EB-2017-0306/7

ENBRIDGE/UNION MAADS/RATES

SEC CROSS-EXAMINATION MATERIALS

VOLUME 1

conditional upon a satisfactory regulatory
decision..."

Has your board of directors -- or have the respective boards of directors --

(Reporter appeals)

MR. MILLAR: Go ahead, Jay.

MR. SHEPHERD: So this last bullet, I want to make sure I understand because this references several places.

Have your boards of directors actually approved the amalgamation of these two companies?

MR. KITCHEN: I would say the board of directors has approved us proceeding with the application and the amalgamation, should we get a satisfactory regulatory decision.

MR. SHEPHERD: Does that mean that if the OEB doesn't give you the decision you've asked for, then you just won't merge? Is that --

MR. KITCHEN: That's --

MR. SHEPHERD: -- or that that's possible?

MR. KITCHEN: I don't think that's what we're saying. What we're saying is that there are a number of things that we've asked for as part of this application, and to the extent that the Board deviates from those requests, we'll need to examine that decision and the reasons for the decision and decide whether or not we proceed with amalgamation.

MR. SHEPHERD: If the Board were to say, as a number of intervenors will be proposing, that you're given permission to amalgamate but you have to come in for a custom IR in 2020, do you believe that you then are in a position where you can say, well, then we're not going to amalgamate?

MR. KITCHEN: I'm not in a position to say that today. I think it would be very hard for the board of directors to approve amalgamation under those conditions. But again, you need to look at the whole decision.

MR. SHEPHERD: So normally the Ontario Energy Board won't consider an application to amalgamate unless it has already been approved. And I'm not sure I have ever seen the Board presented with a proposal to amalgamate only if they get a decision they like -- the application -- they get a decision they like. Is there a precedent you can put us to that would help us?

MR. CASS: No, Jay, there is not. I just wanted to characterize somewhat differently what you've said.

I don't think the applicants are saying they're looking for a decision they like. The applicants are saying that when they get the decision, if the parameters under which they would need to operate cause them to think it would be imprudent to proceed, they can't commit in advance to doing something that may at a later time appear to be not a prudent course of action.

MR. SHEPHERD: So you're suggesting that the Board might make a decision that's imprudent?

MR. CASS: No, I'm suggesting that the parameters created by the Board around the amalgamation might be such that the applicants decide it's not prudent to proceed in the way that they've proposed in this proceeding.

MR. SHEPHERD: Am I right then that the only way that you would not proceed is if the Board -- the Board's decision would require an imprudent course of action? Is that right?

MR. CASS: Jay, I think the answer has been given that the decision will be looked at the time for the board of directors to make an assessment as to whether they can proceed in the manner that they've proposed. The entire decision will have to be looked at and considered.

MR. SHEPHERD: Thank you.

MR. QUINN: Can I interrupt? Sorry, Jay. I just got an email from Linda Wainewright saying they can't hear on the phone.

MR. MILLAR: We'll take care of that.

MR. SHEPHERD: On the next page, page 3 of that material, they ended hundred strategic rationale but the first bullet refers to a 2017 strategic planning session. What was the date of that session?

MR. REINISCH: So I do not have the specific date of the meeting that took place, the planning session, but I believe it did take place in September of 2017.

MR. SHEPHERD: That's interesting, because one of these attachments is a integration memo on July 25th. So the strategic planning session was after that memo?

MR. REINISCH: The strategic planning session referenced in the Board material is an Enbridge Inc.

ENBRIDGE GAS DISTRIBUTION INC. AND UNION GAS LIMITED

Undertaking of Mr. Reinisch
To Mr. Shepherd

REF: Tr.1, p.81

Please provide updated S&P or DBRS reports or ratings since they learned of this application.

Response:

Please see Attachment 1 for the February 14, 2018 DBRS rating report for Union. The September 20, 2017 DBRS rating report was provided in the response to SEC Interrogatory #20 found at Exhibit C.SEC.20. The Applicants have not received approval from S&P to provide its reports.

Rating Report

Union Gas Limited

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DBRS

Insight beyond the rating.

Ratings

Debt	Rating	Rating Action	Trend
Issuer Rating	A	Confirmed	Stable
Unsecured Debentures/Medium-Term Note Debentures	A	Confirmed	Stable
Commercial Paper	R-1 (low)	Confirmed	Stable
Cumulative Redeemable Preferred Shares	Pfd-2	Confirmed	Stable

Rating Update

On February 7, 2018, DBRS Limited (DBRS) confirmed the Issuer Rating and Unsecured Debentures/Medium-Term Note Debentures rating of Union Gas Limited (Union or the Company) at "A," the Company's Commercial Paper rating at R-1 (low) and its Cumulative Redeemable Preferred Shares rating at Pfd-2. All trends are Stable. The rating confirmations largely reflect Union's relatively low-risk gas distribution business, which operates under a supportive regulatory framework in an economically stable service territory with a large and growing customer base.

DBRS rates Union on a stand-alone basis and does not assume any credit support from its ultimate parent, Enbridge Inc. (Enbridge; rated BBB (high), Stable by DBRS). On November 2, 2017, Union and Enbridge Gas Distribution Inc. (EGD; rated "A," Stable by DBRS) filed a Mergers, Acquisitions, Amalgamation and Divestitures application with the Ontario Energy Board (OEB) to amalgamate. Enbridge expects the regulatory review to take the better part of 2018. Enbridge will seek approval from its Board of Directors to proceed with the amalgamation based on an assessment of the final regulatory approvals from the OEB, which is anticipated to take place in Q3 2018. Should the amalgamation not proceed, Union will file a new five-year incentive regulation (IR) framework application for 2019, and beyond. DBRS will continue to monitor the progress of the application as more information becomes available.

DBRS's assessment of the Company's business risk considers the supportive cost of service (COS)-based regulatory framework in Ontario, which provides a vast majority of Union's earnings. The Company has operated under an IR framework from 2014 to 2018, which allowed for a return on equity (ROE) of 8.93% and provided predictable cash flows. Natural gas supply costs are passed through to customers, mitigating commodity price risk, with annual rate escalation indexed at 40% of inflation. Major capital expenditures (capex) are pre-approved by the OEB for inclusion in rates as projects are completed and placed in service. DBRS notes that, although the Company's regulated distribution and storage business accounts for the bulk of Union's earnings, earnings generated from its unregulated storage business (approximately 12% of EBITDA in 2017) could expose the Company to some earnings volatility. DBRS views this segment as higher risk than the regulated distribution and storage business because of the impact of seasonality on storage demand and rates.

Continued on P.2

Financial Information

	9 mos. ended Sep. 30		12 mos. ended Sep. 30	12 mos. ended Dec. 31				
	2017	**2016**	**2017**	**2016**	**2015**	**2014**	**2013**	**2012**
Cash flow/debt	10.7%	11.9%	10.8%	11.3%	11.0%	13.4%	14.4%	14.0%
Lease-adjusted debt/capital	66.5%	66.3%	66.5%	67.1%	65.8%	65.8%	65.1%	64.2%
EBIT interest coverage (times)	2.26	2.38	2.17	2.24	2.27	2.43	2.48	2.35

Issuer Description

Union is a utility that provides natural gas distribution, transmission and storage services in Southwestern, Northern and Eastern Ontario, serving approximately 1.5 million customers. Union's common stock is held by Great Lakes Basin Energy L.P., a wholly owned limited partnership of Westcoast Energy Inc. (Westcoast; rated A (low), Stable by DBRS). Westcoast is indirectly owned by its ultimate parent, Enbridge.

