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Ontario

BY E-MAIL

March 9, 2018

Kirsten Walli
Board Secretary
Ontario Energy Board
2300 Yonge Street, 27th Floor
Toronto, ON M4P 1E4

Dear Ms. Walli:

Re: Enbridge Gas Distribution Inc. and Union Gas Limited
MAADs Application
OEB File Number: EB-2017-0306 / EB-2017-0307

In accordance with OEB's Decision and Procedural Order No. 3, please find attached OEB staff interrogatories in the above proceeding. The attached document has been forwarded to the applicant and to all other registered parties to this proceeding.

Following the structure of the Issues List included in Decision and Procedural Order No. 3, OEB staff interrogatories are presented in two sections. The first section includes MAADs related interrogatories. The second section includes rate-setting mechanism related interrogatories. Within each section, numbering of the interrogatories is in the format Issue#-Staff-IR#.

Yours truly,

Original Signed By

Khalil Viraney
Project Advisor

Encl.

Ontario

OEB Staff Interrogatories

Enbridge Gas Distribution Inc. and Union Gas Limited

MAADs and Rate-Setting Mechanism Application

EB-2017-0306 / EB-2017-0307

March 9, 2018

INTERROGATORIES ON AMALGAMATION APPLICATION – EB-2017-0306

2-Staff-1

Ref: Exhibit B, Tab 1, pp. 20 & 26, Tables 3 & 4

Preamble:

Table 3 in the evidence provides a comparison between annual revenue requirement for Enbridge Gas and Union Gas were they to continue to operate as stand-alone utilities as compared to the estimated revenue requirement as an amalgamated entity operating under a price cap mechanism over the deferred rebasing period. The cumulative benefit to customers over the deferred rebasing period is $410 million.

Questions:

a) Are the revenue requirements of Amalco that are provided in Table 3 net of potential O&M savings provided in Table 4? If yes, does it take into account the minimum or maximum potential savings?
b) Table 3 provides the estimated annual increase in the revenue requirement of the amalgamated utility from 2019 to 2028. The revenue requirement shows an increase for each of the years. Are the savings in any of the deferred years equal to or greater than the annual increase to the revenue requirement?

2-Staff-2

Ref: Exhibit B, Tab 1, pp. 25-37

Preamble:

The applicants in their evidence have identified specific cost efficiency opportunities. These opportunities exist in the areas of customer care, distribution work management, utility shares services, storage and transmission, management functions and other functions. The applicants note that significant software system costs and implementation will take place over the deferred rebasing period from 2019 to 2028 to support the integration. Large scale system implementations will be planned to allow for staff to be resourced to these projects and to support change management and the adoption of the new systems and processes by employees and vendors.

Questions:

a) In the opinion of the applicants, what is the expected timeline to achieve full integration of systems and functions for the amalgamated utility?

b) What functions will not be fully integrated within the first five years? Please provide further information for those functions that will not be integrated within five years.
c) Will any of the measures for system integration and realization of efficiencies require additional staffing, apart from external consultants, during the proposed deferred rebasing period? If yes, please provide details.

2-Staff-3

Ref: Exhibit B, Tab 1, p. 26, Table 4

Preamble:

The applicants suggest that the benefits of amalgamation arise from greater operating efficiencies, an opportunity to allow for greater strategic focus, and a greater capability to face the challenges and opportunities of market developments in the Ontario energy sector. Notwithstanding that detailed implementation plans have yet to be developed, the applicants have summarized the estimated capital investments needed to achieve these synergies as well as the associated OM&A savings in Table 4 (reproduced below).

High Level Minimum and Maximum Cost and Savings Estimate ($ Millions)

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

Questions:

a) For each line item in Table 4, please provide additional commentary on how each investment is expected to translate into the expected savings, and how the minimum and maximums were estimated.
b) Please explain what assumptions have been made by the applicants with respect to the expected investments and savings.
c) Please identify any factors or risks that may affect the achievement of the expected savings.

4-Staff-1

Ref: Exhibit B, Tab 1, p. 5

Preamble:

The evidence notes that in accordance with the Consolidation Handbook, the applicants are seeking an Earnings Sharing Mechanism (ESM) consistent with the MAADs policy framework, specifically an ESM for years six through ten of the deferred rebasing period. At the same time, in order to ensure a successful amalgamation, the applicants have chosen to defer rebasing for 10 years. The applicants have also filed a separate rate setting mechanism application (EB-2017-0307) which proposes an annual index mechanism along with certain non-routine adjustments.

Questions:

If the OEB were to approve a shorter deferred rebasing period of five years for example and an ESM that begins in year one, do the applicants intend to:

a) Proceed with the amalgamation
b) Propose a Price Cap IR methodology to set rates from 2019 to 2024.

4-Staff-2

Ref: Exhibit B, Tab 1, p. 24

Preamble:

It is stated that the applicants have assumed that over the deferred rebasing period, Amalco will be subject to a price cap mechanism that will allow for the pass-through of discrete capital projects using the Incremental Capital Module (ICM).

Questions:

a) Please discuss the applicants' view as to whether the proposed ICM is consistent with OEB policy as documented in the Consolidation Handbook and the *Report of the Board: New Policy Options for the Funding of Capital Investments*.
b) Please provide a list of known or potential capital projects for which the applicants intend to seek ICM treatment.

4-Staff-3

Ref: Exhibit B, Tab 1, pp. 34-35

Preamble:

The evidence noted the integration opportunities in the storage and transmission operating business function and consolidation of the Gas Control and Gas Supply functions. The applicants have identified some opportunities for the integration of functions related to gas supply settlement processes. The primary cost savings are expected to come from harmonizing the SCADA systems, process change to optimize maintenance costs and alignment of contracts. The savings are estimated to be an average of $3 million per year over the 10 years, or approximately 10% of the annual $30 million in cost.

Questions:

a) Please explain what the savings of $3 million per year relate to with respect to storage and transmission and other gas supply functions.
b) The savings are estimated to be $3 million over 10 years. Does the 10-year period refer to the deferred rebasing period? If yes, are the savings going to be realized from year 1 (2019)?
c) Please provide more information on the integration of storage functions including any additional costs, timeline and potential savings.
d) What will be the total storage requirements of Amalco in-franchise customers?

4-Staff-4

Ref: Exhibit B, Tab 1, p. 42

Preamble:

An Earnings Sharing Mechanism (ESM) does not form part of the applicants' proposal in the Rate Framework application (EB-2017-0307). In its merger application (EB-2017-0306), the applicants state the following:

> Consistent with the OEB's requirements for consolidating entities requesting a deferred rebasing period of greater than five years to present an ESM, Amalco will have an ESM beginning in year six (2024). If, in any calendar year from 2024 to 2028, the actual utility return on equity (ROE) is greater than 300 basis points above the allowed ROE as set out under the OEB's policy, the excess earnings above 300 basis points will be shared 50/50 between the ratepayers and the shareholders.

Questions:

a) Please provide the design for each of Union Gas' and Enbridge Gas' ESM that were approved for the 2014-2018 period.
b) Please provide the actual earnings sharing calculations and actual ROE for each year 2014-2017 for both Union Gas and Enbridge Gas.
c) Please explain why the applicants have proposed an ESM that is significantly more beneficial to the applicants' shareholders than either of Union Gas' or Enbridge Gas' most recent ESM designs.

d) Please provide rationale supporting the applicants' proposal that the ESM should begin in year 6 of the deferred rebasing period. Please explain why the applicants do not believe that the ESM should begin in the first year of the deferred rebasing period.

5-Staff-1

Ref: Standard Leave to Construct Conditions of Approval

Preamble:

As a condition of approval for leave to construct (LTC) projects, applicants are required to submit to the OEB post-construction reports. Typically, these reports are due within three months of the project's in-service date. The Application is silent on whether currently outstanding LTC post-construction reports will be filed within three months of the projects' in-service date or at some other time (e.g., coinciding with the end of the 10 year deferred rebasing period).

Questions:

a) Do the Applicants agree that currently outstanding LTC post-construction reports should be filed with the OEB within three months of the projects' in-service date? If not, please explain.
b) Please confirm that the applicants will comply with all applicable reporting obligations that have been imposed by an order of the OEB.

6-Staff-1

Ref: Exhibit B, Tab 1, p. 14

Preamble:

The evidence notes that additional equity required to balance the capital structure for Union Gas in 2018 will be provided through Enbridge Gas' shareholder, Enbridge Energy Distribution Inc., and is not expected to result in a material change to the preliminary evaluation based on estimated enterprise value.

Questions:

a) Why does Union Gas require additional equity in 2018 and what is the current capital structure of Union Gas?
b) What is the total additional equity that will be required for Union Gas?
c) What is the expected change of the equity injection to the preliminary evaluation?

6-Staff-2

Ref: Exhibit B, Tab 1, pp. 40-41

Preamble:

The applicants note that Enbridge Gas relies on long-term contracts with Union Gas for transportation and storage services to meet the gas supply requirements of customers in Enbridge Gas' franchise areas. Transportation services are provided at regulated rates and storage services are provided at market rates. The cost consequences of these contracts are passed through to customers in rates.

Despite the fact that the contracts will cease to have effect upon amalgamation, the applicants have stated that they will treat current contractual arrangements as continuing services for the existing term of the pre-amalgamation contracts. After this time, Amalco will evaluate options.

