of EGD data and business processes to the Union platform, and implementation of a new system. The estimate of $65 million represents migration to one of the current existing software platforms and structures. The estimate is approximately 50% of the original EGD SAP software implementation costs.

Distribution Work Management

EGD completed an implementation of a new software platform (Maximo) to support work management systems in 2016 at an approximate cost of $85 million. The current software supporting the Union platform (Advantex) is nearing end of life and will not be supported in the near future. While a detailed analysis of options is required, the estimated cost efficiencies are based on integrating Union and EGD into a Maximo software system. Management estimates that a potential range of implementation costs could be between $30 million for data and business process migration to $85 million for full implementation. The estimate for migrating Union processes and data into Maximo is approximately $50 million.

Utility Shared Services

There are a number of Shared Services such as Finance, Human Resources, Information Technology, Supply Chain Management, Real Estate Services and Enterprise Safety & Operational Reliability that are resident at the utility and provide specific utility based shared services. Initiatives to align shared service functions across the enterprise are ongoing and are part of the overall corporate merger integration and not managed directly by the utilities.

There are smaller systems and software that are specific to the utility functions that reside in shared services. The initial review has identified applications such as: Utility contract management (EGD uses CMS and Union uses Ariba), utility billing financial analysis (EGD uses RAVE), IT service requests (EGD uses Service Now and Union uses an in-house system), real estate services (EGD uses Archibus and Union does not have a dedicated software application). This listing of utility software applications will be refined and then reviewed/rationalized against the overall Enbridge enterprise software pillars of Finance and Human Resources (Oracle and WorkDay) to determine the best package to meet the local utility functional requirements.

An initial preliminary estimate to implement a common software platform for those areas of shared services is set at $13 million. This cost estimate reflects implementation of between 5 to 10 systems resulting with an average implementation cost range of $2.6 million for 5 systems and $1.3 million for 10 systems.

Overall Management estimates that the range of costs for these shared services systems is between $5 million and $20 million.

Storage and Transmission Operations and Gas Supply and Control

Union's Storage and Transmission facilities are larger than that of EGD. Union has its SCADA system in Chatham and EGD has a distinct SCADA system in Edmonton. Union and EGD use different software applications for their Gas Supply settlement processes (UNION usesConTrax and other smaller systems and EGD uses OpenLink, EnCore and Entrac). A high level preliminary estimate to integrate the SCADA system and selection of software for gas supply operations to a common platform ranges from $5 million to $10 million. The midpoint of this cost range is approximately $8 million as an unclassified estimate.

Other Functions

With respect to Asset Management, EGD has progressed with its implementation of its Asset Management processes using the RIVA software. The RIVA software and associated processes provide capital business case entry, evaluation of engineering asset health and asset investment optimization. Management expects some small amount of costs to integrate Union and EGD into the single asset management processes and software given the system is standalone to the distribution work management software system.

Union and EGD have several systems that facilitate day-to-day operation of the utilities. Some of the different systems include: GIS, extranet websites, different meter-reading based software and several data warehouses that facilitate data analytics and reporting. Management plans to start the integration of these utility systems in 2019 and has preliminary initial cost estimates ranging from $5 million to $20 million. An average range of per system capital costs between $0.5 million and $2 million has been used to migrate or replace a range of 7 to 30 systems. (30 systems @ $0.5 million per system = $15 M) The unclassified estimate of $14 M has been used as a baseline capital cost estimate for the Other Functions/systems.

Net O&M Savings Assumptions

Customer Care

Management will start Customer Care integration efforts subsequent to an OEB decision on our MAADs integration application, evaluating the costs and benefits of the various alternatives and identifying the optimal solutions to implement common approaches and supporting software. As detailed above, EGD has outsourced customer care services while using internal software to support these services (SAP for Utilities). Union has insourced customer care services while using an external system to support the billing and related functions (Vertex's Banner software).

The two customer care groups have different operating practices. The principal metrics to evaluate the various options will be to ensure we are maintaining or improving customer service levels while lowering the total cost to provide customer service. Projected savings (prior to any system changes and alignment) have been based on a medium to aggressive schedule expectation with planning work starting in the later part of 2018 leading into the implementation of several changes starting in 2019. The goal is to target the delivery of the first tranche of savings in 2020 to 2023. Savings in this first tranche are targeted to realize a 10% reduction to the combined utilities' customer care services cost (estimated to be approximately $150 million in total. 10% * $150 million = $15 million). This reduction would equate to an estimated reduction of approximately $4 /customer across the combined 3.5 million customer base. These efficiencies could be the result of activities such as a digitization campaign to increase e-bill customers, increase collections efficiencies, optimize the workforce with one of either the Union or EGD model or a hybrid approach where some services are outsourced and others insourced.

A major long term contributor to achieving further efficiencies in the customer care function is the migration to a single CIS platform. Migration is currently targeted to be in-service by 2024. The unification onto a single software platform is expected to accompany the implementation of processes that enhance moving to the single software platform. The combination of moving to a single platform is expected to improve customer service offerings and reduce the workload required to process customer interactions and service. The expected total cost of operations for customer care services in 2024 is projected to be approximately $135 million per year ($150 million net of $15 million annual savings). Given efficiencies achieved in the first phase of the customer care business optimization plan (2020 to 2024), a goal to further optimize by an incremental 7.5% from the earlier 10% cost reduction is seen as aggressive but achievable. The incremental 7.5% can deliver an additional $10 million per year from 2024 to 2028. Overall, the targeted reduction in annual O&M costs by 2024 is approximately 17% below the 2018 forecasted level of $150 million. These reductions are to be achieved from a combination of increased number of e-bill customers through better customer care web services, migration to a single CIS platform and rationalization of processes to implement best practice and processes that accompany the customer care system which should support some reduction in duplicative workforce.

A key consideration for the delivery of customer care efficiency plan outcomes is execution and specifically the dependency on other system transformations that the Enbridge enterprise and the integrated utility will undertake. The Enbridge enterprise is undertaking a finance transformation which will implement a common ERP system at some point between 2019 and 2021. This timing will impact the ultimate timing and delivery of a unified customer care software system given this system is the "cash register" for the integrated utility revenues. In addition, timing of software migrations undertaken at the utility such as the work management system, gas supply and commercial marketer and transmission software systems will impact the delivery of the customer care integration plan. Finally, the scope and size of the software implementation is uncertain at this time given the current options for the final software and customer care approach. Table 2 highlights the cost and savings range uncertainty.

Distribution Work Management

Distribution work management is the planning, scheduling, compliance, work management systems (WMS), WMS support, asset management and support for overall work to maintain our assets and to plan and schedule work across both Union and EGD. There is an opportunity to eliminate redundancy of systems and improve worker efficiencies in the planning and scheduling of field work by adopting the best practices from both utilities and to consider which model will deliver the best outcome in terms of customer service and cost. Savings have been estimated at $11 million/year or 10% of the estimated 2016 costs ($110 million). The estimated savings increase to $16 million/year in 2024 to 2028 is due to optimizing 3rd party contracts.

EGD has recently implemented the Maximo software platform in conjunction with the eGIS software and Click Mobile software as its end-to-end distribution work management system. The Maximo platform is established as a solid base for future optimization of this business function. The primary area of integration focus for this business function is the back-office activities, integration with customer care services to improve offerings/delivery times to customers and software unification. The two companies have different approaches to how the distribution work management function is undertaken. An integration plan will be undertaken to evaluate each distribution work management process and to implement the best practice at the lowest cost. Given that both utilities have optimized workforces and optimized internal processes on a standalone basis and the integrated utility has forecasted approximately 50,000new customer additions per year, an estimate of 10% further reduction in costs and workforce planning is seen as moderate to aggressive.

Utility Shared Services

Utility Shared service functions at Enbridge include: Finance, Human Resources, Information Technology, Supply Chain Management, Real Estate Services and Enterprise Safety & Operational Reliability. The Enbridge corporate office functions began to integrate and optimize the combined Spectra and Enbridge shared services at the close of the merger in Q1, 2017. A significant consideration for Management in the corporate shared service integration plan is the distinctness of the utility function relative to other business units in the new Enbridge. The Utility Finance, Human Resources, Information Technology, Supply Chain Management, Real Estate Services and Enterprise Safety & Operational Reliability requirements will be addressed by Management by reviewing practices currently executed between the two utilities to determine the impact of implementing a range of harmonization and standardization within these.