Earnings and Outlook

	9 mos. ended Sep. 30		12 mos. ended Sep. 30	12 mos. ended Dec. 31				
($ millions, where applicable)	**2017**	**2016**	**2017**	**2016**	**2015**	**2014**	**2013**	**2012**
Gas distribution margin	599	585	826	812	800	778	772	727
Storage and transportation revenues	246	206	318	278	239	266	252	269
Ancillary revenue	13	12	22	21	26	21	26	28
Operating revenue	858	803	1,166	1,111	1,065	1,065	1,050	1,024
Operating expenses	(371)	(339)	(516)	(484)	(468)	(465)	(464)	(445)
EBITDA	487	464	650	627	597	600	586	579
Depreciation and amortization	(200)	(181)	(258)	(239)	(224)	(212)	(204)	(213)
EBIT	287	283	392	388	373	388	382	366
Gross interest expense	(127)	(119)	(181)	(173)	(164)	(160)	(154)	(156)
Earning before taxes	160	164	223	227	216	232	228	210
Core net income	155	152	209	206	188	196	191	170
Reported net income	155	152	208	205	188	195	207	170
Return on common equity	11.4%	12.6%	11.6%	12.7%	13.0%	14.6%	15.5%	14.8%
Distribution rate base 1	n/a	n/a	n/a	4,758	4,228	3,976	3,784	3,570

1 n/a: not available on a quarterly basis.

Summary

- Approximately 88% of Union's EBITDA is generated from its regulated gas distribution, storage and transmission businesses. The balance is generated from the Company's unregulated storage business, which carries some earnings volatility resulting from seasonal fluctuation in demand and rates.
- The Company's EBITDA increased in 2016 primarily as a result of an increase in transportation revenue from the 2015 Dawn-Parkway Expansion project and higher storage pricing.
- For 9M 2017, the Company's EBITDA was marginally higher as it benefitted from additional revenue from the 2016 Dawn-Parkway Expansion and Burlington-Oakville pipeline projects. Earnings before interest and taxes (EBIT) remained relatively unchanged as the increase in operating revenue was largely offset by an increase in depreciation expense from projects placed into service.

Outlook 2018

- DBRS anticipates that Union's earnings will likely improve modestly in the near term as a result of customer growth and higher storage and transportation revenue from major capital projects placed in service H2 2017.
- Barring the impact of unpredictable weather conditions, DBRS expects ongoing energy conservation programs, including the Company's Demand Side Management Initiative, to have a modest impact on customer usage. However, any impact on earnings is mitigated through the regulatory framework. Furthermore, the Company expects modest annual customer growth of approximately 1% to 2%.

ENBRIDGE GAS DISTRIBUTION INC. AND UNION GAS LIMITED

Undertaking of Mr. Kitchen
To Mr. Garner

REF: Tr.1 p.23.

Please advise whether any meetings with the OEB Board Chair took place outside of the Board's office.

Response:

One of the meetings between the OEB Board Chair, OEB Chief Operating Officer & General Counsel and Enbridge Executive Management was held at the Union Gas 777 Bay St. office.

ENBRIDGE GAS DISTRIBUTION INC. AND UNION GAS LIMITED

Answer to Interrogatory from
Consumers Council of Canada ("CCC")

MAADs Application

Reference: No-Harm Test

Question:
From Enbridge Inc.'s perspective what are the primary objectives of the merger? Under what circumstances would Enbridge Inc. not proceed with the merger? If the OEB reduced the rebasing deferral period to five years would the merger proceed?

Response

The primary objectives of the merger are to deliver benefits and value to both customers and the Amalco while continuing to provide safe and reliable service. It is not possible at this time to speculate on the circumstances under which Amalco may not proceed with the amalgamation.

However, if the OEB reduced the rebasing deferral period to five years, management would be unable to proceed with the amalgamation as proposed and outlined in the evidence. Also, see the response to Board Staff Interrogatory #4 found at Exhibit C.STAFF.4.

ENBRIDGE GAS DISTRIBUTION INC. AND UNION GAS LIMITED

Answer to Interrogatory from
Ontario Energy Board Staff ("Staff")

MAADs Issues List – Issue No. 2

Reference: 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:

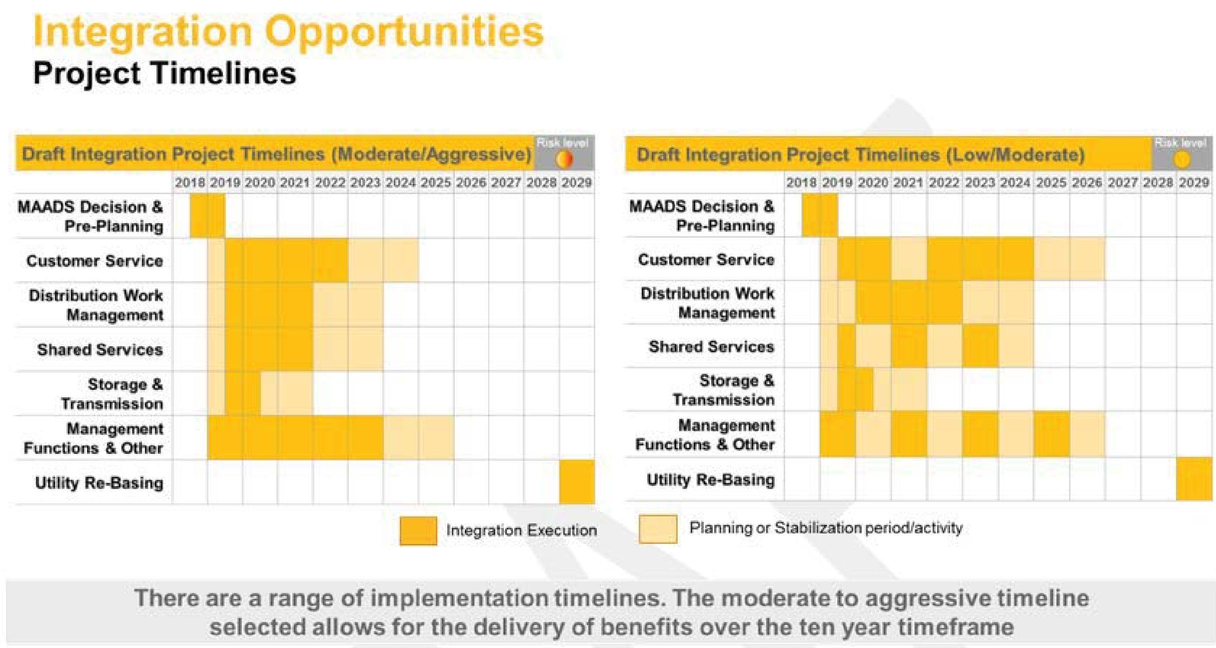
a) Proceed with the amalgamation
b) Propose a Price Cap IR methodology to set rates from 2019 to 2024.

Response

The intent of the Board's MAADs framework and policy is to incent efficiencies that ultimately benefit customers. The proposed amalgamation of EGD and Union is a significant undertaking. The degree of integration is highly dependent on the term. The Applicants have selected a term of 10 years in order to make deep, meaningful and lasting improvements. The quantity and complexity of the Information Technology and related process changes required to support efficiencies requires a considerable timeline to allow for investigation, design, costing, implementation and testing such that Amalco is able to continue to provide safe, reliable service to its customers. Amalco will need to make significant upfront investments and requires sufficient time to economically justify the investments and realize the benefits of the efficiencies prior to rebasing.