Questions:

a) Please advise whether there are any legal or practical reasons why the pre-amalgamation transportation and storage contracts cannot cease at the time of amalgamation (as opposed to waiting until contract expiry).
b) Please provide rationale supporting the notional treatment by Amalco of Enbridge Gas' legacy in-franchise customers as ex-franchise from a transportation and storage services perspective (at least with respect to the access of Union Gas' assets) after amalgamation.
c) Please provide an estimate (avoiding confidential filing if possible) of the current unit rate differential between pricing the Enbridge Gas storage contracts at market rates and regulated cost of service based rates.
d) Please provide the quantity of Union Gas' storage capacity that would be converted from non-rate regulated to rate regulated to meet the requirements of Enbridge Gas' existing storage contracts with Union Gas (assuming the pre-amalgamation contracts cease to exist and Enbridge Gas' legacy in-franchise customers are treated as in-franchise by Amalco). Please discuss the applicants' position on this type of conversion and advise whether the applicants believes this would be allowable in the context of the Natural Gas Electricity Interface Review (NGEIR) decision.
e) Please confirm that the amounts paid by Enbridge Gas' legacy in-franchise customers to Amalco after amalgamation for unregulated storage services will entirely be to the benefit of Amalco's shareholder (and will not form part of the revenues earned by the regulated company).
f) Please discuss whether the regulated transportation service costs paid by Enbridge Gas' customers to Union Gas under its pre-amalgamation contracts are higher or lower than they otherwise would be if Enbridge Gas' legacy customers are treated as in-franchise customers by Amalco. Please explain how the revenues received by Union

related to the provision of ex-franchise transportation services are treated. Do these revenues operate to offset the costs paid by Union Gas' in-franchise customers? Would an increase to the amount paid by Enbridge Gas' legacy customers for transportation services to Union Gas decrease the rates paid by Union Gas' in-franchise customers?

g) Please advise whether total ratepayer savings (across all of Amalco's in-franchise customers) would be generated if Enbridge Gas' legacy in-franchise customers are treated as in-franchise customers of Amalco with respect to the provision of transportation and storage services. Please provide a high-level estimate of those savings for each year of the proposed deferred rebasing period (broken down as between transportation and storage related savings). Please also show the savings separated as between Union Gas' and Enbridge Gas' legacy in-franchise customers.

h) Please discuss whether, as an adjustment to regulated rate base, revenue requirement, cost allocation and rate design for 2019, Amalco could recalculate its transportation and storage rates for both Union Gas' and Enbridge Gas' legacy customers as necessary to reflect the treatment of all customers as in-franchise (with the conversion of any market-based services currently provided to Enbridge Gas' legacy customers to regulated services).

i) The applicants note that after the pre-amalgamation contracts expire, it will consider its options to replace Enbridge Gas' pre-amalgamation contracts.

    i. Please provide the timing of the expiry for each of Enbridge Gas' existing transportation and storage contracts. Please provide the date on which the final pre-amalgamation contract expires.
    ii. Please advise whether Amalco will consider, after contract expiry, the conversion of a portion of Union Gas' unregulated storage capacity to regulated storage capacity set aside to serve the needs of Enbridge Gas' legacy customers.

9-Staff-1

Ref: Exhibit B, Tab 1, p. 15

Preamble:

Enbridge Gas and Union Gas and their then parent affiliate companies provided undertakings (Undertakings) to the Lieutenant Governor in Council for Ontario, approved by Order in Council 2865/98 on December 9, 1998 and made effective March 31, 1999.

Question:

What is the Applicants' position on the idea of the OEB replacing the Undertakings with one or more conditions of approval of the proposed merger? If the applicants support this idea, what conditions would they suggest?

9-Staff-2

Ref: Exhibit B, Tab 1, pp. 16-17

Preamble:

The application states that with the creation of Amalco, the Union Gas Undertakings to the Lieutenant Governor in Council for Ontario will cease to have effect. Accordingly, Amalco will not be required to have a head office in the Municipality of Chatham-Kent as compared to Union Gas that was required to maintain a head office in Chatham-Kent. However, Union Gas has indicated that Amalco will continue to maintain a significant presence in Chatham-Kent.

Questions:

a) What kind of presence will Amalco maintain in Chatham-Kent and what functions of Amalco will remain in Chatham-Kent post amalgamation?
b) Would the applicants agree to an OEB imposed condition that would require it to maintain a significant presence in Chatham-Kent? If so, do the applicants have any proposed wording for such a condition?

9-Staff-3

Ref: Exhibit B, Tab 1, Attachment 6, p. 2

Preamble:

Section 7 of the Amalgamation Agreement states that there shall be no restriction on the business which the amalgamated corporation is authorized to carry on.

Question:

Please discuss how this provision is consistent with the restrictions on business activities contained in the applicants' Undertakings to the Lieutenant Governor in Council for Ontario.

INTERROGATORIES ON RATE-SETTING MECHANISM APPLICATION – EB-2017-0307

1-Staff-1

Ref: Exhibit A, Tab 2, pp. 2-3
Exhibit B, Tab 2, p. 5

Preamble:

The proposed IRM for Amalco features an Incremental Capital Module with the following provisions:

> 7. The Applicants further apply to the OEB for approval of the following parameters in calculating treatment of qualifying capital investments through the OEB's Incremental Capital Module:
>   a) Based on separate materiality threshold calculations using rate base and depreciation expense approved in 2013 rates for Union Gas and 2018 rate for Enbridge Gas.
>   b) Using incremental cost of capital to calculate the revenue requirement to fund incremental capital investment,
>   i. 64/36 debt to equity ratio
>   ii. incremental cost of long-term debt issued
>   iii. allowed return on equity ("ROE") based on the OEB's cost of capital formula for the year the investment is placed in service

Further information on the ICM proposal is also provided in Exhibit B, Tab 1, pp. 5, 2-16.

Questions:

a) Do the applicants' propose to apply the incremental cost of capital only to the underfunded portion of incremental capital investment, to all incremental investments, or something else?
b) Please comment on the degree to which the GDP-IPI (FDD) reflects changes in the cost of capital.

1-Staff-2

Ref: Exhibit B, Tab 1, p. 5
EB-2017-0086 – Exhibit E1, Tab 1, Schedule 1, p. 1, Tables 2 & 3

Preamble:

The applicants proposes a variance from the OEB's policy for the capital funding through the

ICM as it proposes to use the following variations:

Recovery through rates for qualifying incremental capital investments through the OEB approved ICM:

a. Based on separate materiality threshold calculations using rate base and depreciation expense last approved by the OEB (2013 rates for Union Gas and 2018 rates for Enbridge Gas);
b. Using incremental cost of capital to calculate the revenue requirement to fund incremental capital investment:
    i. 64/36 debt to equity ratio;
    ii. incremental cost of long-term debt issued;
    iii. allowed return on equity ("ROE") based on the OEB's cost of capital formula for the year the investment is placed in service;

A review of Enbridge Gas' 2018 rate application (EB-2017-0086, Exhibit E1, Tab 1, Schedule 1, page 1, Tables 2 and 3) shows that Enbridge Gas has both short-term debt and preferred shares in its deemed capital structure on which the approved 2018 distribution rates are based.

Similarly, in the October 17, 2012 Decision and Order EB-2011-0210, at page 50, and the Settlement Agreement at Exhibit B, Schedule 3 and Exhibit J5.4, page 2/ll. 7-12, Union Gas also has short-term debt and preferred shares.

Under the OEB's ICM/ACM policy developed for electricity distributors, the approved cost of capital, including short-term and preferred shares, are reflected in the determination of the incremental revenue requirement for qualifying ICM or ACM projects.

Questions:

a) Why are the applicants excluding consideration of short-term debt or preferred shares, and applicable rates, in the calculation of the incremental revenue requirement for qualifying ICM capital projects?
b) Under an assumption that the current cost (i.e., interest rate(s)) of incremental long-term debt to fund the incremental capital project is approved as proposed, what information will Amalco file and how is it proposing that that information be reviewed and tested in the Price Cap IR application for which ICM funding and rate riders are proposed?

1-Staff-3

Ref: Exhibit B, Tab 1, p. 8

Preamble:

The applicants have proposed that inflation be represented by the annual percentage change in the (National) Gross Domestic Product – Implicit Price Index (Final Domestic Demand) (GDP-IPI (FDD)).

This measure has been used as the inflation index in PBR/IRM plans for natural gas distributors for over 10 years. The GDP-IPI (FDD) was also used as the inflation measure for electricity distributors for 2nd and 3rd Generation IRM plans. Since 2013, a two-input Input Price Index (IPI) has been used to get a measure of inflation somewhat more specific to the sector. For current electricity distribution IRM rate adjustment mechanisms, the IPI is a weighted average of labour and non-labour (i.e., capital and materials) components, with the weights based on the sector-specific cost proportions of the revenue requirement. The GDP-IPI (FDD) is used as the non-labour inflation index, while the labour inflation index (for electricity) is the annual percentage change in Average Weekly Earnings – Ontario – All Businesses excluding Unclassified, including Overtime (AWE). For electricity distributors, the weights are 30% labour and 70% non-labour.

For OPG's price cap plan for Prescribed Hydroelectric Generating Plan Payment Amounts approved in EB-2016-0152, the same IPI methodology was approved but with weights more representative of OPG's labour and non-labour components for hydroelectric generation. The weights for the OPG plan IPI are 88% non-labour and 12% labour.

Questions:

a) Please provide the applicants' views on the advantages and disadvantages of using GDP-IPI (FDD) versus a two-factor IPI with labor and non-labour weights representative of the natural gas distribution sector.
b) If a measure such as a natural gas IPI were considered, please provide the applicants' proposals for weights. Please provide support for these estimates.
c) What, if any, alternative inflation measures did the applicants consider, and why were such measures not preferred?
d) Are there any other measures of inflation that the applicants think should be considered? Please provide details and support for any such potential inflation measures.