The targeted savings are estimated to be 2% to 7% of the combined annual operating costs which equals approximately $2 million to $7million per year on an approximate base cost of $100 million for the integrated utility.

Storage and Transmission Operations and Gas Supply and Control

The Storage and Transmission Operations and Gas Supply business function include operations and maintenance of the transmission pipeline systems, storage wells and reservoirs. Gas Supply and Gas Control includes the gas control room operations for both EGD and Union, gas supply and upstream transportation contracting and settlement processes and associated systems and software for both utilities. There are some opportunities to apply best practices across the utilities and to determine if there are operational benefits available related to the combination of these assets. The integration and alignment of the SCADA systems will also yield a potential benefit. The primary cost savings is expected to come from harmonizing the SCADA systems to one, process changes to optimize maintenance costs and alignment of contracts. The savings are estimated to be an average of $3 million per year over the ten years or approximately 10% of the annual $30 million in cost.

Management Functions

There are opportunities to rationalize the Management structure and other functions within the integrated utility. Identifying a single Management structure and Executive Management Team is one of the first integration efforts that will be conducted. Broader workforce reductions are expected to occur at a much more gradual pace as various integration initiatives are undertaken over the 10 year deferred rebasing period. Considerations by the new Management team with respect to any workforce reductions will require a review and alignment of operational processes and the related systems, and the staff necessary to execute these processes so that safe, reliable business operations continue and service levels are maintained. The savings from the rationalizing of Management structure is estimated to be $180 million over ten years. While this equates to a 7% reduction in combined utility annual salaries and wages of $285 million (net of capitalization), this estimate for potential savings is considered aggressive as a percentage of the Management level salaries. The estimate for Management structure changes is input as $20 million per year with a first year severance cost of $20 million. The estimated $20 million cost reduction will come from a mix of people leadership levels at both utilities. Management used a 25% reduction to an estimated base of 450 combined leadership positions for the purpose of this analysis.

Other Functions

Other functions include business areas such as Engineering and Integrity, Information Technology, Public Affairs, Demand Side Management, Cap & Trade and other Low Carbon Business Development. These groups have opportunities to integrate and drive productivity associated with elimination of smaller software systems, implementing sourcing models to reduce internal system support costs, implementing efficiencies through vendor contract management and process optimization cost savings opportunities. The annual savings estimate from this area is approximately $14 million per year based on a 14% reduction to an annual combined O&M cost estimate of approximately $100 million. Given the majority of the savings will come from the rationalizing of Information Technology systems costs, the savings are expected to be generated in 2024 through 2028.

Appendix A: Capital Investment and High Level Estimated O&M Savings for Utility Integration

Integration Capital investment and O&M Savings Schedule ($ Millions)

Item	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	Total
Capex											
Customer Care		$ 2	$ 22	$ 32	$ 8	$ -	$ -	$ -	$ -	$ -	$ 65
Distribution work management	$ 7	$ 21	$ 21	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 50
Utility Shared Services	$ 4	$ 5	$ 5	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 13
Storage & transmission	$ -	$ 8	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 8
Other functions	$ -	$ -	$ 5	$ 5	$ 5	$ -	$ -	$ -	$ -	$ -	$ 14
Sub-Total Costs	$ 11	$ 36	$ 53	$ 37	$ 13	$ -	$ -	$ -	$ -	$ -	$ 150
O&M savings											
Customer Care	$ -	$ 15	$ 15	$ 16	$ 16	$ 26	$ 26	$ 26	$ 26	$ 26	$ 192
Distribution work management	$ -	$ -	$ 11	$ 11	$ 11	$ 16	$ 16	$ 16	$ 16	$ 16	$ 113
Utility Shared Services		$ 2	$ 2	$ 3	$ 3	$ 5	$ 5	$ 5	$ 5	$ 5	$ 35
Storage & transmission	$ -	$ 1	$ 3	$ 3	$ 3	$ 4	$ 4	$ 4	$ 4	$ 4	$ 30
Management	$ -	$ 20	$ 20	$ 20	$ 20	$ 20	$ 20	$ 20	$ 20	$ 20	$ 180
Other functions						$ 14	$ 14	$ 14	$ 14	$ 14	$ 70
Sub-Total Savings	$ -	$ 38	$ 51	$ 53	$ 53	$ 85	$ 85	$ 85	$ 85	$ 85	$ 620
Additional unidentified efficiencies	$ 3	$ -	$ 12	$ 17	$ 28	$ -	$ -	$ -	$ -	$ -	$ 60
Sub-Total Savings	$ 3	$ 38	$ 63	$ 70	$ 81	$ 85	$ 85	$ 85	$ 85	$ 85	$ 680

Appendix B: High Level Estimated Capital Investment and O&M Savings Assumptions Summary

The following table provides a summary of the assumptions that underpin the estimated capital investment and net O&M savings for each key functional area as well as the assumptions used to establish the high level mininum and maximum cost and savings estimates found in Table 2 above.

Item	Capital Investment Assumption Summary	Net O&M Savings Assumptions Summary
Customer Service	Used EGD SAP software system implementation cost of $118 million as base to evaluate range of potential costs to integrate Union Gas and EGD customer service software. Range of possibilities include: a. Data migration of Union Gas into existing EGD software with a minor amount of system changes. High level cost estimate of this scenario is contemplated as approximately 20% of base cost of $118 million or $25 million. b. Full Implementation of software and system changes. High level cost estimate contemplated as just below the full cost of the EGD SAP implementation given potential cost efficiencies have been achieved since EGD SAP implementation ($110 million) With the range of potential costs being between $25 million and $110 million, an assumption of $65 million, or a value of just over half of the maximum end of the range was used as the basis for the customer service capital investment.	Used an assumption that the combined total O&M cost of approximately $150 million per year. Used a medium to aggressive integration project schedule with the expectation that planning work starting in the later part of 2018 leading into the implementation of several changes starting in 2020. First tranche of savings in 2020 to 2023: • Savings in this first tranche are targeted to realize a 10% reduction to the estimated combined utilities customer care services cost of $150 million. (10% x $150 million = $15 million per year). As a reasonableness check of the 10% target of reduction in costs, a comparison was made to the equivalent cost per customer reduction. An annual $15 million reduction would equate to an estimated reduction of approximately $4 per customer across the combined 3.5 million customer base. Second tranche of savings from 2024 sustained through to 2028: • The expected total cost of operations for

Item	Capital Investment Assumption Summary	Net O&M Savings Assumptions Summary
		customer care services in 2024 is projected to be reduced from the assumed $150 million by the $15 million of annual savings in the first tranche of integration. • Savings in the second tranche will require an aggressive plan to achieve significant incremental savings. • A goal was set to achieve an incremental 7.5% cost reduction in addition to the first tranche cost reduction of 10% as the second tranche annual percentage savings assumption. • The reduction in annual O&M costs from 2024 onward, as a result of an annual savings of approximately 17% below the level of $150 million equates to $26 million per year in annual savings. The cumulative savings from the first and second tranche of customer service integration equals a total cost reduction of approximately $192 million or a ten year average of $19 million per year. The minimum cost savings was established as two-thirds of the base ten year average or approximately $12 million per year or $120 million over ten years. The minimum cost savings assumes that the aggressive 10% and sustainable 17% annual savings percentages are not achieved. The maximum cost savings was estimated as an achievement of an incremental one-third cost reduction in addition to the base ten year average. Assuming integration activities exceed the base ten year average