A term less than 10 years will not provide Amalco sufficient incentive and time to pursue the breadth of the proposed integration activities. The suggested term of five years would likely result in very little integration. Management's own high level estimate of integration project timelines shown in response to BOMA Interrogatory #16 (d) (i), Attachment 1 found at Exhibit

C.BOMA.16 and reproduced below shows that even an aggressive schedule extends integration beyond the five year mark of the 10 year deferred rebasing period. Given the number and size of integration initiatives being undertaken over the 10 year period, the 10 deferred rebasing period is key to achieving the full potential of integration activities in a balanced manner, while delivering quality within a reasonably paced timeline. As such, the amalgamation could not proceed as outlined with a term of five years.



Over the course of the 10 year deferred rebasing period, Amalco is forecasted to achieve on average 20 bps above the forecast allowed Return on Equity (ROE) as shown on slide 23 of the presentation provided in response to FRPO Interrogatory #1, Attachment 1 found at Exhibit C.FRPO.1, and summarized below.

	Proposed Filing: 10 year MAADS (Escalated Price Cap + Incremental Capital Module)									
	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Achieved ROE	9.2%	9.5%	9.4%	9.4%	9.4%	9.5%	9.5%	9.7%	9.7%	9.6%
Allowed ROE	9.2%	9.3%	9.4%	9.4%	9.4%	9.4%	9.4%	9.4%	9.4%	9.4%

Included in the forecasted 20 bps are “unidentified efficiencies” as provided in EB-2017-0306 Exhibit B, Tab 1, Attachment 12. These unidentified efficiencies represent additional savings that Amalco will need to find in those specific early years of the 10 year deferred rebasing period so that Amalco will achieve a ROE that approximately equals the forecasted allowed ROE for that year. The unidentified efficiencies were included to recognize that all efficiencies cannot be identified today with precision and Amalco will need to undertake additional efforts and related savings to those estimated in Attachment 12 in order for the utility to achieve that year's forecasted allowed ROE.

In its Rate Handbook at p.28, the Board stated:

> While an earnings sharing mechanism protects customers from excess earnings, it can diminish the incentives for a utility to improve their productivity, and any benefits to customers are deferred.

The example of an ESM that begins in year one will give Amalco less incentive to achieve the maximum savings for ratepayers upon rebasing while taking on the risk of integration. An ESM needs to ensure no disincentive to pursue productivity savings. As such, the ESM as proposed for Amalco in the last 5 years of the 10 year deferred rebasing period would provide the proper incentive for Amalco while enabling ratepayers to benefit in the event of utility earnings in excess of 300 bps above allowed ROE.

As stated at EB-2017-0306, Exhibit B, Tab 1, pages 14 to 15, the OEB's Decision in this proceeding must be assessed by the board of directors of Enbridge Inc. and the boards of directors of EGD and Union. The boards of directors must ensure that any upfront investments are justified and prudent based on the synergies to be realized over the deferred rebasing period, prior to determining whether to proceed with the amalgamation.

without amalgamating?

MR. KITCHEN: Just as we haven't done any detailed planning around the costs of the integration or the benefits, we have not looked at how we could possibly bring together the companies in a different way than amalgamation.

Our proposal is to amalgamate, and to amalgamate under MAADs, defer rebasing for ten years, and in those ten years incur costs, get benefits, and pass those back to ratepayers, so I'm not going to speculate, I guess is what I'm saying, on what functions might work in a shared-service world or an affiliate world when our proposal is not to do that.

MR. SHEPHERD: That's why I was pursuing this, Mr. Kitchen, is when you presented it to your board, you present it to them as, we can save $680 million if we amalgamate and we can save zero, the status quo is you save zero, if we don't amalgamate. That's binary, and that's what I'm asking about, because that's not correct, is it?

MR. CASS: What is the question then?

MR. SHEPHERD: The question is if you present to your board, we can save 680 if we amalgamate, we can save zero, the status quo is zero if we don't amalgamate, that's not true, is it?

MR. KITCHEN: I don't think that's what we told the board.

MR. SHEPHERD: Okay.

MR. KITCHEN: What we did is we said that we will need

-- we will come back to you once we have a decision from the OEB and we will bring that back and we will assess whether or not we can proceed with the amalgamation in the way that we intend. If we can't, then we won't, but -- and then at that point, that sets off a whole other round of what we might do, and we haven't turned our mind to that, and we won't turn our mind to it until we actually have a Board decision and make our decision as to whether we proceed.

MR. SHEPHERD: Fair point, and that's really -- if I can bring this right to a conclusion, this particular issue, that's really what I was trying to get at, is you don't want to give the Board the impression that our -- Ontario Energy Board the impression that there is $680 million of efficiencies available only if you amalgamate, because that wouldn't be true, would it? That there is $680 million of efficiencies, some of which you would get if they said, no, you have to come for a custom IR. True? It's a yes/no question.

MR. CULBERT: Well, to Mr. Kitchen's point, we don't know what the different level of savings may or may not be in a different application to the Board, and it's lost on me why the Board would want to entertain a model which, in everybody's view, would have a different level, lower level, of savings over a ten-year term than the model we've proposed. It's lost on me.

MR. SHEPHERD: The -- I have just a couple of other questions on savings.

actually four basis points on the upside and 200 basis points on the downside.

MR. REINISCH: Sorry, 200 basis points?

MR. SHEPHERD: That's what you have on page 31. Actually, 210 basis points, isn't it?

MR. REINISCH: So we had FRPO 3 addresses the synergies. There are a number of other risks that we've identified that go into slide 31.

MR. SHEPHERD: Thank you.

MR. QUINN: Okay, if we can turn up page 27, please.

Now, just to summarize what I'm reading here -- you can tell me if I'm wrong -- if for whatever reason the productivity factor is too high, the utilities would pull the application and apply for custom IR in 2020? Is that a fair summary?

MR. KITCHEN: I think it would -- I can't -- the bullet says that we would remove the request to seek an extension of the current IR models with the intention of a new custom IR in 2020, but before we would actually do that we would have to make an assessment of whether or not that, in combination with the other parameters that the Board finds on, whether or not we'd actually make that decision to pull the application.

MR. QUINN: So I take it from your answer, Mr. Kitchen, there is no report or analysis that has considered this option for management's consideration?

MR. KITCHEN: No.

MR. SHEPHERD: Sorry to interrupt, Dwayne, but I asked you questions about this earlier and you didn't talk about pulling the application. If the Board makes a decision, you can't pull the application; right? You're done, so you can just decide not to proceed with the amalgamation.

MR. KITCHEN: Yes, you're correct.

MR. SHEPHERD: Okay. Sorry, I was just confused.

MR. KITCHEN: Sorry, I think I was responding to Dwayne's question, which I thought said pull the application, but you are correct.

MR. QUINN: Well, it says "remove request for PCRMM and seek extension for custom IR models". The vernacular I used was "pull the application", which the answer to Mr. Shepherd is you would stop the amalgamation and go down parallel paths for custom IRs for the two respective utilities?

MR. KITCHEN: That's the potential. But again, it won't happen until we've actually got the Board's decision and we've had an opportunity to review the decision and the findings and the reasons.

MR. QUINN: I think Mr. Shepherd asked about -- I think we'll turn it up anyway. Page 33. I think I understood your answer, but I just -- you said that:

> "Management will return to the Board if the terms vary based upon discussions with the OEB."

I didn't interrupt him at that time, but what terms would expected to have varied sufficient that you would go back to the board? Like, what terms are you referring to?

MR. KITCHEN: I don't think there was any expectation

ENBRIDGE GAS DISTRIBUTION INC. AND UNION GAS LIMITED

Undertaking of Mr. Reinisch
To Mr. Shepherd

REF: Tr.1, p.67

Please provide a list of steps that have already been implemented to rationalize activities between the two utilities.