1-Staff-4

Ref: Exhibit B, Tab 1, p. 9

Preamble:

As part of its argument for the proposed base X-factor and stretch factor of 0, the applicants point to forecasts for increasing interest rates:

> In addition, economists currently believe the Canadian economy will be exposed to increasing interest rates over the next decade. Both EGD and Union Gas have refinanced virtually all of their existing long-term debt based on historically low interest rates that have existed over the past 10 years. Amalco will be required to refinance approximately 50% of its existing long-term debt during the deferred rebasing period. Higher interest rates combined with refinancing a significant portion of existing long-term debt could put significant pressure on Amalco's earnings.

Questions:

a) Do the applicants believe that changes in interest rates do not affect other businesses and end consumers, and thus would not be reflected in measures of inflation such as the GDP-IPI?
b) Please provide the weighted average cost of long-term debt for Union Gas:
    i. as reflected in its last rebasing application for 2013 distribution rates;
    ii. as of December 31, 2107.
c) Please provide Enbridge Gas' weighted average cost of long-term debt:
    I. as of December 31, 2017;
    II. as approved in Enbridge Gas' most recent natural gas distribution rate application for 2018 rates.
d) Please provide data on the amount of long-term debt with the following maturities, for each of Enbridge Gas and Union Gas.

Maturity of Debt Instrument (when executed)	Number of Current Debt Instruments	Aggregate Principal ($M)	Percentage of total debt principal
1 to less than 5 years			
5 to less than 10 years			
10 years to less than 20 years			
20 years to less than 30 years			
30 years or more			
Total			**100%**

e) What is the i) average and ii) median maturity length of long-term (greater than 1 year) for each of Enbridge Gas and Union Gas?
f) Given a proposed “stay-out” period of 10 years, and the average or median term and the vintages of existing debt, does Amalco consider that having to re-finance “approximately 50% of its existing long-term debt” as being abnormal compared to its historical ability to plan for and manage?
g) Please identify and support any historical periods where there were similar circumstances of changing interest rates, and identify what, if any pressures, were experienced with respect to either Enbridge Gas’ or Union Gas’ earnings during these periods.

1-Staff-5

Reference: Exhibit B, Tab 1, p. 10

Preamble:

In the Y factor section of the proposed plan, the applicants state that:

> The LRAM will continue to exist for the contract rate classes.
>
> Normalized Average Consumption/Average Use Adjustment
>
> The Applicants are proposing to continue to adjust rates annually to reflect the declining trend in use.

Question:

Please provide a detailed discussion of how the normalized average consumption/average use adjustment(s) would work under the proposed plan.

1-Staff-6

Ref: Exhibit B, Tab 1, p. 14

Preamble:

In Table 1, the applicants provide an “Illustrative ICM Threshold Calculation for 2019 for EGD and Union”.

Questions:

a) Please provide the calculations in Microsoft Excel format, if available
b) Please provide the source data, in spreadsheet format if available, and references for the data sources.

1-Staff-7

Preamble:

The applicants’ proposed IRM plan for the deferred rebasing period does not include any off-ramps.

Question:

Please explain why the applicants have not proposed any off-ramps to the IRM plan.

1-Staff-8

Ref: Exhibit B, Tab 1, p. 10

Preamble:

The applicants have proposed that, in accordance with the current treatment, any changes to DSM program costs will be updated in rates and implemented as part of the DSM program review process.

Questions:

a) Please advise for which years of the deferred rebasing period Union Gas and Enbridge Gas currently have approved DSM budgets.
b) Please advise whether there are any current regulatory proceedings ongoing (or expected to occur in the near future) with respect to Union Gas’ and Enbridge Gas’ DSM plans. Please provide the status of those regulatory proceedings.

1-Staff-9

Ref: Exhibit B, Tab 1, p. 10

Preamble:

The applicants proposed to continue to adjust rates annually to reflect the declining trend in NAC / AU.

Questions:

a) Please confirm that the applicants propose to continue to use the existing approved methodologies for calculating annual changes in NAC / AU. Please confirm that the changes will be applied individually to each of the existing service areas (EGD, Union North, and Union South).
b) Please confirm that the applicants propose to continue the current process of truing-up the forecast to actual NAC / AU as part of the deferral account disposition process.

1-Staff-10

Ref: Exhibit B, Tab 1, p. 11

Preamble:

The applicants propose to use a materiality threshold of $1.0 million for Z-factors during the deferred rebasing period.

Questions:

a) Please provide Union Gas and Enbridge Gas' existing materiality thresholds for Z-factor claims.
b) Please provide rationale supporting the change to the Z-factor materiality threshold.
c) Please confirm that the proposed Z-factor materiality threshold is on a revenue requirement basis.

1-Staff-11

Ref: Exhibit B, Tab 1, p. 12

Preamble:

The applicants state that capital projects related to the amalgamation will be funded and managed by Amalco as an integral part of supporting achievement of synergies through the deferred rebasing period.

Question:

Please confirm that Amalco will not seek ICM treatment of capital projects that are directly related to the amalgamation.

1-Staff-12

Ref: Exhibit B, Tab 1, pp. 14-15

Preamble:

The applicants state:

> Management anticipates a need for incremental capital investment to reinforce existing pipeline systems where capacity is not available to support future growth and to replace pipeline systems (or portions of systems) where programs to extend the life of the asset are no longer the most cost-effective option. These types of capital investment are beyond what is funded through approved rates without adjustments. Rate adjustments to fund incremental capital investment in the 2014 to 2018 incentive mechanisms are addressed by Enbridge's Custom IR and Union Gas' capital pass-through mechanism. Union Gas' existing capital pass-through mechanism is consistent with the Board's ICM.

Questions:

a) Over the life of existing assets, the firms earned a cost of capital to cover debt interest and to compensate investors for the time value of their investment and commensurate with the risk and market conditions. Depreciation expense is the return of the original invested capital and debt principal, by which the firm could reinvest, or repay debt principal and free up space for obtaining new debt for new capital projects, including replacement of existing assets that fail or reach end-of life (EOL). With respect to existing assets that have reached EOL and require replacement, why do the applicants consider that replacement costs are <u>not</u> adequately funded through approved rates?

b) The statement about reinforcement to add capacity for expected added demand in the future presumes that the expected future demand will come about, and within the reasonable future. Per the OEB's policies as documented in current OEB Reports,[1] the

[1] *Report of the Board on New Policy Options for the Funding of Capital Investments: The Advanced Capital Module (EB-2014-0219)*, September 18, 2014, p. 17: "Funding shall not commence for any projects that are not forecasted to be in service during the subject IR year." and. p. 25:

In the Price Cap IR application for the year in which the capital project(s) will go into service and the applicant is seeking to commence recovery through rate riders, the distributor should provide updated, current information with respect to the above for any approved ACMs for any material changes from what was reflected in the DSP. In the case of an ICM proposal for recovery of an unanticipated capital project, or for a project for which a distributor did not have sufficient information to address need and prudence at the time of the cost of service

ICM is applied for in the year that a capital project enters service. This would imply that the forecasted demand is being realized. Additional demand, in terms of added customers or added gas consumption, will also provide additional distribution revenues. Please explain why the applicants anticipate that such reinforcement projects would result in material capital expenditures, and require ICM cost recovery treatment, beyond what is available through rates and existing rate-setting approaches, such as requiring capital contributions from the new customers based on "cost causality" and PI index analysis.

c) Please elaborate further on why and how "Union's existing capital pass-through mechanism is consistent with the Board's ICM." What are the similarities and differences, in the applicants' view?

1-Staff-13

Ref: Exhibit B, Tab 1, p. 15

Preamble:

On page 15, the applicants state:

> Amalco proposes to bring forward the Asset Management Plan(s) to provide information to the Board, as required, in the annual rate applications in support of ICM proposals. In the case of a qualifying project that requires a Leave to Construct ("LTC") application the request for approval of the proposed adjustment to rates will be filed with the LTC. Proposals to adjust rates for investments not subject to LTC will be addressed in the annual rate setting process.

In the annual rate application, the Applicants will be requesting approval of a rate adjustment to fund forecast incremental capital projects that qualify for ICM.
OEB staff acknowledges the discussions in the Rate Handbook, extending the ICM to OPG, electricity transmitters and natural gas distributors. Similarly, subject to OEB approval of extending the policies in the MAADs Handbook to natural gas distributors, OEB staff acknowledges the availability of the ICM or an analogous measure to dealing with qualifying capital investments during the "stay-out" period following an approved MAADs transaction and during which the applicant utility has rates adjusted through a Price Cap IR formula.
However, OEB staff notes the following from the *Report of the Board on the Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach*, October 18, 2012 (the RRFE Report):

application, this will be the first time that the distributor is providing such evidence. Therefore full and complete details of the project(s) must be filed, as is the current ICM policy and practice.

> <u>Incremental Capital Module (ICM)</u>
> The ICM is intended to address incremental capital investment needs that may arise during the IR term. Under 4th Generation IR, the Board's policies in respect of ICM in effect under 3rd Generation IR will continue to apply.
>
> In 2011, the Board revised its Filing Requirements for Electricity Transmission and Distribution Applications to clarify the ICM specifications on how to calculate the incremental capital amount that may be recoverable when a distributor applies for an ICM. In the Filing Requirements issued in June 2012, the ICM was further revised to remove words such as "unusual" and "unanticipated" as prerequisites to an application for incremental capital, although the requirement that the proposed expenditures be non-discretionary remains.[2]

Further in the RRFE Report:

> The Custom IR method will be most appropriate for distributors with significantly large multi-year or highly variable investment commitments that exceed historical levels. The Board expects that a distributor that applies under this method will file robust evidence of its cost and revenue forecasts over a five year horizon, as well as detailed infrastructure investment plans over that same time frame. In addition, the Board expects a distributor's application under Custom IR to demonstrate its ability to manage within the rates set, given that actual costs and revenues will vary from forecast.
>
> …
>
> There will not be an ICM in the Custom IR method.[3]

As written, OEB staff interprets the applicants' evidence as suggesting that the applicants contemplate that ICMs will be routine, rather than the exception.