Item	Capital Investment Assumption Summary	Net O&M Savings Assumptions Summary
		cost reduction by one-third, the ten year average cost reduction will result in total maximum savings of $250 million or an average of $25 million per year over ten years.
Distribution Work Management	Used EGD Maximo software system implementation cost of approximately $85 million as base to evaluate range of potential costs to integrate Union Gas and EGD distribution work management software. Range of possibilities include: a. Data migration of Union Gas into existing EGD software with a minor amount of system changes. The cost estimate of this scenario was contemplated as approximately 10% of base cost, or $10 million, based on an assumption that data migration will mean lesser overall project complexity and cost. b. Full Implementation of software and system changes. High level cost estimate contemplated this scenario as being equivalent to the recently completed EGD Maximo implementation ($90 million) With the range of potential costs being between $10 million and $90 million, an assumption of $50 million was established as the base capital investment for the distribution work management integration, or a value of just over half of the maximum end of the range. An assumption that a capital investment scope that would fall between the minimum and maximum project estimated scopes was deemed a reasonable base scenario.	Used an assumption that the combined total cost of distribution work management is approximately $110 million per year. Used an assumption of a medium to aggressive integration project schedule with the expectation that planning work starting in the later part of 2018 leading into the implementation of several changes starting in 2021. First tranche of savings in 2021 to 2023: • Savings have been estimated at $11 million per year or 10% of the estimated total combined distribution work management O&M costs of $110 million. Second tranche of savings from 2024 sustained through to 2028: • Assumed a second tranche of cost reduction based on optimizing 3rd party contracts, field operations and business process optimization. • Used a goal of achieving 16% cost reduction to the base total combined distribution work management O&M costs of $110 million. The 16% equates to annual cost reduction of approximately $16 million per year.

Item	Capital Investment Assumption Summary	Net O&M Savings Assumptions Summary
		The total savings over ten years from the first tranche and second tranche of estimated distribution work management integration equals approximately $113 million or a ten year average of $11 million per year. The minimum cost savings was established as one-third of the base ten year average or approximately $11 million per year ($30 million over ten years). The minimum cost savings assumes that the aggressive 10% and sustainable 16% annual savings percentages are not achieved. The maximum cost savings was estimated as achieving an incremental one-third cost reduction to the base ten year average. Increasing the $11 million cost reduction by one-third equates to an estimated total maximum savings of $150 million or an average of $15 million per year over ten years.
Utility Shared Services	This estimate is intended to approximate a reasonable cost for integration of several smaller utility shared service groups systems. A number of 15 smaller system integration projects were used as the basis of the estimate. Used approximations of smaller software/ system implementation cost ranges as a base to estimate the range of potential costs to integrate Union Gas and EGD utility shared service groups. Assumed that 5 systems would be implemented at an average of $2.6 million per system and 10 systems would be implemented at $1.3 million. The total cost from this assumption was then halved for purposes of this high level estimate (5 x $2.6 million + 10 x $1.3 million = $26 million/2 = $13 million).	Used an assumption that the combined total cost of utility shared service departmental costs is approximately $100 million per year. Used an assumption of a medium to aggressive integration project schedule with the expectation that work starts in the later part of 2018 leading into the implementation of several changes starting in 2020. First tranche of savings in 2021 to 2023: • The first tranche is to conduct systems integration projects to implement technology and process efficiencies. • Savings have been estimated at $2 to $3 million per year or 2% to 3% of the estimated total O&M costs of $100 million. • Assumption of annual percentage savings being

Item	Capital Investment Assumption Summary	Net O&M Savings Assumptions Summary
	To determine a range of low and high cost estimates, the $13 million was used as the basis of the utility shared services capital investment. This $13 million was decreased by one-third of its value to estimate the minimum capital investment and the base was increased by one-third of its value and rounded up to estimate the maximum capital investment.	2% and 3% respectively recognizes that the utilities have implemented efficiencies to their local utility shared service groups and therefore, have opportunities stemming from smaller systems and process improvements. Second tranche of savings from 2024 sustained through to 2028: • The second tranche of integration activities are expected to coincide with the stabilization of capital investments in the utility shared services systems and set out a target to achieve incremental savings of 2% to 3% in addition to those estimated in the first tranche of integration. • The second tranche assumption is a target achieving a 5% reduction in the total cost of utility shared services. The incremental 2% to 3% of cost reduction is assumed as a stretch goal and believed achievable through the pursuit of further process and contract efficiencies.
Storage & Transmission	Used an approximation of $5 million to $10 million range as cost estimate to represent contemplation of costs to migrate to one SCADA system and integrate two software systems. Upper cost estimate of $10 million assumed $8 million to integrate SCADA and two software integrations of $1 million each. To determine the minimum capital investment, an assumption of half of the maximum capital investment estimate was used. With the range of potential costs being between $5	Used an assumption that the combined total cost of storage and transmission O&M is approximately $30 million per year. Used an assumption of a medium to aggressive integration project schedule with the expectation that work starts in the later part of 2018 leading into the implementation of several changes starting in 2020. Assumed cost savings are expected to come from harmonizing the SCADA systems to one, process changes to optimize maintenance costs and alignment of contracts.

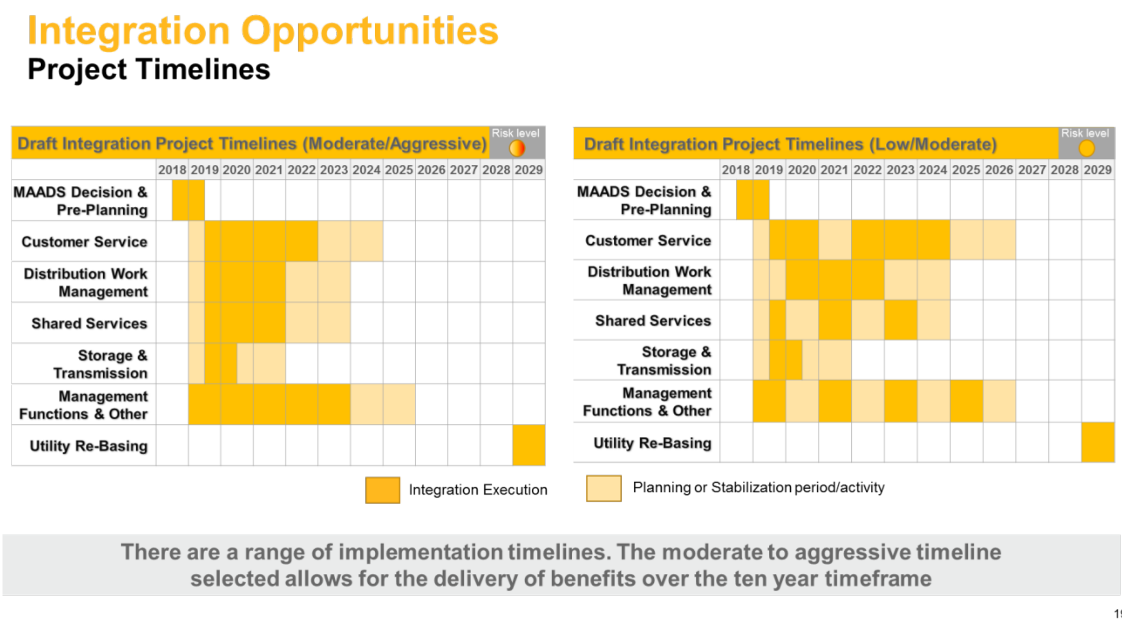
Item	Capital Investment Assumption Summary	Net O&M Savings Assumptions Summary
	million and $10 million, an assumption of $8 million, the rounded up amount of the midpoint between $5 million and $10 million was used as the basis for the storage and transmission capital investment.	Used an estimate of an annualized 10% cost reduction to the estimated total O&M of $30 million per year to establish an estimate of average annual cost savings. Assumed a stretch target of achieving the average annual cost savings estimate of $3 million per year, over the ten year deferred rebasing period or the equivalent of $30 million of savings. The expectation is that savings will likely commence in 2020 post completion of the capital investment for storage and transmission. Based on the assumption and target to achieve $30 million of savings over the ten year deferred rebasing term, the estimated savings were profiled in a graduated manner over the years of 2020 to 2028.
Management Functions & Other	There are no planned capital investments with the Management Functions functional area. This integration opportunity represents the establishment of the integrated utilities management structure. The Other Functions functional area represents a high level cost estimate to integrate the many smaller scoped software systems that are used by both utilities. A cost assumption range of between $0.5 million cost per system integration to $2 million cost per system integration was considered to be a reasonable approximation of the potential costs to integrate the systems used in these functional areas. Assumed 30 system integration projects with an average cost of $0.5 million per project to establish a base of $15 million capital investment.	<u>Management Functions:</u> Assumed an average per management function salary and wages, short term and long term incentive plan cost reduction of $*175 Thousand*. Estimated a reduction of 25% of the Management base of 450 combined leadership positions resulting in an annual cost reduction estimate of approximately $20 million per year. Assumed severance costs equivalent to the estimated savings of $20 million being incurred in the first year when the management structure change is implemented. The estimated savings from the rationalizing of Management structure is estimated to be $180 million