Response:

The following table outlines changes (if any) that have been implemented to rationalize activities between the two utilities.

Area	**Changes (if any)**
Business Development	No steps have been implemented to rationalize activities between the two utilities.
Customer Care	No steps have been implemented to rationalize activities between the two utilities.
Distribution Operations	No steps have been implemented to rationalize activities between the two utilities.
Engineering	No steps have been implemented to rationalize activities between the two utilities.
Enterprise Safety & Operational Reliability	These functions continue to operate separately. Presently the two utilities continue to work with the enterprise strategy for broader alignment with any charges occurring through the affiliate relationship code as required.
Finance	The finance departments at both Union and EGD are under common leadership. Additionally the accounting and O&M groups are under common leadership. These leaders manage distinct departments that provide respective services to each utility. The costs associated with the centralized leadership position are charged to each of Union Gas and EGD as per affiliate relationship code requirements.
Gas Control	No steps have been implemented to rationalize activities between the two utilities.

Area	Changes (if any)
Human Resources	Leadership of both Union Gas and EGD HR Business Partner function has centralized under one common leader. The costs associated with the centralized position are charged to each of Union Gas and EGD as per affiliate relationship code requirements. None of the two utilities Business Partner teams have been rationalized. The two utilities operate separate HR systems and teams.
Information Technology	Both Union Gas and EGD have separate IT support teams that provided project implementation and application support services. There have not been any steps taken to rationalize these functions given the distinctly different set of software and inherent need for unique skills and knowledge that distinct software necessitates.
Public Affairs	No steps have been implemented to rationalize activities between the two utilities.
Real Estate Services	This is a shared service within the larger enterprise and cost are allocated based on the work for each utility
Regulatory	No steps have been implemented to rationalize activities between the two utilities.
Sales	No steps have been implemented to rationalize activities between the two utilities.
Storage and Transmission	No steps have been implemented to rationalize the regulated storage and transmission activities between the two utilities. The unregulated business in both utilities is rationalizing efforts and all work that occurs is charged directly to the unregulated business.
Supply Chain Management	No steps have been implemented to rationalize activities between the two utilities. Supply Chain groups at both EGD and Union Gas are leveraging common standards and strategies with the larger enterprise.

costs.

MR. SHEPHERD: Now, given that you're planning to spend $12 billion in capital over the next ten years, I would have thought that at least somebody would have looked at whether there is some way to save some money if you integrate. Has anybody done that? Whether preliminary or otherwise, has anybody taken a look at that yet?

MR. CULBERT: No, the crux of most of our evidence is until we know what the new structure will look like, including all levels of an organization, there is no way at this point in time to look at the aspects of the Union asset management plan and EGD's asset management plan and how they would be or could be looked at in a singular view, so we haven't got any analysis of that sort.

MR. KITCHEN: What we do have is the high-level planning that we've done around integration of systems and processes, and we've provided those in our evidence and described them in more detail in BOMA 16.

MR. SHEPHERD: But those are actually largely incremental costs, capital costs, to integrate; right?

MR. KITCHEN: They are.

MR. SHEPHERD: But presumably, there are some incremental savings as well because you have a different configuration of your system now.

MR. KITCHEN: And there may very well be, but that work has not been done.

MR. SHEPHERD: All right. Is it fair to assume that it will be greater than zero?

MR. KITCHEN: It will be something. So probably yes, greater than zero. But again, as we move through the deferred rebasing period, any savings that we are able to achieve as a result of the amalgamation ultimately flows to ratepayers and they also get the savings through the interface of systems and to the extent that there are other savings, they will get those, too, eventually.

MR. SHEPHERD: Okay, all right.

MR. CULBERT: As we complete an overall asset management plan, it will determine the view of the necessary capital each and every year. And we're going to be doing a rolling asset management plan, I'll say recalibration every year. But until such time as we have one individual plan, the concept of there will be savings, savings compared to what? Two individual plans which were being run by separate entities? I suppose, but not sure that's really worth anything to relative to what the individual plan might be.

MR. SHEPHERD: Well, you have a forecast of your capital spend.

MR. CULBERT: We do, as individual entities.

MR. SHEPHERD: And that's two separate companies, right?

MR. CULBERT: Yes.

MR. SHEPHERD: So you do not yet have a forecast -- let me understand this. You have forecasts on status quo basis and on an integrated basis in this presentation, right, for over all revenues? And you're assuming, in all

your calculations in those forecasts, that your capital
plan is identical in both cases, right?
     MR. CULBERT: We're assuming at this point in time
that that's our view of capital requirements right now.
     MR. SHEPHERD: The only delta -- aside from the rate-
setting mechanism, the only delta is the OM&A savings and
the things that flow out of it?
     MR. REINISCH: So the delta is both the O&M savings
and as well as the capital costs required to achieve
those --
     MR. SHEPHERD: The investments to get there, yes. 172
investment to get there and 680 saved, right, million?
     MR. CULBERT: 150 as an estimate and 680 in savings.
     MR. KITCHEN: At the top of the range.
     MR. SHEPHERD: All right. Let me go to page 12 of
this presentation. This talks about your opportunity to
save money in customer care.
     If I understand, basically you have two utilities that
both have to do the same thing. They have to bill their
customers and talk to them on the phone, and all that
stuff, right, make sure that the customers are happy. And
there is a bunch of systems associated with that, and
there's a bunch of people associated with that, right?
     MR. CULBERT: That's correct.
     MR. SHEPHERD: And what you are saying is if you
integrate those two functions, the Union Gas function and
the Enbridge function, you're going to save some money.
You are going to save some money on the hardware and

software, and you are going to save some money on the people, right?

MR. CULBERT: That's the expectation, yes.

MR. SHEPHERD: And how does that relate to the amalgamation? How does the amalgamation require you -- how is the amalgamation necessary for you to do that integration? Tell me what the connection is between the two.

[Witness panel confers]

MR. PACKER: Mr. Shepherd, I think your question is why is amalgamation a necessity to integrate our CIS systems.

MR. SHEPHERD: Well, your customer care functions, yes.

MR. PACKER: So right now, both companies approach how they fulfill those responsibilities quite differently. You wouldn't -- I don't believe you would embark on a new CIS system without looking at integrating the way work is done, the processes, the structure and so forth. So those go hand in hand, and I don't think you would just do a system without those other changes which require the utilities to amalgamate.

MR. SHEPHERD: Why do they require the utilities to amalgamate? Enbridge Inc. right now standardizes a bunch of things around all its companies; it says you have to do those things the same way. Why couldn't it say Union Gas and Enbridge Gas Distribution, we want you to do customer care in the same way; in fact, we want you to do it in the same office? That's possible, right? There is no reason why you couldn't do that.

Mr. Kitchen and Mr. Culbert are making it difficult for me to see you -- probably intentionally.

MR. PACKER: You are putting a hypothetical to me that I guess is -- in some way might be theoretically possible, but I don't think it's practical.

MR. SHEPHERD: Well, let me ask Mr. Culbert because he's in the front row, and because he's with Enbridge, which is the reason.

Your -- there are a number of things at Enbridge, at Enbridge Gas Distribution, that are -- you do in a standardized way because Enbridge Inc. requires that they be done in a standardized way. Isn't that right?

MR. CULBERT: For example?

MR. SHEPHERD: I'm asking the question.

MR. CULBERT: I'm not sure what...

MR. SHEPHERD: You don't know of any?