While the OEB has explicitly removed the terms "unusual" and "unanticipated" from the ACM and ICM, the OEB's expectation is that ACMs or ICMs would not be the norm during a Price Cap IR term. A firm under a Price Cap IR plan would manage its capital and operating programs and costs under the rate adjustment mechanism. ICMs would only be necessary for recovery of capital-related costs for investments of material "lumpy" capital expenditures where the need for and pacing of the project is justified, and where existing rates, as adjusted through the Price Cap IR adjustment formula, are insufficient to recover the incremental annual

[2] RRFE Report, page 18
[3] *Ibid*., pp. 19-20

revenue requirement for the project.

Questions:

a) As documented in the Rate Handbook[4] and in the Board reports on New Policy Options for Capital Funding,[5] applications for incremental ICM-qualifying capital funding and the rate riders to recover the incremental revenue requirement are applied for and approved as part of a rate application for a Price Cap IR rate adjustment. Why are the applicants proposing that such requests be applied for in a LTC application?
b) Please confirm that the Asset Management Plans that Amalco is proposing to file in support of an ICM proposal will be comprehensive plans covering all of Amalco's assets, and not just covering the proposed ICM-qualifying projects. Please confirm that these will not be Utility System Plans. In the alternative to either confirmation, please explain.

1-Staff-14

Ref: Exhibit B, Tab 1
***Report of the Board: New Policy Options for the Funding of Capital Investments: The Advanced Capital Module (EB-2014-0219)*, September 18, 2014**

Preamble:

Determining the capital expenditures that would qualify for ICM treatment for a proposed capital project in a Price Cap IR rate year requires several steps to calculate:

1) The capital expenditures forecasted for the year are compared against the materiality threshold amount, which represents that level of capital expenditures funded through existing rates as adjusted for the price cap formula and for growth in customers and demand and a 10% deadband. It is only any overage of total forecasted capital expenditures in the year relative to the materiality threshold for that year for which capital funding is available.
2) Second, for the proposed and discrete capital project, the qualifying capital expenditure is the minimum of the total forecasted capital expenditure for that project and the overage calculated in (1).

[4] *Handbook of Utility Rate Applications*, October 13, 2016, page iv of Appendix B: Glossary of Terms: "An ICM request is requested and approved as part of a Price Cap IR application."
[5] *Report of the Board on New Policy Options for the Funding of Capital Investments: The Advanced Capital Module (EB-2014-0219)*, September 18, 2014, p. 23, section 7.1 and Appendix A. These policies remain unchanged in the *Report of the OEB on New Policy Options for the Funding of Capital Investments: Supplemental Report (EB-2014-0219)*, January 22, 2016.

The incremental ICM-qualifying annual revenue requirement and the ICM rate riders to recover it are derived from the result of (2) above.

Consideration of an ICM deals not only with the capital expenditures of a proposed ICM-qualifying project, but with the forecasted total capital expenditures in the year. For electricity distributors under Price Cap IR, the Distribution System Plan generally filed with and reviewed in the cost of service application to rebase rates provides a 5 year projected capital budget. The types of forecasted projects, their nature, need for, and pacing and prioritization, and the level and trending of capital expenditures is documented and tested.

For a proposed ICM project, or an ACM project reviewed in the earlier rebasing application, during the Price Cap IR application during which the ICM/ACM project will come into service, the applicant provides updated information, including updated capital expenditures. Ideally, the updates are minimal, but a material change in the forecasted capital for the project (± 30% variance for an earlier ACM project) or for total capital expenditures invites further exploration.

The applicants are not proposing rebasing in the proposed rate plan, and have not provided information on forecasted capital programs and budgets for any part of this period.

Question:

What information do the applicant's propose Amalco to file in support of its annual capital budget, and how do the applicant's propose that Amalco's forecasted annual capital budget would be reviewed and tested, along with proposed ICM-qualifying project details and dollars, as part of any ICM proposal in an annual Price Cap IR application?

1-Staff-15

Ref: Exhibit B, Tab 1, p. 15
***Report of the Board: New Policy Options for the Funding of Capital Investments: The Advanced Capital Module (EB-2014-0219)*, September 18, 2014, p. 15**
***Handbook for Utility Rate Applications*, October 13, 2016, p. 25**

Preamble:

On page 15 of Exhibit B, Tab 1, the application states:

> In the annual rate application, the applicants will be requesting approval of a rate adjustment to fund forecast incremental capital projects that qualify for ICM. In

> calculating the revenue requirement for the proposed ICM, the methodology applied will be consistent with the Board requirements with one exception [pertaining to the cost of capital parameters].

Page 25 of the Rate Handbook provides for the availability of the ICM for natural gas distributors under a Price Cap IR plan of at least 5 years:

> Natural gas utilities may choose either Custom IR or Price Cap IR. Under either approach, the term must be a minimum of 5 years. For Price Cap IR it would include a cost of service year and at least four years using an incentive adjustment mechanism.

In the, September 18, 2014, on page 15, the OEB identifies a “means test” as a requirement for ICM eligibility in any year:

> **4.1.4 The Adoption of a Means Test**
> The Board is of the view that establishing a means test would be prudent in qualifying distributors for incremental capital funding. Any distributor approved for an ACM in its most recent cost of service application must file its most recent calculation of its regulated return (RRR 2.1.5.6) at the time of the applicable Price Cap IR application in which funding for the project, and recovery through rate riders, would commence. **If the regulated return exceeds 300 basis points above the deemed return on equity embedded in the distributor’s rates, the funding for any incremental capital project will not be allowed.** Therefore, any approvals provided for an ACM in a cost of service application will be subject to the distributor passing the means test in order to receive its funding during the IR term. The same means test shall also apply going forward for new projects proposed as ICMs during the Price Cap IR term.
>
> While a means test that doesn’t allow incremental funding if a distributor is earning more than its Board-approved ROE may be a barrier to a distributor seeking efficiency improvements during the IR term, a threshold of 300 basis points retains some flexibility for distributors to maximize their earnings while also recognizing that funding in advance of the next rebasing is likely not required from a cash flow perspective. Distributors will have the option of explaining any overearnings. [Emphasis in original]

Questions:

a) Please confirm that any application for ICM-qualifying cost recovery will be subject to the means test. In the alternative, please explain the applicants' proposal.
b) Assuming the merger is approved and executed, the applicants propose to continue to operate the Enbridge Gas and Union Gas legacy service areas separately for rate-setting purposes over the plan term. Please explain how the applicants propose that the "means test" would be performed given this situation (one merged gas distribution utility but separate legacy service territories for rate regulatory purposes).

1-Staff-16

Ref: Exhibit B, Tab 1, p. 15

Preamble:

On page 15 of Exhibit B/Tab 1, the application states:

> In calculating the revenue requirement for the proposed ICM, the methodology applied will be consistent with OEB requirements with one exception [pertaining to the cost of capital parameters].

The applicants are not proposing to rebase rates, but solely to make certain adjustments to the "going-in" rates. Per the Custom IR plan that it was under for the period 2014-18, Enbridge Gas' distribution rates are, conceptually, rebased as of 2018 (reflecting certain capital and operating cost adjustments along with current cost of capital parameters). Union Gas' distribution rates were last rebased in 2013.
Under the proposed plan, Amalco would not rebase until 2029.

Questions:

If the applicants consider that the cost of capital parameters should be updated, why are the applicants not proposing that other parameters of the materiality threshold formula should also be updated? Specifically, please provide the applicants' reasons for not proposing updates to the following:

a) changes in tax rates and tax rules;
b) changes in growth (for example, calculating "g" as the geometric mean annual growth rate from 2013 to the most recent actuals).

1-Staff-17

Ref: Exhibit B, Tab 1, pp. 15-16

Preamble:

The applicants have proposed that in calculating the revenue requirement for the proposed ICM, the methodology applied will be consistent with OEB requirements with one exception. The applicants have proposed that the cost of capital will reflect the latest forecast cost of debt, incremental long-term debt requirement for the capital project and allowed ROE at the time of the application and be based on the applicants' current capital structure at 64% debt and 36% equity. This is because the OEB's ICM policy was established for five year ratemaking models and Amalco will be operating under a 10-year deferred rebasing period.

Question

Please provide the applicants' position with respect to calculating the revenue requirement for the proposed ICM if the OEB approves a 5-year deferred rebasing period for Amalco.

1-Staff-18

Ref: Exhibit B, Tab 1, pp. 30

Preamble:

In its evidence, the applicants state that Amalco will report under US GAAP financial standards. During the deferred rebasing period Amalco expects to change accounting practices and processed as part of the implementation of an integrated accounting system.

Questions:

a) Is Amalco's policy for capitalization of costs expected to materially change compared to the current practices of both Enbridge Gas and Union Gas?
b) If yes, please explain what the new cost capitalization policy will be and quantify the impact as compared to the current approved revenue requirement of both Enbridge Gas and Union Gas.
c) What is the current cost capitalization policy of Enbridge Gas and Union Gas?
d) Under the current cost capitalization policies, are costs that are capitalized material? Please quantify and provide examples as applicable.

1-Staff-19

Ref: Exhibit B, Tab 2, pp. 3-5

Preamble:

The qualifications of Dr. Makholm to testify on productivity and other incentive regulation ("IR") issues are discussed on pages 3-5 of his evidence.