Item	Capital Investment Assumption Summary	Net O&M Savings Assumptions Summary
	To determine a range of minimum cost estimates, the base of $15 million was decreased to one-third of its value or $5 million. The maximum cost estimate was established by increasing the base of $15 million by one-third to $20 million.	over ten years. The estimated $20 million annual savings equates to a 7% reduction in combined utility annual salaries and wages of approximately $285 million (net of capitalization), this estimate for potential savings is considered aggressive as a percentage of the Management level salaries. <u>Other Functions:</u> Used an assumption that the combined total cost of Other Functions O&M is approximately $100 million per year. Assumed Other Functions capital investment and potential O&M savings will be a second tranche integration set of activities. Pursuit of efficiencies in these areas will begin after primary (larger opportunity) areas have stabilized. Used an assumption of a medium to aggressive integration project schedule with the expectation that planning work starting in the later part of 2020 leading into the implementation of several changes and savings starting in 2024. Assumed an aggressive estimate of 14% cost reduction per year which is to be achieved by the elimination of smaller software systems, implementing sourcing models to reduce internal system support costs, implementing efficiencies through vendor contract management and process optimization cost savings opportunities. The annual savings estimate from this area is approximately $14 million per year on an annual

Item	Capital Investment Assumption Summary	Net O&M Savings Assumptions Summary
		combined O&M cost estimate of approximately $100 million. Given the majority of the savings will come from the rationalizing of Information Technology systems costs, the savings are expected to be generated in 2024 through 2028.

Appendix C: High Level Integration Project Timelines Assumption Summary

Management provides the following narrative and graph as further context to the high level integration cost and savings estimates. Graph 1 below shows two project Gantt charts that represent potential project timelines setting out the utility integration planning, integration execution and post in-service stabilization periods.



Graph 1 – Draft Integration Project Timeline Illustrations

The graph on the left, labeled Draft Integration Project Timelines (Moderate/Aggressive) shows one potential project schedule that has integration activities being conducted in parallel over the first five years of the deferred rebasing period. Planning for these activities would take place in the early half of 2019 followed by execution of capital investment projects with estimated in-service dates in 2021, 2022 or 2023. After these projects have been put in-service, there are stabilization periods of one to two years for each of the functional areas streams. The stabilization periods will allow for the project warranty periods to be completed and any residual issues to be remediated prior to resuming regular operations. This draft project timeline is the aggressive end of the project timeline spectrum, where the utility undertakes an aggressive and potentially higher risk exercise to complete all estimated integration activities as early as possible.

The graph on the right, labeled Draft Integration Project Timelines (Low/Moderate) shows a second potential project schedule that has integration activities being conducted in a staggered schedule over the first seven years of the deferred rebasing period. Planning for these activities would take place prior to the commencement of the initiative and different from the graph on the left, a period for stabilization and planning prior to commencing the next initiative would be introduced after the initiative was put in-service. The customer service functional area line in the graph on the right depicts the planning and commencement of a first phase of integration activities in 2019 and 2020 after which there is a year of stabilization and planning for the second phase of customer integration which would be conducted over the years 2022 to 2024. In this low to moderate draft project timeline the first phase of the customer service integration would be the integration to one customer service system and the second phase could be a project to implement a single customer service operations. No analysis or scenario planning was performed with respect to the low to moderate project timeline given the high level nature of this planning.

The graph on the right, the low to moderate project implementation schedule has the integration project schedule completing the capital investments in the eighth year of the deferred rebasing term or January of 2027.

The moderate to aggressive graph (Graph 1 left graph) when compared to the low to moderate graph (Graph 1 right graph) provides an understanding of one time duration difference that is required to complete the utility integration, stabilize and return to regular operations. The time range extends from six years under the accelerated project timeline to eight plus years under the more staggered execution project timeline. These are two potential project timelines and given the number and size of integration initiatives being undertaken over the ten year period, Management sees the ten year deferral of rebasing as a key incentive to achieve the full potential of integration activities in a balanced manner that delivers quality within a reasonably paced timeline.

ENBRIDGE GAS DISTRIBUTION INC. AND UNION GAS LIMITED

Answer to Interrogatory from
Building Owners and Managers Association ("BOMA")

MAADs Issues List – Issue No. 2

Reference: Table 4, p26

Question:

(a) What is the reason for the very wide range of forecasts for customer care capital expenditures (from $25 million to $110 million) – a range of more than 400% over the period 2019-2028, and the very large range in forecast savings (from $120 million to $250 million)? Should the number be superseded by the estimates in Attachment 12, or are these ranges still operative?

(b) Please provide a more realistic forecast of the amount or range for both capital expenditures and savings.

(c) Assuming that there is no deferred rebasing period, please explain how the applicants will ensure that the customers are not exposed to additional risk that will outweigh the benefits of the integration of the software.

(d) What precautions in legal contract development will be used to ensure cost control of the project, in light of the lack of cost control in EGD's first customer care software installment some years ago (which led eventually to the CIS Settlement several years later)?

(e) Would EGD be agreeable to capping the costs of the software integration program for rate-making purposes? At what level? Please discuss.

(f) Please provide the same analysis as described in section 16, above, for each of the other areas of operation in Table 4, not covered elsewhere in these Interrogatories, namely Utility Shared Services, and Storage and Transmission. Please discuss in detail. Given that EGD and Union personnel have been able to discuss and plan their transition to unified operations for more than a year, BOMA expects the answer can be provided in some detail. BOMA also understands that at least for some activities of the companies, very extensive discussions have already taken place.

Response

a) Please see the response to BOMA Interrogatory #16d), found at C.BOMA.16.

b) There is no additional or newer forecast information on integration activity costs or potential savings.

c) If there is no deferred rebasing period, then it is unlikely EGD and Union will amalgamate; if the utilities do not amalgamate, then it is unlikely that they would seek to integrate their CIS system software because the risks and complexities diminish the potential net benefits. In this scenario EGD and Union would continue operating as affiliates and would need to put in place additional intercompany service agreements to monitor and record cost transfers between the utilities and determine the appropriate methods to protect customer information and privacy requirements while being compliant with the Gas Distribution Access Rules ("GDAR") and Affiliate Relationship Code ("ARC"). These additional steps will add cost and complexity and be necessary to mitigate the additional risk and given the continuing operations of Union and EGD as affiliates, more than likely result in an outcome that will not achieve the full potential of benefits.

d) No detailed integration plans have been developed. The Applicants will not develop a detailed integration legal and procurement strategy until they have fully considered the OEB's decision on the Applications.

e) EGD and Union Gas do not agree to a capping of the costs of the software integration program. Under the MAADs policy, utility integration costs are borne by the shareholder throughout the deferred rebasing period and not included for rate-making purposes. EGD and Union have accepted that the utilities are at risk for the costs of the software integration.

f) Please see the attachment to BOMA Interrogatory #16i), found at C.BOMA.16 for information on the high level planning conducted in all other functional areas.

ENBRIDGE GAS DISTRIBUTION INC. AND UNION GAS LIMITED

Answer to Interrogatory from
Building Owners and Managers Association ("BOMA")

MAADs Issues List – Issue No. 2

Reference: Distribution Work System, p32

Question:
Please provide the current net capital cost of the Maximo software platform in the EGD rate base, and the current maintenance/sustainment costs for the software. Are the latter capitalized in OM&A? Please describe and provide the cost of any comparable work management system in Union. Please provide a "baseline" distribution work system cost for Union and EGD.