MR. CULBERT: Sure, there are services that are taken from head office such as HR services went there, some IT services went there. Sure, they did.

But that's our relationship to Enbridge Inc. and the amalgamation of Union and Enbridge Gas Distribution is something that the board of directors has looked at as being an opportunity for us to integrate under the Board's policies, and that's the extent of our application.

MR. SHEPHERD: Sorry, what I'm trying to understand here, Mr. Culbert, is you have one gas distribution company in Ontario that has something like $35 million of its costs are actually from EI, right, under RCAM or something -- actually under CAM, it's probably 45 million. But under RCAM, it is 35 million or so, right?

MR. CULBERT: Yeah.

MR. SHEPHERD: A big chunk of your costs.

MR. CULBERT: We do have other panel members here that can --

MR. SHEPHERD: I'm asking you about Enbridge first, and then I'm going to come to Union and ask. Am I right that it's in the $35 million range?

MR. CULBERT: I don't know the exact number so -- it's somewhere in that ballpark.

MR. SHEPHERD: Okay. Is there any reason to believe that EI wouldn't simply require the same standardization from Union Gas? Why wouldn't they do that?

MR. CULBERT: Well, what I can comment about -- and there is another Enbridge person here who can possibly speak to it more than I can -- is that the services you are referring to are general IT services for work that's done in the office, the back office, et cetera. It is not charges for our customer care system.

The customer care system is specific at EGD, and I am going to assume it is the same, as you've pointed out, at Union. Those are specific platforms and software packages for customer care services.

We do not have any such thing being controlled or operated by EI. Those are specific to the utilities.

MR. CHARLESON: Perhaps, again when we're talking about customer care, it is a different function from when than when you talk about, say, corporate and kind of back office services.

When you look at customer care, the other thing -- as we operate today as two affiliated companies, we're both governed by the affiliated relationship code, ARC, and ARC has a lot of provisions around customer information, how it has to be segregated, how I has to be managed. So that would be a complicating factor in terms of how trying to operate under a common customer care framework as two independent entities.

MR. SHEPHERD: In the amalgamation scenario, what you are anticipating, I assume, and tell me whether this is right -- and I know you don't have detailed planning yet, but I'm just sort of the -- the movie in your mind is something like a single central customer care operation, which may be in Chatham or may be in Toronto, or may be diverse, but a single operation that shares a lot of services, a lot of people, and thus gains efficiencies. Is that fair?

MR. CHARLESON: Yes, that's fair.

MR. SHEPHERD: Why couldn't you do that without the amalgamation? I mean aside from the sharing of information thing, which I understand you'd have to get consent from the Board. But assuming that you got that, is there any barrier to doing that?

MR. REINISCH: Perhaps I could jump in and be helpful here. We can't look at a function like customer care in isolation of all the other functions and systems that we have, because something like our CIS system is so integrated with everything like our work management systems, our ERP systems.

For example, the functionality of the CIS system at Enbridge Gas Distribution is different than the functionality of the system at Union and how it ties to our asset management systems and our work management systems and the ERP systems, so you can't take a look at the one in isolation.

I agree that in the long-term what we are proposing is to harmonize all those things, and I wouldn't say a single geographic location -- you can do it the same virtually in a number of different locations as well, so we haven't even looked at those sort of things or gone into that detailed planning yet, but you really have to look at the whole in order to fully integrate the systems and processes between the two companies.

MR. SHEPHERD: But there is no barrier -- tell me whether this is correct. There is no barrier to you implementing your customer care integration without an amalgamation, right? As long as you operate the two utilities in concert you can still do the same things, right; the piece of paper that says you are amalgamated doesn't change that.

MR. CHARLESON: Jay, I would agree theoretically you are correct --

MR. SHEPHERD: Okay.

MR. CHARLESON: -- you could do that. However, I don't believe you would be able to achieve the benefits -- the degree of benefits and synergies that you get by amalgamating --

MR. SHEPHERD: Well, the -- and here's the interesting --

MR. KITCHEN: Sorry, sorry, Jay, and not only would you get the benefits, but it would be much more complex than operating as a single entity. We wouldn't have the affiliate code to deal with, we wouldn't have charges going back and forth that would need review by the regulator; it would be a much simpler and more efficient exercise to do an amalgamation.

MR. SHEPHERD: Sort of like KAM. Okay.

MR. KITCHEN: I'm not familiar with KAM, so --

MR. SHEPHERD: So -- believe me, you don't want to know.

What you are proposing is that after you amalgamate you are going to spend $65 million to integrate, and your payback over the first five years, if I calculate this correctly, is only 60 million.

It's in the second five years that you start to get the real serious benefits, another 25 million a year; am I understanding that right?

MR. CHARLESON: Yes, that is correct. There is a significant investment that needs to be made by the shareholder to allow for the amalgamation or the integration of those systems, and that's going to take a period of time, so you are making that investment, and there's limited benefits that you can achieve during that period while you are making that investment, so by the time you get the systems in place -- and again, the 65 million is an estimated number. That could be significantly higher. We may be able to do it for a bit less than that.

Benefits are uncertain. We still have to do the planning to really -- to drive that, but the -- but it's really until you have the systems in place, until you've made the investments, until the shareholder makes the investments to achieve that level of integration, that then creates the platform that you can start to derive greater benefits out of the integration, which will flow in the, kind of the second half of the deferred rebasing period.

MR. KITCHEN: Which is exactly why we need the ten-year time frame. The ten-year time frame, because we have a significant investment upfront, and until we make that investment we can't hammer out the processes that will achieve the savings.

MR. SHEPHERD: This is not the first time that Enbridge has faced this problem of a big front-end investment for great savings in customer care, is it?

MR. CULBERT: I'd say it's probably not the first time for Union Gas either, if I think about it.

MR. SHEPHERD: Well, except that Enbridge actually went through a process where it looked at the long-term costs and benefits of customer care and worked out a plan

ENBRIDGE GAS DISTRIBUTION INC. AND UNION GAS LIMITED

Undertaking of Mr. Culbert
To Mr. Shepherd

REF: Tr.2 p18

Please provide the achieved ROE and the allowed ROE for each of the last ten years for each of Union and Enbridge.

Response:

Please see the tables below. Please note that these tables were originally included in the response to OGVG Interrogatory #11 (Exhibit C.OGVG.11) and have been revised to included achieved ROE figures for 2008 to 2017.

EGD Earning Sharing Results

Year	Ratepayer Share of ESM ($Millions)	Gross Normalized Over Earnings (Above Allowed ROE + Threshold) ($Millions)	Achieved ROE % (1)	Allowed ROE %	Threshold / Deadband %	Ratepayer / Shareholder Sharing Ratio %	ESM / Deferral Clearance Proceeding
2008	5.60	11.20	10.21	8.66%	1.00%	50%/50%	EB-2009-0055
2009	19.30	38.60	11.20	8.31%	1.00%	50%/50%	EB-2010-0042
2010	17.35	34.70	11.10	8.37%	1.00%	50%/50%	EB-2011-0008
2011	14.30	28.60	10.38	7.94%	1.00%	50%/50%	EB-2012-0055
2012	7.39	14.80	9.28	7.52%	1.00%	50%/50%	EB-2013-0046
2013	-	31.20	10.41	8.93%	N/A	N/A	No ESM
2014	12.65	25.30	10.46	9.36%	0.00%	50%/50%	EB-2015-0122
2015	6.45	12.90	9.82	9.30%	0.00%	50%/50%	EB-2016-0142
2016	3.40	6.80	9.42	9.19%	0.00%	50%/50%	EB-2017-0102
2017	23.55	47.10	10.27	8.78%	0.00%	50%/50%	Preliminary results