Questions:

a) Please provide citations for all of Dr. Makholm's productivity studies and report the total number of productivity studies he has undertaken and the number of times he has testified on productivity issues.
b) Did Dr. Makholm's work for Ontario Hydro Services Company involve power transmission and distribution productivity studies?
c) Please provide copies of the reports Dr. Makholm prepared on productivity research for clients in Argentina, Mexico, and New Zealand (or a functioning link to their location).
d) Please provide CVs for other individuals who participated in NERA's productivity work for the applicants for this application.
e) Please provide details of Dr. Makholm's other PBR experience, including the number of projects undertaken and citations on reports and testimony (or a functioning link to their location).
f) Please provide Dr. Makholm's retainer agreement(s) with the applicants for this proceeding.

1-Staff-20

Ref: Exhibit B, Tab 2, pp. 4-5

Preamble:

Dr. Makholm states on pp. 4-5 of his evidence that:

> Most recently, I was retained as an independent expert by the Alberta Utilities Commission (the AUC) in its 2011-2012 generic "Rate Regulation Initiative"… Working independently, I directed the preparation of a TFP growth study to use for Alberta's electricity and gas distribution companies. The conclusions in that study were accepted by the AUC, in its Decision 2012-237, on all major conclusions of that PBR initiative (methods, data, transparency, output measure, time periods and possible advanced statistical methods). The AUC also adopted my "capital tracker" proposal to ensure the collection of necessary capital expenditures not covered by other elements of an incentive regulation plan. …

Question:

Is the current study filed in the applicants' rate setting application the first productivity testimony Dr. Makholm has prepared since 2012?

1-Staff-21

Ref: Exhibit B, Tab 2, p. 6
Alberta Utilities Commission Decision 2012-237

Preamble:

Dr. Makholm states on p. 6 of his evidence that:

> I recommend, on the basis of my *customary empirical analysis* in such cases, that EGD and Union should be subject to a zero *X-factor* with a zero "stretch factor". [italics added]

The Alberta Utilities Commission (AUC), in Decision 2012-237 regarding Performance-Based Regulation for Alberta utilities, makes reference the NERA's second report.

Questions:

a) Please provide working papers for Dr. Makholm's updated productivity study for the applicants.
b) Is the report filed in Exhibit JDM-2 the first or the second NERA report? If it is the first report, please file the second report.
c) What changes were made in the second report relative to the first report?
d) Does Dr. Makholm's research for the applicants, like his research for the AUC, exclude general costs and costs of customer services such as billing and collection?
e) Dr. Makholm Please prepare a run that adds back general costs and costs of customer services (other than conservation and demand management) and provide full details of the results.
f) Please discuss in detail any changes to Dr. Makholm's TFP research methodology that were made in the five years since the first generic Alberta PBR proceeding.

1-Staff-22

Ref: Exhibit B, Tab 2, pp. 15-16
Decision with Reasons EB-2012-0459 (July 17, 2014), pp. 35-37, 46-51

Preamble:

On pages 15-16 of this exhibit, Dr. Makholm states:

> I also understand that for the 2008-2012 time frame, the Board approved settlement agreements for incentive rate regulation of EGD and Union Gas, with EGD using a "revenue per customer" framework and Union Gas using a price-cap approach. The parties in the EGD settlement could not agree on an X-factor, so instead used an inflation coefficient with which to adjust rates. [footnote omitted] Similarly for the 2014-2018 period, Union Gas came to a settlement agreement with stakeholders and the parties agreed to an inflation coefficient rather than an explicit X-factor. EGD utilized the Custom IR option as described for electricity distributors above for its rate adjustment mechanism over the 2014-2019 timeframe. [footnote omitted]

In its Decision with Reasons EB-2012-0459 approving Enbridge Gas' 5-year Custom rate-setting plan, the OEB addressed the issue of productivity assumed in the forecasted capital and operating costs during the plan period.

Questions:

a) With respect to Enbridge Gas' 2008-2012 and Union Gas' 2014-2018 price cap plans, while the X-factor was not set at an explicit fixed amount, it was established formulaically in relation to the annual inflation factor. In another example, it can be argued that, methodologically, a rate freeze is a price cap of the form I – X where X = I.

   Did the applicants consider options where the X-factor is dynamically related to the I-factor? If so, what option(s) was (were) considered and why was each rejected?

b) Has Dr. Makholm considered any options where the X-factor is dynamically related to the I-factor? If so, please explain the options considered and why they were not accepted? If not, please provide Dr. Makholm's views on the reasonability of PBR plans, such as Union Gas and Enbridge Gas have previously had, where the X-factor is related to the I-factor.

c) With respect to Enbridge Gas' 2014-2018 plan, the OEB noted in its Decision with reasons that there was $162M of embedded capital budget savings over the 5-year period from 2014-2018. In addition, there were $264M of excluded capital savings, which were not certain, but dependent on certain external factors, planned studies and other future activities. The OEB noted that the sum of these represented about 9% of proposed capital expenditures over the 5-year plan period.

   With respect to productivity on OM&A expenses, the OEB addressed this on pages 46-51 of Decision with Reasons EB-2012-0459. The OEB directed that Other O&M, comprising about 55% of total O&M, be limited to an inflation adjustment of 1% per annum to incentivize execution of cost efficiencies and other operational productivity improvements; this represented a cumulative savings of $42.3M over the term of the plan.

Thus, even if there was not a defined X-factor in Enbridge Gas' most recent rate-setting plan, there were mechanisms designed into the plan, as approved by the OEB, to reflect expected productivity improvement for each of capital and operating costs. There is indication in Enbridge Gas' rates applications under the 2014-2018 plan or in this application, that Enbridge Gas has not been able to achieve expected savings, or that its financial health has been adversely impacted in a material way.

Enbridge Gas is not proposing to rebase for the proposed Price Cap IR plan.

Please explain why Dr. Makholm considers it reasonable that there should not be an X-factor (with or without a stretch-factor) for this new plan given that there was some form of non-zero productivity built into the most recent plan.

1-Staff-23

Ref: Exhibit B, Tab 2, p. 14-15

Preamble:

Under Q22 and A22, Dr. Makholm states:

> In addition to my academic work and Dissertation, I have elsewhere written at length for publication about the difficulties of trying to measure efficiency levels of regulated companies under price cap plans with the kind of data that is available.[footnote omitted] In one 2007 publication, I note the following:
>
>> Empirical data from academic TFP studies show that even the highest quality data (from the U.S. Uniform System of Accounts) produces TFP index growth rates for individual companies that are highly sensitive to vagaries and judgments on how company data is reported to government agencies. Individual data points for specific companies and years in industry-wide TFP analysis are notoriously unstable, even in the best of circumstances. [footnote omitted]
>
> None of this instability materially undercuts TFP growth studies that encompass many years of data (when the errors cancel each other out)—as in the TFP studies that I presented in Alberta and present in this proceeding.

Questions:

a) How many years of data does Dr. Makholm consider as a minimum necessary in order to be satisfied that the results of a TFP analysis are not "materially" affected by "the vagaries and judgements on how company data is reported to government agencies".
b) Does Dr. Makholm consider that the length of time for a TFP study should cover a full economic cycle (i.e. recession/down-turn and recovery)? Please explain the response.

1-Staff-24

Ref: Exhibit B, Tab 2, p. 17-18

Preamble:

In his evidence, Dr. Makholm provides a summary of the rate-setting plans that Enbridge Gas and Union Gas has been under since around 1999, with the emphasis on the multi-year plans in place for much of that period.

Question:

Both Enbridge Gas and Union Gas are completing, with 2018 rates, multi-year plans. Both utilities have had rates adjusted through multi-year plans since the early 2000s, and most multi-year plans had ESMs.

In this application, the applicants have proposed that an ESM would form part of the plan, but only for the last 5 years of the proposed plan. This proposal is based on the ESM requirement in the MAADs Handbook, designed for the electricity transmission and distribution sector, but for which the applicants are proposing extension to the natural gas distributor. Given that ESMs have been a part of most multi-year rate setting plans for Enbridge Gas and Union Gas in the past, why do the applicants presume that an ESM would not be part of any rate-setting plan for 2019 even if Enbridge Gas and Union Gas did not merge?

1-Staff-25

Ref: Exhibit B, Tab 2, p. 22
JDM-3, Tab 1

Preamble:

On this page, Dr. Makholm lists all of the companies used in the Industry Study. All of these are electric or combined gas and electric U.S. distribution utilities.

Questions:

a) Please explain why Dr. Makholm has not included any Canadian natural gas utilities in his study sample other than Union Gas and Enbridge Gas.
b) Please provide a list from the table identifying which firms in the sample are: electricity distribution; or combined natural gas and electricity.
c) Please explain why there are no U.S. natural gas distribution (only) utilities in Dr. Makholm's study.
d) Please explain why Dr. Makholm has included U.S. electric utilities in the sample, but has not included any Canadian electric utilities in his study. In particular, given his experience in various Canadian jurisdictions, it would seem that he would be familiar with and have access to data for some Canadian utilities.
e) Please explain why Dr. Makholm considers that his sample of U.S. electric and combined gas and electric utilities is appropriate for establishing an industry TFP trend on which the X-factor for Amalco, a Canadian natural gas distributor would be set.
f) Please explain how Dr. Makholm has ensured, or what analysis has been conducted by Dr. Makholm to conclude, that the efficiency and accuracy of the TFP trend is not biased by the omission of U.S. gas distributors or by the absence of any Canadian gas utilities.
g) Demand for and use of natural gas and electricity varies in different regions of North America. In Canada, and in many of the U.S. states, natural gas will be often used for space and water heating, particularly during the winter season, in addition to its use by commercial and industrial customers. Its use for agricultural purposes will also vary by region. Electricity demand and consumption will also vary by region depending on seasonal patterns commercial and industrial considerations. How has Dr. Makholm factored in exogenous environmental factors affecting each utility in the sample in his TFP analysis?