Response

The net capital amount of the Work and Asset Management ("WAMS") asset that is in EGD rate base and included in 2018 Rates is $53.7 million. The net capital amount of the WAMS asset is $76.7 million in the 2018 budget. The net capital difference between the budgeted amount for 2018which is not included in 2018 Rates and therefore not earning a return is $23 million.

The maintenance and sustainment costs for the WAMS asset are approximately $1.6 million in labour and approximately $3.3 million for software maintenance and support at the end of 2017. All of these costs are expensed and not capitalized.

Please see the response to BOMA Interrogatory #19(a) found at Exhibit C.BOMA.19 for context on Union's work management system.

Please see the response at BOMA Interrogatory #16(d) part (i) found at Exhibit C.BOMA.16 to understand the high level cost estimates used as part of the integration planning of the distribution work system.

ENBRIDGE GAS DISTRIBUTION INC. AND UNION GAS LIMITED

Answer to Interrogatory from
Building Owners and Managers Association ("BOMA")

MAADs Issues List – Issue No. 2

Reference: *Ibid, p32*

Question:

a) Please explain the various tasks that are included in the Distribution Work System project, as described on p32 and the concomitant costs.

b) What is the $30 million for "data and business practice migration", and $85 million for full implementation? What tasks are included in "full implementation" other than data migration?

c) Please explain the "second estimate" for data migration and process in the next line, at $50 million. Why are these two separate?

d) Please show how these estimates are consistent (or not) with the minimum capex shown on line 2, column 1 of Table 4 for Distribution Work Management.

e) Please provide an estimate for the project, broken down by tasks, in detail, which, inter alia, shows the capex forecast in each year, the amount of work that is being contracted out to various contractors, versus how much is being done internally, by Amalco personnel. Is all the internal work capitalized? If not, please provide the OM&A required.

f) Has the EGD transformation to a new work system management already begun?

g) When do the initial forecast savings of $11 million per year in work management system begin? Why do the savings increase to $16 million per year in 2026? What do these savings consist of – compensation, royalties, or other? Please specify.

h) How are the claimed savings measured against the baseline? What is the current combined cost of distribution work management, which would form a baseline for the measurement of the claimed savings?

i) Please provide a breakdown of and support for the proposed $11 million annual savings, and the $16 million annual savings.

j) Is the proposed 10% further reduction costs and work force planning incremental to the savings discussed above? Please discuss what is meant by moderate to aggressive. Please show consistency of the savings estimate with Table 4 savings estimate.

Response

a) The Distribution Work Management system project is required to replace Advantex[1] automated planning and dispatch system used to plan and manage Utility Services work at Union. Advantex is at end of life. Advantex will be replaced with the Maximo and Click software platforms currently used by EGD. Union will leverage the work already completed by EGD to minimize the amount of work required and align the systems to facilitate future possible integration. The specific work includes designing and implementing the Maximo and Click systems, interfacing those systems to other key systems at Union including the Banner and GIS systems, rewriting the associated business processes to align to the new systems, and training our field staff on the use of the new system.

b) The $30 million to $85 million is the range of costs associated with the implementation of the Distribution Work Management system.

c) The $50 million represented an early estimate of what is would cost to implement the Distribution Work Management system. Since the evidence was submitted, a more detailed estimate was developed. The current estimate is $55 million.

d) See answers to b) and c).

e) Please see Attachment 1.

f) Yes, the systems were put in-service in 2016 and the project completed in 2017.

g- j) Please see the response to BOMA Interrogatory#16(d) found at Exhibit C.BOMA.16.

[1] The vendor has renamed the application Service Suite.

Distribution Work Management Systems Implementation
Cost Detail - March 12th, 2018

Capital	Planning	Design	Build / Test	Implement	Warranty / Close		
Systems Consultants							
Diabsolut	$0.5 M	$1.4 M	$3.1 M	$1.3 M	$1.0 M		
Interloc	0.7 M	3.1 M	4.8 M	1.4 M	0.8 M		
Amalco Resources							
UG / EGD	2.2 M	5.3 M	8.1 M	3.0 M	1.2 M		
PMO Consultants							
E&Y	0.7 M	0.9 M	1.6 M	0.7 M	0.2 M		
Other							
Software	1.1 M						
Integrations / Environments		0.4 M	6.0 M				
Contingency			4.0 M				
Other		0.2 M	0.5 M				
Phase Total	$5.2 M	$11.3 M	$28.1 M	$6.4 M	$3.2 M	$55.0 M	**Project Total**

O&M	Planning	Design	Build / Test	Implement	Warranty / Close		
Amalco Resources							
UG				$1.0 M			
Phase Total	$0.0 M	$0.0 M	$0.0 M	$1.0 M	$0.0 M	$1.0 M	**Project Total**

ENBRIDGE GAS DISTRIBUTION INC. AND UNION GAS LIMITED

Answer to Interrogatory from
Building Owners and Managers Association ("BOMA")

MAADs Issues List – Issue No. 2

Reference: *Ibid, p33*

Question:
Given that both EGD and Union have "optimized workforces and optimized internal processes on a stand-alone basis", and given that their systems are mainly internal and not customer-facing, and given EGD's very recent and very large expenditure to create the Maximo system, is it necessary or prudent for EGD to embark on such a costly process to "integrate" the two systems? Please explain fully.

Response

Please see the response BOMA Interrogatory #3(b) found at Exhibit C.BOMA.3.

ENBRIDGE GAS DISTRIBUTION INC. AND UNION GAS LIMITED

Answer to Interrogatory from
Building Owners and Managers Association ("BOMA")

MAADs Issues List – Issue No. 2

Reference: *Ibid, p36-37*

Question:

(a) Please provide the justification for forecast savings of $180 million over ten years. What will the estimated annual savings be for each year from 2019 to 2028? How were these savings calculated? Which components of compensation were included? Are the savings all cash savings, or are they forgone increases? Please discuss fully.

(b) What is the baseline for which the proposed savings are calculated? Please provide the amount of total management compensation at the two companies that provides the baseline for the calculation of the savings shown in the Table (and Attachment 11). Please explain fully.

(c) Has the new management team been selected? When will it be announced?

(d) Does the capex range ($5 million to $20 million) on Table 4 for "Management Function and Other" entirely consist of severance payments? If not, what else is included in the forecast capex range? Why is the range so wide? How many individuals will receive severance payments or equivalent payments due to losing their jobs as a result of the merger? Please provide a more realistic and current estimate than wide range provided. Please discuss. How does the information presented in Table 4 square with the information provided in Attachment 11?

(e) What does the "Other" item in Table 4 refer to? Please specify what the capital expenditures and savings are. Please provide a description of each project/savings included in "Other".

Response

a) Please see the attachment identified in the response to BOMA Interrogatory #16(d) part (i) found at Exhibit C.BOMA.16 for further context on the Management Function $180 million high level forecast of savings.

b) Please see the attachment identified in the response to BOMA Interrogatory #16(d) part (i) found at Exhibit C.BOMA.16 for context on the Management Function forecast of savings.

c) No, a management team has not been selected. The selection of the management team will happen after Union and EGD receive approval to amalgamate.

d) Please see the attachment identified in the response to BOMA Interrogatory #16(d) part (i) found at Exhibit C.BOMA.16 for further on the Management Function forecast of savings.

e) Please see the attachment identified in the response to BOMA Interrogatory #16(d) part (i) found at Exhibit C.BOMA.16 for context on the Other Function forecast of savings.

ENBRIDGE GAS DISTRIBUTION INC. AND UNION GAS LIMITED

Answer to Interrogatory from
Building Owners and Managers Association ("BOMA")

MAADs Issues List – Issue No. 2

Reference: Exhibit B, Tab 1, Attachment 11

Question:

(a) Please describe how each of the pro forma statements were assembled on a step by step basis. Are the statements Amalco corporate statements or regulated Amalco company statements?
(b) Please confirm that the pro forma shown will be for calendar year 2019.
(c) Please provide comparable statements for each of the next four years.
(d) Please explain the "$825 million investment in affiliate" item. Please explain the detailed components of the regulatory assets and regulatory liabilities.
(e) Please explain the components of the "deferred revenue taxes item". Please explain the components of the capital expenditures and the proposed $103 million.