Union Earning Sharing Results

Year	Ratepayer Share of ESM ($Millions)	Gross Over Earnings (Above Allowed ROE + Threshold) ($Millions)	Achieved ROE % (1)	Allowed ROE %	Threshold / Deadband %	Ratepayer / Shareholder Sharing Ratio %	ESM / Deferral Clearance Proceeding
2008	34.17	46.03	13.35%	8.81%	2.00%	90%/10%	EB-2009-0101
2009	7.40	14.79	11.24%	8.47%	2.00%	50%/50%	EB-2010-0039
2010	3.43	6.87	10.91%	8.54%	2.00%	50%/50%	EB-2011-0038
2011	2.54	5.08	10.38%	8.10%	2.00%	50%/50%	EB-2012-0087
2012	15.13	24.97	11.03%	7.67%	2.00%	90%/10%	EB-2013-0109
2013	-	32.20	10.67%	8.93%	N/A	N/A	No ESM
2014	7.42	14.85	10.69%	8.93%	1.00%	50%/50%	EB-2015-0010
2015	-	-	9.89%	8.93%	1.00%	N/A	EB-2016-0118
2016	-	-	9.24%	8.93%	1.00%	N/A	EB-2017-0091
2017	-	-	9.15%	8.93%	1.00%	N/A	Preliminary results

Notes:

(1) Union reports achieved ROE on an actual basis while EGD reports achieved ROE on a weather-normalized basis.

they still file debt separately, and we still have all the same reporting requirements and treasury requirements as two individual entities.

MR. SHEPHERD: Do you have the -- this is RCAM; right? The charge-out function is called RCAM?

MS. ZELOND: For EGD, correct.

MR. SHEPHERD: Okay, and so do you have the 2016 and 2018 breakdowns of RCAM and the equivalent for Union that you could provide us? Or could you include that in the undertaking?

MS. ZELOND: If you go to CCC 15, please?

MR. SHEPHERD: Yes.

MS. ZELOND: This response has RCAM for 2013 through 2017 for EGD.

MR. SHEPHERD: I understand that, so what I'm asking for is the equivalent for Union and 2018.

MS. ZELOND: So if we can go down two pages -- one more, thank you -- so Union Gas does not utilize the RCAM methodology, but rather affiliates and affiliate charges back and forth. This is the detail for Union that is closest representative to EGD.

MR. SHEPHERD: Okay. So do you have the 2018 for Enbridge?

MS. ZELOND: The 2018 amount for Enbridge in the response a few pages up is 50.2 million, and that the -- that the service allocation have not been finalized yet.

MR. SHEPHERD: Sorry --

MS. ZELOND: Sorry, it's in the answer. One more page.

MR. SHEPHERD: Oh, okay.

MS. ZELOND: Yeah, right there.

MR. SHEPHERD: But you don't have a breakdown for it?

MS. ZELOND: That is correct.

MR. SHEPHERD: How can you charge it if you don't have a breakdown? It's 2018 now. You are paying it now. I don't understand.

[Witness panel confers]

MS. ZELOND: This is the Board-approved methodology that EGD has been doing consistently through the years, so we have had no changes to that.

MR. SHEPHERD: The 50.2 is a placeholder, but you are paying it now. So I'm trying to understand what the breakdown is of that 50.2. You can't pay it unless you have an underlying support for it. That's the rule.

MS. ZELOND: As with our normal process, this is completed at the end of the year. We have not changed our process related to RCAM in 2018.

MR. SHEPHERD: All right. Fine, thanks.

MS. GIRVAN: Excuse me, I had a follow-up question just to something you said earlier. You said that currently with the finance function that Enbridge and Union have to file everything separately, but that's going to change January 1st, 2019; is that correct?

MS. ZELOND: That is correct. Under Amalco we will be a single entity and have one financial reporting, one annual report, and those documents. That is correct.

We've been through all of that.

So the companies did not have time to look at that type of detail in going forward with the presentation and recommendation to the board of directors. As Mr. Kitchen points out, we used what we had available in the limited time frame and we did an approach that you are seeing here.

MR. SHEPHERD: The reason I asked this is because you are estimating that ratepayers are going to save $411 million in rates over these ten years, and it looks like your -- whether or not your proposal -- your estimate of your actual proposal is a reasonable one, your estimate of the alternative, the custom IR, doesn't have any solid foundation. And I'm -- I am giving you an opportunity to say, no, here is the strong basis for it, but I hear you saying, no, there isn't. You really couldn't do that. It's too much work.

[Witness panel confers]

MR. REINISCH: So again, the costs that were assumed in the custom IR scenario, though they were not a bottom-up approach that would be taken under a custom IR filing, they were informed by significant amount of management experience. They were informed by the asset management plan and our required needs over the next ten years in order to ensure the growth of the system, as well as safe and reliable operations, and so the estimates that are contained in FRPO 11, though not as detailed as would be required under a custom IR filing, we do feel are appropriate and a prudent representation of the best available information we have available to us today.

MR. SHEPHERD: The asset management plan and the capital forecast is the same under both; right?

MR. REINISCH: That is correct. They underpin both.

MR. SHEPHERD: So the only difference is going to be in operating costs; right?

MR. REINISCH: There would be a difference in operating costs. There would also be a difference in costs that we would potentially be seeking recovery of.

MR. SHEPHERD: Because there might be costs that you have right now that you simply wouldn't ask to be recovered.

MR. REINISCH: There are costs right now that when the decision to defer rebasing was made, the decision to defer those costs until rebasing in 2029 was made.

MR. SHEPHERD: And I'm right, am I not, that you said that basically there was one meeting of senior leaders to talk about what these estimates should be; right? Isn't that what you said?

[Witness panel confers]

MR. REINISCH: So I believe the senior leader meeting that you're referring to is with respect to the synergies and the estimations that were included in the synergies.

With respect to development of the forecast, both the custom IR forecast as well as the proposed amalgamation forecast, those took place over a series of meetings involving a larger number of people within the planning, forecasting, and regulatory groups, as well as input from various other areas of the committee.

MR. SHEPHERD: So does that mean there is more backup to these numbers than what we've seen?

[Witness panel confers]

MR. REINISCH: I'm just going to point you to FRPO 11. That is the model that was used to develop these cost estimates, as well as revenue estimates, and the information and assumptions have been provided within that response.

MR. SHEPHERD: And that's it? That's all you got? There's no -- like, for example, embedded in those numbers are some OM&A numbers; right? And we've just talked about the fact that the difference between status quo and your current proposal has to be OM&A.

So is there some breakdown of OM&A somewhere that is embedded in these numbers?

MR. REINISCH: Not an additional level. There are assumptions on how we built up the OM&A in both instances, and those have been included in the response.

MR. SHEPHERD: All right. Sorry, that was a diversion. I want to go back to page 8 of FRPO 1, attachment 1. In this you took about the asset management plans, and right now as we sit here today you have two separate asset management plans, and whether you did a custom IR or you did -- you do your current proposal, it's the same asset management plan as right now?

[Witness panel confers]

MR. SKAARUP: No, the asset management plans are

ENBRIDGE GAS DISTRIBUTION INC. AND UNION GAS LIMITED

Undertaking of Mr. Culbert
To Ms. Girvan

REF: Tr.1, p.154

Please provide the 2018 forecast number of FTEs.

Response:

Please see the table below.