1-Staff-26

Ref: Exhibit B, Tab 2, p. 23

Preamble:

Dr. Makholm states, on page 23 of his evidence, that:

> For the distribution industry I use sales volume as the output quantity. I create an output index by combining sales volume for several different customer categories as follows: Residential, Commercial, Industrial and Public. EGD provided sales volume (10^6 m^3) data for roughly the same customer categories. However, I measure sales volume (10^6 m^3) for Union Gas using two customer categories, a General Service category and a Contract category. Union Gas' output quantity measure does not include any output

related to its ex franchise transmission business.

Question:

Please extend Dr. Makholm's mathematical analysis of the rationale for productivity research to consider the implications for output index design of having a normalized average consumption/average use adjustment.

1-Staff-27

Ref: Exhibit B, Tab 2

Preamble:

Dr. Makholm uses FERC Form 1 volume data in his study.

Questions:

Please respond to the following questions regarding the use of FERC Form 1 data to measure energy distributor output quantities and revenue:

a) Please confirm that FERC Form 1 volume data pertain to *sales* rather than *deliveries* and may therefore exclude unbundled deliveries where power is procured and sold to retail customers by third parties.
b) In light of the answer to a), please comment on the use of power *sales* as a measure of distributor output in the later years of the full sample period when customers of some sampled distributors switched to delivery-only service.
c) Please confirm that FERC Form 1 revenue data reflect charges for transmission services and for energy that the utility procured as well as charges for delivery services. Where distributors also transmit and supply power, please confirm that the charges for power supply can be quite large.
d) Do large industrial power customers of U.S. utilities often bypass the distribution system and take service directly from the transmission system?
e) In view of the answers to questions (b)-(d), may trends in industrial volumes have an excessively large weight in the NERA output index? If not, why not?

1-Staff-28

Ref: Exhibit B, Tab 2, p. 13

Preamble:

Dr. Makholm states:

For Ontario, as the subject was raised before the AUC in 2012, the question is whether the stretch factors applied by the OEB to the province's electricity distributors (of 0.2, 0.4 12 and 0.6) for the then-third generation PBR plan contradicts my opinion that the foundation for the stretch factor lies in the transition from cost-of-service regulation to PBR.

I conclude that it does not, in the unique context of Ontario's electricity distribution industry, because of a focus on relative productivity levels among the numerous electricity distributors as opposed to the productivity growth rates involved in the justification for applying an X-factor. My discussion and recommendations for EGD and Union deal strictly with the latter—while the OEB, for what I conclude are good reasons, has included assessments of the former for its business of regulating the prices of the electricity distributors it oversees.

Questions:

a) Please confirm that the rise or fall of X inefficiency (i.e. distance from the efficiency frontier, however defined) is a common driver of TFP growth.
b) Does Dr. Makholm believe that all firms in competitive markets have the same level of X inefficiency? How about firms in rate-regulated markets?
c) If a firm has incentives to contain costs, isn't the pace of X efficiency reduction more likely to be higher the higher is the initial level of X inefficiency?

1-Staff-29

Ref: Exhibit B, Tab 2, p. 80
Exhibit JDM-2

Preamble:

Dr. Makholm stated on p. 11 of his TFP report in the first Alberta generic PBR proceeding that:

> For the capital quantity, we measure the replacement cost of distribution plant expressed in constant dollars. One common method of measuring the replacement cost of distribution plant expressed in constant dollars is the perpetual inventory method which accounts for the presence of different vintages of capital stock at any given point in time. [footnote omitted]

Dr. Makholm stated on p. 12 of this report that:

> For the benchmark year, we compute capital quantity from the Handy-Whitman Index of Public Utility Construction ("HW"),[footnote omitted] which provides asset price indexes and the capital book value in the benchmark year. The Handy-Whitman Index numbers furnish a yardstick for fluctuations in the value of property, reflecting constant dollar

reproduction costs. Average prices and cost trends are used to develop the Handy-Whitman Index. The Handy-Whitman index is commonly used by utilities and regulators in their calculations of rate base for rate cases and in their valuations of property for insurance purposes.

The formula for calculating the value of the distribution capital stock in the benchmark year is:

$$K_{benchmark} = \frac{book\ value\ of\ utility\ plant\ in\ benchmark\ year}{\sum_{1}^{20} i \left[\frac{i}{\sum_{i=1}^{20} i} \right] HW_{1944+i}}.$$

Capital quantities after the benchmark year are given by:

$$K_t = K_{t-1} + \frac{gross\ additions\ to\ plant_t}{HW_t} - \frac{retirements_t}{HW_{t-s}},$$

where *s* is the depreciable service life of the asset.

The equation above lists two different indexes—one for additions and one for retirements. In the FERC Uniform System of Accounts, additions are added in current dollars, and retirements are subtracted according to their original dollars.

Dr. Makholm stated on p. 15 of this report that “for *s*, the asset lifetime, we use 33 years.”

Questions:

a) Since one hoss shay is assumed, please explain the rationale for dividing the book value of plant by a triangularized weighted average of past values of a construction cost index.
b) Please confirm that the one hoss shay method, unlike the geometric decay method used in many productivity studies, requires deflation of the value of *retirements* in addition to the deflation of the value of gross plant additions.
c) Please confirm that, whereas the years in which gross plant *additions* are made are known, the age of *retirements* is not.
d) Does Dr. Makholm agree that, using his methodology, the longer is the assumed average service life of assets, the lower is capital quantity growth and the faster is multifactor productivity growth? If not, why not?

e) Why is it reasonable to take a triangularized weighted average of 20 past values of the construction cost index when Dr. Makholm assumes a 33-year average service life? In the early years of the sample period, is he not then subtracting retirements from years before World War II when plant additions were assumed not to be pertinent?

1-Staff-30

Ref: Exhibit B, Tab 2, p. 74
Exhibit JDM-2
Data Request CCA-NERA-11 (f) in the first Alberta Generic PBR proceeding

Preamble:

Dr. Makholm stated on p. 4-5 of his TFP report in the first Alberta generic PBR proceeding that

> We conclude that transparency is the *sine qua non* of useful inputs to PBR plans. Thus, we document our methodology and the data used to measure TFP for each step of our analysis. Our calculations and work papers, including any adjustments to the electronic data set (for missing observations or rare but evident data anomalies) are available for inspection and assessment by other parties.

With reference to Data Request CCA-NERA-11 (f) in the first Alberta Generic PBR proceeding, Dr. Lowry asked:

> Since capital has a 60% weight in the summary input price index, is it important to make the benchmark year capital quantity calculation accurately? Why did you impute the net value of distribution plant in the benchmark year? Were data on net distribution plant value unavailable electronically or on paper? Is the calculation of a net stock benchmark quantity (K benchmark, page 12) consistent with a one hoss shay approach to capital? If not, wouldn't the use of net plant value tend to overestimate canital quantity growth and thereby slow productivity growth? Please discuss whether the benchmark year adjustment methodology is consistent with a one hoss shay method? *Please explain why a 33 year service life is assumed, but only 20 years was used when deflating net distribution plant in the benchmark year.* [italics added]

Dr. Makholm responded to this question as follows:

> Yes. A benchmark year is required for a "perpetual inventory" capital quantity measure for a population of existing utilities. The FERC Form 1 combined electronic data goes back to 1964, making that the earliest benchmark year. NERA does not know

> whether Form 1 data is readily available on paper for earlier years. The use of a benchmark year is not inconsistent with the assumption of "one hoss shay" depreciation--it merely reflects the earliest point at which deflated additions and retirements can be individually measured. NERA limited the triangularized weighted average associated with the price formula for the capital stock in 1964 to 20 years (a weighted average of the Handy Whitman indexes from 1945-64), reflecting our traditional desire to limit the analysis to post-WWII pricing and quantity data. *The 33 year service life is a more updated average of the lifetimes of utility capital.* [italics added]

Questions:

a) Please provide a full substantiation of Dr. Makholm's 33-year average service life assumption, taking particular care to explain why it would be appropriate for power distribution and gas distribution.
b) Please explain the sensitivity of Dr. Makholm's results to the service life assumption by recomputing the productivity trends using 37- and 40-year service lives. Please make sure to provide year by year results for these calculations.
c) What are the average service lives of Enbridge Gas and Union Gas?

1-Staff-31

Ref: Exhibit B, Tab 2, p. 82
Exhibit JDM-2

Preamble:

Dr. Makholm stated on p. 13 of his TFP report in the first Alberta generic PBR proceeding that:

> Data on production, transmission, general and net plant in service is required in order to determine the net distribution plant in service for the benchmark year (1964). The FERC account for distribution plant in service is for the gross (total) book value of distribution plant while for the benchmark year we require net distribution plant in service. The following methodology is used to obtain net distribution plant in service for the benchmark year (1964):

$$Net\ Distribution\ Plant = \frac{(Net\ Plant\ in\ Service) \times (Distribution\ Plant\ in\ Service)}{(Production + Transmission + Distribution + General\ Plant\ in\ Service)}.$$

> Using these data, we create a capital quantity index.

Questions:

a) Is it fair to say that Dr. Makholm's capital quantity index effectively measures quantity associated with gross plant value?
b) Why did Dr. Makholm use the value of net plant in service rather than the gross plant value for benchmark year adjustments?
c) Would the initial stock of capital have been larger if it had been calculated based on the gross plant in service?

1-Staff-32

Ref: Exhibit B, Tab 2

Preamble:

In his evidence for the applicants, Dr. Makholm measured the productivity trends of Enbridge Gas, Union Gas, and a large sample of U.S. power distributors.