Response

(a) The pro forma statements shown are the Amalco corporate statements.

Step 1: Consistency of statement elements: The different elements of the information included in the pro forma statements were first aligned between Union and EGD.

Step 2: Revenues: for each utility were determined separately. Revenues are based on 2018 budgeted revenues, inflated by the forecasted price cap. Incremental revenue for 2019 capital investments was added (normal in-franchise growth, plus rate adjustments from capital investments in excess of the ICM threshold).

Step 3: Costs: for each utility were determined separately.

Step 4: Inter-company transactions: were eliminated to avoid double counting.
Step 5: Synergies: Costs to achieve and savings were then layered on at the Amalco level.

Step 6: Final Proforma Statements: The information was then presented in a format consistent with what is used for external reporting purposes.

(b) The pro forma statements shown in Exhibit B, Tab 1, Attachment 11, pages 2 to 4 are for calendar year 2019.

(c) Please see the response to BOMA Interrogatory #13(b) found at Exhibit C.BOMA.13.

(d) The investment in affiliate relates to the EBO 179-16 OEB approved non-utility EGD $825 million preferred securities investment in Interprovincial Pipe Line System Inc.

The components of Regulatory Assets & Liabilities include items recognized as a result of rate regulation, including: Gas Cost/Purchase Gas Variance/Deferrals, Non-Gas related deferred assets/liabilities, Asset Removal/Site Restoration costs, Deferred Income Taxes receivables, and Pension and OPEB receivables. Please see Note 2 of Union's 2017 Annual Report and Note 5 of the EGD 2017 Financial Statements as per Energy Probe Interrogatory #18 found at Exhibit C.EP.18.

(e) The deferred Income taxes on Exhibit B, Tab 1, Attachment 11, page 4 result from a timing difference in income recognition for accounting and tax purposes, respectively. They are primarily due to Net book Value (NBV)/ Undepreciated Capital Cost (UCC) differences in the unregulated activities of the Company (Amalco)

The breakdown of capital expenditure is as follows:

	$MM
Growth	742
Maintenance /IT	558
Cost of retirement	**50**
Total	**1,350**

The net cash provided by financing activities is made up of the following components:

Financing Activities	**$MM**
Net increase/(decrease) in short-term borrowings (including commercial paper)	258
Common shares issued (including paid in capital)	500
Long-term debt issued	600
Dividends paid	(655)
Net cash provided by financing activities	**103**

ENBRIDGE GAS DISTRIBUTION INC. AND UNION GAS LIMITED

Answer to Interrogatory from
Building Owners and Managers Association ("BOMA")

MAADs Issues List – Issue No. 2

Reference: Exhibit B, Tab 1, Attachment 12

Question:

(a) Please provide a discounted cash flow analysis of the aggregate expenditures and savings shown in Attachment 12, discounted at current interest rate, say 3.5%.

(b) Please provide a similar discounted cash flow analysis for each line of the table, i.e. Customer Care (capital vs. savings), etc.

(c) How do the capex numbers (totals) reconcile with the ranges in Table 4? Are they updates to the ranges shown on Table 4, based on more current information? Please explain fully.

(d) Please provide a rationale for including "unidentified efficiencies" of $12 million in 2021, $17 million in 2022, and $28 million in 2023, in the Table on Attachment 12. What do those substantial numbers represent? Please provide details.

(e) Given that over a five-year deferred rebasing period, Amalco would reap an estimated $257 million in savings from a capital investment over the same period of $150 million, which is a return of its original capital plus a profit of $107 million, why does it ask for a deferred rebasing period of ten years, rather than five years? Please provide an NPV analysis on the two streams of revenue shown in the Table, the total capex over ten years, and the total savings over the same period. What is the NPV ratio?

Response

a- b) The Applicants will not provide the requested line by line discounted cash flow analysis. The Applicants undertook a high level approach to integration planning to establish a preliminary cost and savings estimate. The request to provide line item discounted cash flow analysis of amounts that do not represent the costs derived from a detailed review will not provide any greater understanding of the high level planning performed to date or Management's commitment to bear significant integration related capital investment over the ten year deferred rebasing period.

(c) Please see the response to BOMA Interrogatory #16(d) part (ix) found at Exhibit C.BOMA.16

(d) Over the course of 10 years, Amalco will achieve only on average 20 bps above the forecast allowed ROE. Please see slide 23 of the presentation provided in the response to FRPO Interrogatory #1 found at Exhibit C.FRPO.1, Attachment 1.

The “unidentified efficiencies” in the Table on Attachment 12 represent additional savings that Amalco will need to find in those specific years so that Amalco will achieve a Return on Equity (ROE) that approximately equals the forecasted allowed ROE for that year. The unidentified efficiencies were included to recognize that all efficiencies cannot be identified today with precision and Amalco will need to undertake additional efforts and related savings to those estimated in Attachment 12 in order for the utility to achieve that year’s forecasted allowed ROE.

In the years 2021, 2022 and 2023, revenues are escalated at the assumed inflation factor of 1.73% under the Price Cap method proposed by the Applicants. The revenue escalation in these three years is not sufficient to cover the costs associated with the integration capital investment. The inclusion of these unidentified efficiencies highlights that the utility will not easily generate sufficient savings to offset the capital investment borne by the shareholder.

(e) Since no detailed integration plans have been developed, there are significant risks related to both timing and amounts. Please see the response to Board Staff Interrogatory #4 found at Exhibit C.STAFF.4.

ENBRIDGE GAS DISTRIBUTION INC. AND UNION GAS LIMITED

Answer to Interrogatory from
Building Owners and Managers Association ("BOMA")

MAADs Issues List – Issue No. 2

Reference: Exhibit B, Tab 1, p26, Table 4

Question:
For each of the four combinations of costs and savings estimates of Table 4, minimum investment/minimum savings, minimum investment/maximum savings, maximum investment/minimum savings, maximum investment/maximum savings, show the cash outflows and inflows pre-tax over the proposed ten-year rebasing period. Please provide a net present value (discounted cash flow) savings calculation for each of the four cases.

Response

Table 4 shows a high level estimate of potential minimum and maximum capital investment costs and O&M synergy savings, which do not have any adjacent projections of timing as to when such estimates may be incurred and/or achieved.

ENBRIDGE GAS DISTRIBUTION INC. AND UNION GAS LIMITED

Answer to Interrogatory from
Building Owners and Managers Association ("BOMA")

Rate Setting Issues List – Issue No. 1

Reference: Application p22; Exhibit B, Tab 1, p5 of 31

Question:

(a) Please explain why the "incremental cost of capital" should be used to calculate the revenue requirement to fund the ICM capital investment, given that all of the company's cash flow is fungible and is available to fund all of its capital expenditures and that the ICM may include high priority, eg. system access and system service investments that should properly be part of the company's base capital budget.

(b) Please define what is meant by the company's "incremental cost of capital". Please provide a full definition and explanation, for example, please identify what the capital referred to is incremental to, and how does it differ from other capital.

Response

a-b) Please see the response to Board Staff Interrogatory #14 found at Exhibit C.STAFF.14.

ENBRIDGE GAS DISTRIBUTION INC. AND UNION GAS LIMITED

Answer to Interrogatory from
Building Owners and Managers Association ("BOMA")

Rate Setting Issues List – Issue No. 1

Reference: Exhibit B, Tab 1, p3 of 31

Question:
Please confirm that the sentence at line 17, which states that the industry productivity factor is zero, quoted from EB-2010-0379 Report of the Board, Rate-Setting Parameters and Benchmarking under the Renewed Regulatory Framework for Ontario's Electricity Distributors, refers only to the electricity industry, and not the natural gas distribution industry. If you disagree, please provide justification and evidence on what the industry specific productivity factor for the natural gas distribution industry is.

Response

Confirmed. The evidence supporting the request for an X factor of zero and no stretch factor is provided at Exhibit B, Tab 2.