Year	Headcount	Reduction	Headcount Date	Estimated Annual Employee Savings	Gross Annual Severance Costs	Total Impact
2018	1938	-4	Feb month end	(521,924)	127,863	(394,061)
2017	1942	-129	Dec 31st	(16,832,049)	5,030,886	(11,801,163)
2016	2071	-67	Dec 31st	(8,742,227)	18,109,700	9,367,473
2015	2138	-66	Dec 31st	(8,611,746)	15,226,484	6,614,738
2014	2204	N/A	Dec 31st			

Notes:
Assumed average employee compensation = $130,481
Calculation assumes all headcount reductions were executed Jan 1 and had a full year equivalent.

MS. ZELOND: Okay, yes, so to address the jump in employees between '17 and '18, at the beginning of today I corrected the 2018 number for Union Gas.

MR. SHEPHERD: Oh, so that fixes that problem. That was a typo?

MS. ZELOND: Yes, we had included employees of a seasonal nature, interns, summer students. We had inadvertently included those employees in the 2018 number and did not include them in the numbers from 2012 to 2017. So the correct number is 2,252.

MR. SHEPHERD: So my question is: Why -- what forecast do you have going forward for FTEs? Any?

MS. ZELOND: No.

MR. SHEPHERD: Thank you. And then --

FOLLOW-UP QUESTIONS BY MR. LADANYI:

MR. LADANYI: Excuse me, can I ask a follow-up question on this?

On the first day I had asked questions about this particular interrogatory response and I had asked or I was trying to ask a question about who do we see represented in these numbers. Are these just permanent full-time employees or do they also include contract employees, part-time employees, as you said, seasonal employees? Could you tell us that?

MS. ZELOND: Yes. These figures include full-time and part-time regular employees as well as contractors. Now that 2018 number has been corrected it does not include seasonal employees, such as interns and summer students.

ENBRIDGE GAS DISTRIBUTION INC. AND UNION GAS LIMITED

Undertaking of Ms. Zelond
To Mr. Quinn

REF: Tr.3 p.11.

To provide detail supporting the change in transfer payments

Response:

The table below details the net costs/savings the utilities have received as a result of the Enbridge Inc. and Spectra merger. As indicated at Tr.3 p.11, the amounts are not considered material. Also on Tr.3, p.11, these costs and savings were characterized as transfer payments, and they are not.

JT 3.1 Union/EGD Corporate Cost Savings (in Millions)

	Union 2017			EGD 2017		
	Costs to Achieve	Savings	Net Total	Costs to Achieve	Savings	Net Total
Functional Area						
Finance/Regulatory	(0.2)	-	(0.2)	(0.9)	0.2	(0.7)
Facilities	(0.1)	-	(0.1)	-	0.6	0.6
HR	(1.0)	0.7	(0.3)	(0.6)	(0.6)	(1.2)
IT	(3.5)	1.5	(2.0)	(1.6)	1.2	(0.4)
Legal	(0.3)	-	(0.3)	-	0.1	0.1
SCM	(0.3)	0.3	-	-	(0.1)	(0.1)
Other	(0.7)	1.3	0.6	-	(0.1)	(0.1)
Total (Costs)/Savings	(6.1)	3.8	(2.3)	(3.1)	1.4	(1.7)

Notes
Costs to achieve include:
1. Unbudgeted expenses such as legal transaction costs and travel
2. Employee related costs such as severance, relocation and retention expenses
3. Included in the costs to achieve are severance costs of $4.7M for Union, and $3.1M for EGD
4. Credit in savings for EGD are a result of reorganizations, certain costs/savings regrouped between departments

Table 1 – Breakdown of ICM-eligible Projects [(1)] by Type

	ICM eligible projects (in $ millions)	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	Sum
1	Union Gas - Growth/Attachments	145	28	45	12	116	131	12	10	22	6	*527*
2	Union Gas - Maintenance	66	49	69	84	148	118	64	48	66	25	*737*
3	**Total Union Gas ICM Eligible Projects**	**211**	**77**	**114**	**96**	**264**	**249**	**76**	**58**	**88**	**31**	*1,264*
4												
5	Enbridge Gas Distribution - Growth/Attachments	-	-	-	-	-	-	-	-	-	-	-
6	Enbridge Gas Distribution - Maintenance	111	217	70	123	62	68	89	296	67	70	*1,173*
7	**Total Enbridge Gas Distribution ICM Eligible Projects**	**111**	**217**	**70**	**123**	**62**	**68**	**89**	**296**	**67**	**70**	*1,173*
8												
9	**Total ICM Eligible Growth/Attachments**	**145**	**28**	**45**	**12**	**116**	**131**	**12**	**10**	**22**	**6**	*527*
10	**Total ICM Eligible Maintenance**	**177**	**266**	**139**	**207**	**210**	**186**	**153**	**344**	**133**	**95**	*1,910*
11	*"ICM Eligible Projects" included in Exhibit C.FRPO.1 Attachment 1, slide 22, excluded from Rate Recovery [(2)]*	*1*	*14*	*2*	*5*	*6*	-	*6*	*18*	-	*51*	*103*
12	**Total**	**323**	**308**	**186**	**224**	**332**	**317**	**171**	**372**	**155**	**152**	*2,540*
13												
14	*Enbridge Gas Distribution - Maintenance, "ICM Eligible Projects" falling beneath ICM*											
15	*Threshold*	-	*14*	*39*	*33*	*13*	*89*	*96*	*132*	*141*	*138*	*695*

Notes:

(1) The ICM amounts in the Board presentation were based on the assumption that the identified amounts are eligible for ICM. The Asset Management Plans will be updated on an annual basis and the portfolio would be prioritized and optimized to the approved budget. Should there be risks and opportunities that exceed the materiality threshold, investments will be reviewed in relation to the approved ICM criteria.

(2) An amount of unidentified capital was included in the 10 year capital plan, but excluded from forecasted ICM rate recovery. These represent potential capital spend that may or may not qualify for ICM cost recovery (please see Transcript April 3, 2018, page 158 for discussion on these amounts).

Table 2 – Breakdown of Total Projects by Type

	Total Projects (in $ millions)	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	Sum
1	Total ICM-eligible Growth/Attachments Projects (from Table 1, row 9)	145	28	45	12	116	131	12	10	22	6	*527*
2	Total ICM-eligible Maintenance Projects (from Table 1, row 10)	177	266	139	207	210	186	153	344	133	95	*1,910*
3	Total Attachments Projects	336	289	271	323	353	270	287	274	268	286	*2,957*
4	Total Maintenance Projects	561	556	568	526	501	587	578	597	607	598	*5,679*
5	Other (from Table 1, row 11)	1	14	2	5	6	-	6	18	-	51	*103*
6	**Total**	**1,220**	**1,153**	**1,025**	**1,073**	**1,186**	**1,174**	**1,036**	**1,243**	**1,030**	**1,036**	***11,176***

ENBRIDGE GAS DISTRIBUTION INC. AND UNION GAS LIMITED

Undertaking of Mr. Reinisch
To Mr. Brett

REF: Tr.3 p.189.

To update the figures in FRPO 11, Table 15 to show year by year data.

Response:

Please see the table below as requested.