Dr. Makholm presented input quantity trends by input category in his testimony in the first generic PBR proceeding before the AUC; these could be used to calculate *partial* factor productivity ("PFP") trends.

Question:

Please provide tables and figures that present year-by-year growth rates for each year of Dr. Makholm's sample period for labor, material, combined operation and maintenance ("O&M"), and capital productivity trends.

1-Staff-33

Ref: Exhibit B, Tab 2

Questions:

If Dr. Makholm determines that any revisions to his study are warranted in light of answers to data requests, please modify the analysis accordingly and provide the following:

a) a detailed description of all change(s) being made to the analysis
b) tables with updated detailed results

1-Staff-34

Ref: Exhibit B, Tab 2

Preamble:

If Amalco experiences output growth more rapid than that of U.S. energy distributors it may have opportunities to realize economies of scale.

Question:

Please project the customer, volume, and peak day send-out of Amalco during the years of the IR plan.

1-Staff-35

Ref: Exhibit B, Tab 2

Preamble:

Dr. Makholm measured the TFP trends of Enbridge Gas and Union Gas and discussed this work on pp. 25-32.

Questions:

a) What average service life assumption did Dr. Makholm use for Enbridge Gas and Union Gas? Please substantiate the assumption(s).
b) Please discuss and justify each of the inflation measures Dr. Makholm used to calculate the productivity trends of Enbridge Gas and Union Gas.
c) Please report the annual partial factor productivity growth of Enbridge Gas and Union Gas in the use of capital and O&M inputs.

1-Staff-36

Ref: Exhibit B, Tab 2

Preamble:

Dr. Makholm proposes to calibrate the X-factor of a natural gas distributor with two legacy service territories using a study of the productivity trends of U.S. *power* distributors.

Reference: Denny, M., Fuss, M., and Waverman, L., 1981. "The Measurement and Interpretation of Total Factor Productivity in Regulated Industries, with an Application to Canadian Telecommunications," in Thomas Cowing and Rodney Stevenson, eds., *Productivity Measurement in Regulated Industries*, (Academic Press, New York) pages 172-218.

Questions:

a) The OEB has, in the past, accepted use of data that can be rented from commercial vendors or are otherwise confidential in statistical research on utility industry cost. Why then are available data on gas distributor operations not preferable to power industry data as a basis for calibrating Amalco's X-factor?
b) The Denny, Fuss, and Waverman paper revealed the drivers of productivity growth to be diverse. These drivers include the pace of output growth and changes in production technology and miscellaneous other business conditions. Does Dr. Makholm agree with these general conclusions?
c) Does Dr. Makholm believe that the pace of output growth and changes in technology and miscellaneous other business conditions that drive productivity growth are the same in the power and gas distribution industries? For example, power system productivity is slowed by increased system undergrounding. What is the counterpart to this situation in gas distribution?

1-Staff-37

Ref: Information request AUC-NERA-6 (a) in Alberta's first generic PBR proceeding. 25 October 2011

Preamble:

The preamble to the AUC's question was

> The Commission notes that some of the PBR proposals submitted by the companies include special provisions for all or part of the companies' capital. In these proposals, the X factor may not be applied against capital (or depreciation) but is applied against all other expenses. [footnote omitted] In addition to the exclusion of all or some capital from the application of the I-X index, certain companies have also submitted PBR proposals that would exclude the application of X to certain non-capital expenses which would be subject to flow-through, deferral account or other forms of true-up treatment.

Question (a) was:

> Because NERA's X factor was calculated including capital expenses (see, for example, pages 11-15 of NERA's report and page 17 of the report where it is stated that the share of capital is 63.62 per cent), is the X factor that NERA has calculated the correct X factor to use for a PBR proposal that applies the X factor to only non-capital expenses or to only part of the total capital expenses?

Please explain.

NERA's response was:

> In this study, NERA has provided a long-term total factor productivity (TFP) estimate for use in AUC Proceeding 566 – Rate Regulation Initiative. NERA' s study dated December 30, 2010 does not propose the X factor as the X factor depends on additional factors such as the type of inflation factor to use in a price cap proceeding. Assuming for simplicity that NERA's total factor productivity estimate equals the X-factor, the answer to the question is no.
>
> NERA's X-factor is based on a total factor productivity study which measures changes in output vis-a-vis changes in all the firms' inputs-labor, materials and capital. When NERA's X-factor is subtracted from the inflation factor in a price cap plan it results in changes in unit costs similar to unit cost changes that firms in a competitive industry would experience. Having the price cap regime mimic the outcomes that firms in a competitive industry experience is a linchpin of performance based regulation. Applying the X-factor to only a subset of the firm's inputs can break the important link between the X-factor and changes in the firm's unit costs. Applying the X-factor to all the firms inputs provides the correct incentives for the firm to minimize its cost of production and utilize optimal amounts of labor, capital and materials. When the X- factor is applied to only a subset of inputs and the remaining inputs are regulated by some other more traditional cost of service mechanism it is less likely that the firm will make efficient input and cost minimization decisions.

Question:

The applicants are proposing an Incremental Capital Module in this proceeding like that permitted in the OEB's Rate Handbook. Does this not raise concerns like those that Dr. Makholm raised above about Amalco's cost performance incentives and the appropriateness of Dr. Makholm's TFP research for calibration of the X-factor in the proposed rate-setting plan? If not, why not?

1-Staff-38

Ref: Information request AUC-NERA-16 in Alberta's first generic PBR proceeding 25 October 2011

Preamble:

The AUC's question was:

> NERA was requested by the Commission in preparing its second report to undertake a comparison of the key provisions of the plans proposed by the utility applicants and the interveners to usual or common regulatory practices or industry standards. In its second report, NERA did not comment on the Consumers' Coalition of Alberta's (CCA) estimate of the adjustment required to NERA's TFP opening capital calculations described above. Please discuss the response above and the reasons these adjustments to NERA's TFP calculations should or should not be made.

NERA's response was:

> The CCA is mistaken in drawing a distinction between "gross" and "net" capital amounts as they would be reflected in normal utility books and records, and the CCA provided no documented support for diverging from longstanding practice in TFP growth studies using one-hoss shay depreciation. For TFP studies of these types, performed for energy utilities, telecommunication firms and in research pre-dating the advent of PBR, the starting point both for energy utilities is a stock of capital best reflective of how one would measure capital quantities with a one-hoss shay approach, given the limitations of utility rate base accounting (which is not there to track capital quantities but rather to reflect, from a wider legal and accounting perspective, the obligation of ratepayers to investors for the capital placed in the public service).
>
> Realizing those data limitations, it is the longstanding custom in empirical TFP growth studies to use the net book value, discounted by the "triangularized" weighting method shown on page 12 of NERA's First Report dated December 30, 2010, to convert that into a capital stock measure closest to what we would determine if we had been able to perform our one-hoss shay method further back in time. Such was the method accepted for Dr. Makholm's doctoral dissertation in 1986 and at the Federal Communications Commission in the 1990s (sections documenting both are attached), and in the other NERA TFP growth studies.
>
> Book depreciation (designed to focus on utility property and the compact between ratepayers and investors) and one-hoss shay depreciation (designed to elicit reliable

capital quantities for TFP growth studies) are two different things. But in a search for a reliable starting point for a capital stock, the method NERA used in this case is built on solid and reliable precedent, and NERA does not propose to diverge from those practices in this case.

Questions:

a) Please provide examples, other than reports prepared by NERA, where the benchmark year adjustment in a productivity study using a one hoss shay capital treatment used net plant value in the benchmark year adjustment for the capital quantity index. Does Dr. Makholm believe that this practice is more the rule than the exception amongst other practitioners?
b) Why is it reasonable to base the benchmark year quantity on net plant value and in the following year subtract all retirements that were previously part of gross plant value?
c) In view of the fact that, even in years shortly after the benchmark year, Dr. Makholm subtracts the estimated full quantity of retirements from investments over the last 33 years from the capital quantity index, please explain why net plant value makes more sense than gross plant value for a benchmark year adjustment in the one hoss shay context.

1-Staff-39

Ref: Exhibit B, Tab 1, p. 10

Questions:

a) Please confirm whether the applicants' intend to complete the current six year DSM periods separately.
b) Please confirm whether the applicants' intend to merge the two DSM portfolios after that.
c) Does the answer to b) depend on the outcome of DSM mid-term review?

2-Staff-1

Ref: Exhibit B, Tab 1, p. 9

Preamble:

The application states that both Enbridge Gas and Union Gas have refinanced virtually all of their existing long-term debt based on historically low interest rates that have existed over the past 10 years. Amalco will be required to refinance approximately 50% of its existing long-term debt during the deferred rebasing period. Higher interest rates combined with refinancing a significant portion of existing long-term debt could put significant pressure on Amalco's earnings.

Questions:

a) When do the applicants expect Amalco to start refinancing its existing long-term debt?
b) Will the new debt instruments be issued by Enbridge Inc. or individually by Union Gas and Enbridge Gas?
c) What is the expected differential in interest rates between the new debt expected to be issued and the maturing instruments?
d) Please provide evidence of the future increase in interest rates referred to in the evidence and the expected increase over the deferred rebasing period.
e) What is the expected increase in costs as a result of issuing the new debt?

2-Staff-2

Ref: Exhibit B, Tab 1, p. 14

Preamble:

The application notes that the capital investment required to grow and maintain safe and reliable service to customers on the transmission and distribution systems is supported by Enbridge Gas and Union Gas' Asset Management Plans. These plans were generated prior to the proposal to amalgamate the utilities. While there are some differences, each 10-year plan and associated processes support the long-term optimization of asset investments to balance cost, risk and performance. Management expects to integrate Enbridge Gas and Union Gas into a single set of asset management processes and software during the deferred rebasing period.