ENBRIDGE GAS DISTRIBUTION INC. AND UNION GAS LIMITED

Answer to Interrogatory from
Building Owners and Managers Association ("BOMA")

Rate Setting Issues List – Issue No. 1

Reference: Issue 1, p9

Question:
Please explain fully on what basis does Union expect higher than historical and existing cost pressures from line locations, increased system access projects, and "depreciation increase even when managing maintenance capital expenditures to this level of depreciation" (our emphasis)..

Response

Please see the response FRPO Interrogatory #18 found at Exhibit C.FRPO.18.

ENBRIDGE GAS DISTRIBUTION INC. AND UNION GAS LIMITED

Answer to Interrogatory from
Building Owners and Managers Association ("BOMA")

Rate Setting Issues List – Issue No. 1

Reference: Z-factor Questions, pp 11-12

Question:
(a) Please explain more fully why an increase in interest rates of any magnitude should qualify as a Z-factor. Please discuss. Why is this not a risk that EGD should adopt as part of its ten-year claim on energy savings? Please provide any precedents in either the natural gas or electricity cases in Ontario where a change in interest rates during an IRM term have been approved as a Z-factor.
(b) With respect to the request that government policy changes, such as climate policy, be considered for Z-factor treatment, given that the government's climate change policy is now well known, please explain why potential evolution of that policy should not be considered a risk of doing business and not eligible for Z-factor treatment.
(c) Given that EGD's Z-factor materiality criteria in EB-2012-0459 was $1.5 million, and given the fact that Amalco is at least 5/3 larger than EGD, why should the materiality threshold for Amalco not be at least $2.5 million? Please discuss fully. Please explain fully why the applicants think the materiality factor for the merged utility should be only $1 million.

Response

a-b) Please see the response to SEC Interrogatory #10 found at Exhibit C.SEC.10.

c) Please see the response to Board Staff Interrogatory #23 found at Exhibit C.STAFF.23.

ENBRIDGE GAS DISTRIBUTION INC. AND UNION GAS LIMITED

Answer to Interrogatory from
Building Owners and Managers Association ("BOMA")

Rate Setting Issues List – Issue No. 1

Reference: *Ibid, p13*

Question:
(a) In calculating the ICM materiality threshold value, please explain why it is appropriate for Union to use a value for rate base from six years ago (2013), given the very rapid growth in Union's gas utility rate base since that time.
(b) The evidence states variously that Amalco "may" or "will" apply for rate adjustments using the ICM during any deferred rebasing period. Please confirm that the correct version is that Amalco will apply for ICMs. Will ICMs be used, or could they be used, to fund the implementation costs listed in Exhibit B, Tab 1, Attachment 12 in EB-2017-0306. Please discuss fully.
(c) Please provide a rate base continuity schedule for Union from 2012 to 2018, inclusive. Please show the relationship of the 2018 rate bases for Union and EGD to the 2019 pro forma rate base shown on Attachment 11 of EB-2017-0306.
(d) Please explain why the Board should not employ the method traditionally used by the Board to calculate the cost of capital for the IRM period as at the time of this application (debt and equity) and not change it simply because Amalco wishes to increase the ICM (deferred rebasing period) from five to ten years. Why should changes to the cost of capital not be a risk of doing business given the Amalco's proposed claim to 100% of the savings over a ten year period? (BOMA assumes the 300 basis point threshold for earnings sharing in years six to ten is unlikely to come into play because of its very large size).
(e) Please confirm that if the Board were to authorize a five-year custom IR for Amalco, Amalco would not be eligible for the ACM/ICM, but would be limited to the capital expenditures forecasted over the plan period.
(f) Please provide the actual ROEs achieved by each of EGD and Union in the years 2012 through 2017, inclusive. Please indicate whether these were actuals, or were "normalized" in any way.

Response

a) Please see the response VECC Interrogatory #29 at Exhibit C.VECC.29.

b) With respect to Amalco's plans to use the ICM, please see response to Board Staff Interrogatory #5 (a) found at Exhibit C.STAFF.5. With respect to costs associated with integration, please see response to Board Staff Interrogatory #24 found at Exhibit C.STAFF.24.

c) Please see Table 1 below.

EB-2017-0306, Exhibit B, Tab 1, Attachment 11, page 3 shows Amalco's pro forma balance sheet, not rate base. The pro forma balance sheet contains certain items not included in rate base, such as unregulated assets and certain other assets and liabilities. Conversely, rate base includes certain items not included on the pro forma balance sheet, such as working capital that is calculated using the Board-approved methodology. Also, the pro forma balance sheet is at a point in time, whereas rate base is an average of monthly averages consistent with Board-approved methodology.

Table 1
2012 – 2018 Union/EGD Rate Base ($millions)

Line No.	Particulars	**2012** (1)	**2013** (2)	**2014** (3)	**2015** (4)	**2016** (5)	**2017** (6)	**2018** (7)
1	Rate Base – Union	3,749.1	3,783.9	3,976.8	4,228.4	4,758.4	5,473.6	6,152.8
2	Rate Base – EGD	4,010.6	4,293.2	4,701.3	5,079.8	5,909.0	6,465.2	6,703.2

Notes:
(1) Union's actual rate base figure from EB-2013-0109, Updated Evidence, Exhibit A, Tab 2, Appendix A, Schedule 18. EGD's actual rate base figure from EB-2013-0046, Application and Evidence, Exhibit B, Tab 2, Schedule 1.
(2) Union's actual rate base figure from EB-2014-0145, Revised Evidence, Exhibit A, Tab 2, Appendix A, Schedule 18. EGD's actual rate base figure from EB-2012-0459, Undertaking Response, Exhibit J1.2.
(3) Union's actual rate base figure from EB-2015-0010, Corrected Evidence, Exhibit A, Tab 2, Appendix A, Schedule 18. EGD's actual rate base figure from EB-2015-0122, Application and Evidence, Exhibit B, Tab 2, Schedule 1.
(4) Union's actual rate base figure from EB-2016-0118, Corrected Evidence, Exhibit A, Tab 2, Appendix A, Schedule 18. EGD's actual rate base figure from EB-2016-0142, Application and Evidence, Exhibit B, Tab 2, Schedule 1.
(5) Union's actual rate base figure from EB-2017-0091, Application and Evidence, Exhibit A, Tab 2, Appendix A, Schedule 18. EGD's actual rate base figure from EB-2017-0102, Application and Evidence, Exhibit B, Tab 2, Schedule 1.
(6) Union's 2017 actual rate base figure is expected to be included in the Application and Evidence for EB-2018-0105, but is draft at this time and may change. EGD's 2017 actual rate base figure is expected to be included in the Application and Evidence for EB-2018-0131, but is draft at this time and may change.
(7) Union's 2018 budgeted rate base. EGD's 2018 forecast rate base.

d) Please see response to Board Staff Interrogatory #14 at Exhibit C.STAFF.14.

e) The Applicants have not applied for a 5 year Custom IR mechanism and the information included in the amalgamation application cannot be interpreted as meeting Custom IR application requirements. The OEB's Handbook for Utility Rate Applications specifies that ICM or ACM mechanisms for funding capital are not available for utilities setting rates under Custom IR.

f) Please see response to LPMA Interrogatory #18 at Exhibit C.LPMA.18.

ENBRIDGE GAS DISTRIBUTION INC. AND UNION GAS LIMITED

Answer to Interrogatory from
Building Owners and Managers Association ("BOMA")

Rate Setting Issues List – Issue No. 1

Reference: Exhibit B, Tab 2 – Questions for NERA

Question:
(a) Please provide the copies of NERA's final proposal to EGD and Union, and the contract executed for the service, including the Statement of Work and all other pertinent information.

(b) Please confirm that your mandate did not include the development of a total productivity factor for the natural gas industry in Canada. Please discuss.

(c) What is the productivity growth, or decline of the Canadian, and separately, the American, gas distribution industry over the last twenty years? What is the total factor productivity growth over the last twenty years (or for as long as data is available) for the two industries.

(d) How long have the utilities regulated by the AUC been subject to incentive rate-making using a price cap or revenue cap formula? Have they been subject to PBR for a different period of time than Ontario electricity and gas utilities? Please explain fully with respect to each major Alberta gas and electric utility.