Questions:

a) Please provide the individual Asset Management Plan of Enbridge Gas and Union Gas. In case a final draft was not prepared, please provide the working draft of the two Asset Management Plans.
b) Please explain how the 10-year plan and associated processes will support the long-term optimization of asset investments. Does the optimization take into account the joint assets of Enbridge Gas and Union Gas?
c) What is the estimated timeline to integrate Enbridge Gas and Union Gas into a single set of asset management process and software?

2-Staff-3

Ref: Exhibit B, Tab 1, p. 30

Preamble:

In its evidence, the applicants state that Amalco will report under US GAAP financial standards. During the deferred rebasing period Amalco expects to change accounting practices and processed as part of the implementation of an integrated accounting system. One of the examples provided is the calculation of depreciation expense. Enbridge calculates depreciation expense using a monthly average approach and Union Gas uses the mid-year average approach. Amalco will adopt a common approach.

Questions:

a) What common approach will Amalco adopt?
b) Has the process of integration been initiate and what is the expected timeline of full integration?
c) Is it possible to quantify the impact that this new aligned depreciation policy would have on Amalco? If yes, please compare it to the current depreciation expense in rates for both Enbridge Gas and Union Gas.

5-Staff-1

Ref: Exhibit B, Tab 1, Attachment 4

Preamble:

The applicants provided a list of deferral accounts to be continued during the deferred rebasing period at Exhibit B, Tab 1, Attachment 4.

Questions:

a) Please confirm that for all of the deferral and variance accounts that the applicants propose be continued there are no proposed changes to the description or operation of the accounts.
b) Please explain why Enbridge Gas' Manufactured Gas Plant Deferral Account continues to be required during the deferred rebasing period. Please also provide the current balance in this account.
c) With respect to Enbridge Gas' Dawn Access Costs Deferral Account, please provide the expected total cost of the implementation of the Dawn Transportation Service. Please also provide the expected revenue requirement impact of the implementation costs for each year of the deferred rebasing period.
d) Please advise when Union Gas' North Purchased Gas Variance Account (PGVA) is expected to be closed.

10-Staff-1

Ref: Exhibit B, Tab 1, p. 30

Preamble:

In its evidence, the applicants state that Amalco will report under US GAAP financial standards. During the deferred rebasing period Amalco expects to change accounting practices and processed as part of the implementation of an integrated accounting system.

In March 2017 the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) 2017-07 which impacts the accounting for pensions and OPEB costs effective January 1, 2018. This accounting standard update limits the amount of pension and OPEB costs that a utility is permitted to capitalize under US GAAP.

Questions:

a) Given that both Enbridge Gas and Union Gas recover their pension costs on a US GAAP (accrual) basis, has the impact of this change been reflected in its estimated 2019 revenue requirement for purposes of determining rates under the rate setting mechanism for the deferred rebasing period, effective January 1, 2019?
b) If not, please quantify the impact it is expected to have on the 2019 revenue requirement.
c) If this accounting standard change does not impact the 2019 revenue requirement (or is not applicable to either Union Gas or Enbridge Gas), please provide reasons.
d) Are there any other material changes to accounting practices / policies that have been identified since the filing of this application? If so, please explain each change in detail.
e) Do the applicants intend to merge the current Enbridge Gas and Union Gas pension plans under Amalco? Please explain.

12-Staff-1

Ref: Exhibit B, Tab 1, p. 41

Question:

Do the applicants foresee a time when the three rate zones (EGD, Union North and Union South) would be harmonized into a single rate zone? Please explain.

13-Staff-1

Ref: Exhibit B, Tab 1, p. 26
Exhibit B, Tab 1, pp. 30-31
Exhibit B, Tab 1, Attachment 5

Preamble:

The applicants listed the OEB directives that it proposed to address during the deferred rebasing period at Exhibit B, Tab 1, p. 31.

At Exhibit B, Tab 1, Attachment 5, the applicants list the directives that they intend to address as part of the 2029 rebasing.

Questions:

a) Enbridge Gas listed no directives that it would respond to during the deferred rebasing period. Please advise why Enbridge Gas does not intend to respond to the following directives during the deferred rebasing period:

   i. Reporting on Unaccounted for Gas (UAF) (p. 12 of EB-2017-0086 Settlement Agreement).
   ii. Analysis setting out need and justification before Enbridge Gas develops or acquires incremental storage (p. 15 of EB-2016-0142 Settlement Agreement).
   iii. A study on best practices for the true-up of AU between forecast and actual (p. 9 of EB-2017-0102 Settlement Agreement).

b) One of the directives that Union Gas intends to address during the deferred rebasing period is to file a study assessing the continued appropriateness of its methodology for determining NAC. Please explain why Enbridge Gas would not also agree to file a study reviewing its AU forecasting methodology during the deferred rebasing period.

c) At Exhibit B / Tab 1 / p. 26, Amalco noted that it may make certain cost allocation or rate design proposals as part of its annual update filings. In the list of OEB directives that Amalco proposes to address at the 2029 rebasing, three of the Union Gas directives (numbered 1-3), are cost allocation and rate design issues that Union Gas was previously directed to review. If the OEB were to consider cost allocation and rate design changes in this proceeding, please explain why the noted three directives could not be addressed in the 2019 rates proceeding.

13-Staff-2

Ref: Exhibit B, Tab 1, Attachment 5, pp. 2-3

Preamble:

The applicants note on p.1 that Enbridge Gas' <u>2014-2018 CIR Decision Directives</u> include the following:

a. Commitment to develop a benchmarking study attempting to address both capital & operating costs and hold consultation with stakeholders. OEB expects benchmarking work to be supported by independent expert opinion to be filed upon rebasing.

The applicants state on page 2 that Union Gas' 2014 to 2018 Incentive Regulation Mechanism Settlement Agreement (EB-2013-0202) has the following commitment:

a. Union agreed (subject to any subsequent agreement of all parties to extend the IRM term) to prepare a full cost-of-service filing at the time of rebasing, regardless of whether Union applies to set rates for 2019 on a cost-of-service basis or not.

Question:

How is the proposed rate-setting plan consistent with these commitments?

13-Staff-3

Ref: Decision and Order, Fenelon Falls Project, EB-2017-0147

Preamble:

As part of this decision, the OEB approved Enbridge Gas' proposed definition of a Community Expansion Project. The OEB also approved a surcharge in the form of a rate rider in the amount of \$0.23 per m^3 to be applied to all new customers of future Enbridge Community Expansion Projects.

Question:

Do the applicants anticipate that the decision in the Fenelon Falls Project will apply to future Amalco projects? Please explain.

14-Staff-1

Ref: Exhibit B, Tab 1, p. 20

Preamble:

The applicants have proposed a scorecard to measure and monitor performance during the deferred rebasing period. The proposed scorecard is modelled after the electricity distributors' scorecard and includes measures for customer focus, operational effectiveness, public policy responsiveness and financial performance.

Questions:

a) Please provide results using the metrics in the proposed scorecard for the years 2013-2017 (inclusive).
b) Do the applicants propose to provide separate scorecards for the different rate zones or would it be a single scorecard covering the amalgamated utility?

14-Staff-2

Ref: Exhibit B, Tab 1, p. 26

Preamble:

The applicants have committed to file the following information annually:

1) An application for approval of any Z-factor adjustments, the pricing of any new regulated services or cost allocation and rate design proposals for which advance approval from the OEB is required in a timeframe that would enable these issues to be resolved in sufficient time to be reflected prospectively in the next year's rates;

2) A draft rate order for EGD, Union North and Union South rate zones filed by September 30 which reflects the impact of the PCI, Y factors, approved Z factors and normalized average consumption/average use;

3) The supporting documentation for any ICM requests that are not examined as part of a leave to construct application earlier than September 30;

4) An application for the disposition of actual year-end non-commodity deferral account balances as soon as reasonably possible following the public release of annual audited financial statements.

Questions:

a) In the situation where there are no requests for a Z-factor adjustment, pricing of new regulated services, cost allocation or rate design proposals, or ICM treatment:

   i. Please confirm that the annual rate adjustment application would be filed by September 30 based on the applicants' proposal.
   ii. If so, please explain why the application could not be filed earlier in the year.
   iii. Please advise whether Amalco could file earlier in the year if Q1 inflation information is used (as opposed to Q2 information).

b) In the situation where there is a request for a Z-factor adjustment, pricing of new regulated services, cost allocation or rate design proposals, or ICM treatment:

   i. Please confirm that the evidence supporting the core IRM adjustments (PCI, Y-factors, NAC / AU) would still only be filed by September 30 based on the applicants' proposal.

c) Please advise whether the request for approval of non-commodity deferral account disposition is planned to be filed as a standalone application. Please provide details regarding the timing of the filing of such a request. Please also advise whether Amalco intends to file separate applications to dispose of Union Gas' deferral accounts and Enbridge Gas' deferral accounts.

16-Staff-1

Ref: Exhibit B, Tab 1, p. 27

Preamble:

In the evidence, the applicants document a proposal to conduct a stakeholder meeting every two years to discuss financial and operational performance, capital plans, any forthcoming ICMs, etc.

The proposed stakeholder meeting is not part of a regulatory process before the OEB or subject to any approval or other determination by the OEB. It is also not clear how the applicants' historical performance data or forecasts will be tested through the proposed stakeholder meeting.

Question:

Please provide further details on the intent of the stakeholder meeting, its operation, and how results and proposals will be integrated with the regulatory rate-setting process (i.e., through rate applications during the "stay-out" period or at the time of rebasing) or through other applications, to communicate these results and proposals to the OEB and seek OEB approval, where necessary.