(e) Do you agree that whether the stretch factor the Ontario regulator applies derives from the relative efficiencies of the utilities at a point in time, or the level of its total productivity index per sé, the application of the stretch factor still involves the regulator making a judgement about the need for a stretch factor in the particular amount?

Response:

a) Please see the response to Board Staff Interrogatory #32, Attachments 4 to 6 found at Exhibit C.STAFF.32.

b) Confirmed.

c) Given that no data set similar to FERC Form 1 exists for gas distribution (because gas companies are not FERC regulated), and the similarity in operations of gas and electric distribution, Dr. Makholm uses electric and gas/electric combined data as reported in FERC

Form 1. Similarly, no comprehensive, objective data set exists for Canadian utilities. Given the similarities in utility operations and regulations in the two countries, Dr. Makholm uses FERC Form 1 data in his calculations. See responses to Board Staff Interrogatory #36 found at Exhibit C.STAFF.36 and Board Staff Interrogatory #38 (d) found at Exhibit C.STAFF.38.

d) The Alberta utilities have been subject to the current incentive rate-making plan initiative by the AUC since 2013, following the AUC's decision in 2012 (see Alberta Proceeding 566, Decision 2012-237, ¶4). In that respect, the period is different than that for the Ontario electric and gas utilities, as Dr. Makholm summarizes the OEB's PBR history in his testimony on pages 10-12, and 15-16.

e) Please see Dr. Makholm's Direct Testimony found in EB-2017-0307 at Exhibit B, Tab 2, Q/A19.

ENBRIDGE GAS DISTRIBUTION INC. AND UNION GAS LIMITED

Answer to Interrogatory from
Building Owners and Managers Association ("BOMA")

Rate Setting Issues List – Issue No. 2

Reference: Conformance with RFF; B-1, p37

Question:
"In preparation for their respective 2019 rate applications, both EGD and Union undertook extensive customer engagement activities in an effort to understand customer preferences".

(a) Please provide copies of any and all third party customer engagement studies, customer satisfaction studies, and any other studies to determine customer needs and preferences in the last three years by both EGD and Union.

(b) If no third party expert firm were used, please provide copies of all internal surveys, consultations, engagement documents, used by Union to determine customer needs and preferences, together with the customer responses to such efforts.

(c) Did either EGD or Union conduct any customer engagement activity specifically to determine customer needs and preferences with respect to the proposed merger, or were questions designed to elicit such needs and preferences as part of the studies, consultations, referred to in (a) or (b) above?

(d) Please confirm that any study conducted (and the results from the study) during the proposed deferred rebasing period will be included in the next annual rate increase application.

(e) Does EGD agree that the feature of the Z-factor should be those provided in EB-2012-0459, at pp18-20? If not, please explain why the proposed Z-factor should be defined differently.

Response

a) The customer engagement studies quoted in the evidence reference are provided in the response to CCC Interrogatory #18 found at Exhibit C.CCC.18. Those studies include the most recent and relevant customer communication and responses.

b) Third party expert firms were used.

c) No.

d) Customer engagement studies will be filed in any application requiring their use, such as any incremental capital mechanism rate applications.

e) The Applicants proposed Z factor threshold and criteria are found at EB-2017-0307, Exhibit B, Tab 1, pages 11 to12. Please see the response to FRPO Interrogatory #21 found at Exhibit C.FRPO.21 for additional context on the Applicants' Z factor proposal.

ENBRIDGE GAS DISTRIBUTION INC. AND UNION GAS LIMITED

Answer to Interrogatory from
Building Owners and Managers Association ("BOMA")

Rate Setting Issues List – Issue No. 3

Reference: ***Rates Harmonization***

Question:
Please confirm each of the rate zones maintain its current rate structure. When a cost allocation study is completed for the 2019 rate application, will Amalco propose common rate options, classifications, definitions, and structures for the entire Amalco service area, or will the existing Union and EGD rate options classifications, definitions, and structures remain in place?

Response

As indicated at Exhibit B, Tab 1, p. 29, Lines 11 to13, Amalco will maintain the existing rate zones (EGD, Union North and Union South) during the deferred rebasing period. Amalco is not completing a cost allocation study for 2019. Please also see the response to CCC Interrogatory #31 found at Exhibit C.CCC.31.

ENBRIDGE GAS DISTRIBUTION INC. AND UNION GAS LIMITED

Answer to Interrogatory from
Building Owners and Managers Association (“BOMA”)

Rate Setting Issues List – Issue No. 13

Reference: *Ibid, p31/Attachment 5*

Question:

(a) Please provide a copy of the Normalized Average Consumption ("NAC") study that Union agreed to file in EB-2016-0118, but which it has not yet filed. Has the study been completed? If not, can Union file the study prior to the amalgamation? Please provide a date when the study will be filed.

(b) In the event deferred rebasing were approved for either five or ten years, please explain why, given that when commitment by EGD was made, it was anticipated that rebasing would take place in 2019. Why would the study be done no later than the end of 2019?

Response

a- b) Please see the response to Board Staff Interrogatory #59 found Exhibit C.STAFF.59.

Union will continue to review NAC as a part of Amalco. Changes to NAC if appropriate will be considered as part of a future rate proceeding. No changes are proposed as part of this application.

ENBRIDGE GAS DISTRIBUTION INC. AND UNION GAS LIMITED

Answer to Interrogatory from
Building Owners and Managers Association ("BOMA")

Rate Setting Issues List – Issue No. 14

Reference: Exhibit B, Tab 1, Attachment 2

Question:

(a) Why does the scorecard not include an annual customer satisfaction survey by a respected third party advisor, as in the case with electricity distribution scorecard?

(b) Please explain why a more comprehensive scorecard should not be developed more akin to the scorecards required of electricity distributors, including a safety matrix (damages and injuries to third parties, or person or property, other measures of reliability, violation or absence of violation of government/gas industry pipeline safety regulations, and the like); and for public policy, cost per unit of emission credits/allowances over time.

Response

a) The Applicants regularly perform customer satisfaction surveys and will continue to do so as Amalco.

b) The proposed scorecard addresses customer focus, operational effectiveness, public policy responsiveness and financial performance. Safety and reliability are addressed within the operational effectiveness section.

ENBRIDGE GAS DISTRIBUTION INC. AND UNION GAS LIMITED

Answer to Interrogatory from
Building Owners and Managers Association ("BOMA")

Rate Setting Issues List – Issue No. 15

Reference: *Ibid, p27*

Question:
Please provide copies of each of the reports provided to the Board during EGD's 2014-2018 custom IR and Union's 2014-2018 price cap IRM, for each of 2014 through 2017.

Response

EGD's and Union's stakeholder presentations were provided as part of their annual non-commodity deferral and earnings sharing proceedings as shown in the table below. Due to the timing of the Board's decision on EGD's Custom IR application (July 17, 2014), EGD was not able to hold a session in 2014.

	Year	Case Number	Filed	Evidence Reference
EGD	2015	EB-2015-0122	May 20, 2015	Exhibit D1, Tab 3, Schedule 1
EGD	2016	EB-2016-0142	April 20, 2016	Exhibit D1, Tab 3, Schedule 1
Union	2014	EB-2014-0145	May 2, 2014	Exhibit A, Tab 4, Appendix B
Union	2015	EB-2015-0010	April 15, 2015	Exhibit A, Tab 6
Union	2016	EB-2016-0118	April 19, 2016	Exhibit A, Tab 5

ENBRIDGE GAS DISTRIBUTION INC. AND UNION GAS LIMITED

Answer to Interrogatory from
Building Owners and Managers Association ("BOMA")

Rate Setting Issues List – Issue No. 16

Reference: *Ibid, p27*

Question:
Please explain why the proposed biennial stakeholder meeting should not be provided every year, rather than every other year, given the complexity of the proposed changes, the large amounts of money involved, and the importance of protecting customers through the ICM term, whichever ICM approach is used, but especially in the event the proposed ten-year rebasing period is approved.

Response

Please see the response to OAPPA Interrogatory #8 found at Exhibit C.OAPPA.8.