ICM THRESHOLD CALCULATION

		2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
ICM THRESHOLD CALCULATION FORMULA											
ICM Threshold Value = 1 +[(rb/d) * (g + PCI * (1 + g))] * ((1 + g) * (1 + PCI))^n-1 + 10%											
Threshold Factor	10%										
Base year	**2013**										
Ratebase	3,734										
Rebasing Depreciation Expense	196										
Growth rate		0.99%	0.99%	0.99%	0.98%	0.98%	0.97%	0.97%	0.97%	0.97%	0.97%
PCI		1.73%	1.73%	1.73%	1.73%	1.73%	1.73%	1.73%	1.73%	1.73%	1.73%
N - Number of years since rebasing		6	7	8	9	10	11	12	13	14	15
ICM multiplier		*1.70*	*1.71*	*1.73*	*1.74*	*1.76*	*1.78*	*1.80*	*1.81*	*1.83*	*1.85*
ICM Threshold value		**$ 333**	**$ 336**	**$ 339**	**$ 342**	**$ 345**	**$ 349**	**$ 352**	**$ 356**	**$ 359**	**$ 363**

ENBRIDGE GAS DISTRIBUTION INC. AND UNION GAS LIMITED

Answer to Interrogatory from
London Property Management ("LPMA")

Rate Setting Issues List – Issue No.1

Reference: Exhibit B, Tab 1, pages 12-16

Question:
For each of Union and EGD, please calculate the threshold percentage and value for each of 2014 through 2018 and then compare the threshold value to the actual capital expenditures in those years. For 2018, please use the forecasted level of capital expenditures.

Response

For 2014 to 2018, EGD set rates under a custom IR framework which does not permit any ICM. In order to perform such a calculation for EGD, various assumptions would have to be made regarding the inflation factor and the X factor implicit in a Price Cap formula, which are not resident within EGD's Custom IR.

For Union, capital pass through was subject to the capital pass through mechanism agreed to in the EB-2013-0202 Settlement Agreement. Actual capital expenditures relative to the ICM threshold is not relevant to 2014-2018, however the data is provided in the table below for information.

Illustrative 2013-2018 Union ICM Materiality Threshold

	$ Millions	**2013**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**
		Board	Actuals					Forecast
(1)	Growth and Maintenance CapEx	268	316	322	339	343	353	443
(2)	Capital Pass Through Projects	80	52	155	352	691	368	115
(3)	Total Capital Expenditures	348	368	477	691	1,034	721	558
	ICM (Illustrative)							
(4)	ICM Materiality Threshold*	268	268	271	278	280	281	281
(5)	Total Capital Expenditures		368	477	691	1,034	721	558
(6)	**CapEx in excess of Threshold**		**100**	**206**	**413**	**754**	**440**	**277**
(7)	CapEx recovered through CPT		52	155	352	691	368	115
(8)	CapEx invested above Threshold and CPT		***48***	***51***	***61***	***63***	***72***	***162***

* *ICM Materiality Threshold calculated as per Report of the OEB: EBO-2014-0219 New Policy Options for Funding for Capital Investments: Supplemental Report, January 22, 2016*

400 million, and a ROE of 8.97 percent. So we calculate that that means your rate base was 12.4 million forecast for 2018.

It's just 400 divided by .087, divided by .36, which is correct, right? That's how do you it?

MR. REINISCH: The math is correct.

MR. SHEPHERD: Okay. So I don't understand why your forecast for your board was 12.4 million and you have a current forecast of 12.856 million. Did something change or are these done on a different basis?

I'm happy if you wanted to undertake to deal with that, just reconcile the two numbers.

[Witness panel confers]

MR. REINISCH: We'll undertake to provide a reconciliation of the difference.

MR. MILLAR: JT3.17.

UNDERTAKING NO. JT3.17: TO RECONCILE RATE BASE FIGURES GIVEN IN APPLICANT BOARD MATERIAL VERSUS CURRENT FORECAST

MS. GIRVAN: Sorry, Mr. Shepherd, can you explain this table?

MR. SHEPHERD: I'm going to get to that.

MS. GIRVAN: Okay.

MR. SHEPHERD: So still on BOMA 29, this tells me that Union increased its rate base from 2012 to 2018 -- this is six years, by 64.1 percent. Will you accept that subject to check?

MR. REINISCH: I can accept subject to check.

MR. SHEPHERD: And Enbridge increased its rate base from 4 billion to 6.7 billion, which is a 67.1 percent increase.

In total, the compound annual growth rate in rate base is 8.7 percent; will you accept that subject to check?

MR. REINISCH: I can.

MR. SHEPHERD: And so I'm -- some portion of this -- or let me start with Union. Some portion of that was tracked by your capital tracker in your last rate plan; right?

MR. REINISCH: So there are two main drivers for rate base growth within Union Gas, as well as within Enbridge Gas Distribution, over the period in question.

With respect to Union Gas, the first driver is our annual customer additions, so each year we've been adding approximately 20,000 customers. Those customers require capital in order to attach meters, distribution mains, along the premises, as well as, as you pointed out, there has been a significant amount of capital growth driven by a number of large projects that have qualified for the capital pass-through mechanism.

MR. SHEPHERD: And that's about $1.5 billion over the last -- that came through the capital tracker mechanism, right? I'm looking at LPMA 23. It is actually closer to 1.7 billion. Do you see that, line 7?

MR. REINISCH: It is approximately 1.6-, 1.7 billion, correct.

MR. SHEPHERD: Now, the other interesting thing in

MR. SHEPHERD: Okay. Help me understand that.

MR. REINISCH: You don't have to pull this up, but as indicated in response to Board Staff 5, Union Gas is planning -- or, I'm sorry, Amalco is planning on bringing forward in the 2019 rates application proposals to recover ICM-eligible costs for both the Panhandle and Sudbury projects.

The Sudbury project is a project to replace end-of-life assets into the Sudbury market off of the TransCanada Pipeline that need to be done in 2018, by November 1st of this year, of 2018.

So the project itself is one that I will say falls between the two periods, the capital pass-through period, as well as the ICM period, so as part of the rates application Amalco will be proposing a cost recovery of the investment.

MR. SHEPHERD: That's 96 million?

MR. REINISCH: No.

MR. SHEPHERD: No. What is it then?

[Witness panel confers]

MR. REINISCH: It is approximately 74 million.

MR. SHEPHERD: And so it wouldn't qualify for ICM, because you don't qualify for ICM in 2018; right?

MR. KITCHEN: Sorry, if you could just repeat your question, Jay, for me.

MR. SHEPHERD: It wouldn't qualify for ICM because you don't qualify for ICM in 2018; right?

MR. KITCHEN: I guess I would look at it slightly differently. I would say that it would have qualified as a major capital project under our old threshold, and it would qualify if we were under an ICM for 2018, which is why when Mr. Reinisch spoke about something falling between the cracks, this is one of those -- this is what we mean by that falling between the cracks. It would qualify, and therefore bring it forward for approval.

MR. SHEPHERD: Sorry, why are you not bringing it forward for capital pass-through as opposed to ICM? Is the amount that qualifies different?

MR. KITCHEN: No, the amount that qualifies wouldn't be different, but --

MR. SHEPHERD: Is the treatment different in some way?

MR. KITCHEN: The treatment would not be different. We would still get to pass those costs through. We felt that it was better to do it under the ICM.

MS. GIRVAN: Okay. Why didn't you include it in your 2018 rate proposal?

MR. KITCHEN: Because it is not in-service until November of 2018, the full-year cost coming in '19.

MR. SHEPHERD: All right, so this 323 million that you are currently forecasting for 2019 in new ICM capital, that doesn't include that 74 million?

MR. REINISCH: No, it does include that amount.

MR. SHEPHERD: It does include that. Okay, so then the opening -- okay, so you're saying technically there is an opening rate base but, in fact, because you are pretending it is 2019 for regulatory purposes, it is approved, and then we will be able to come back with a (inaudible). So it is a range. It could be as little as two years or it could be as long as, you know, four, five, or six years per se.

MS. GIRVAN: Okay. Thank you.

And just -- you don't really have to pull this up, but we were looking earlier at the original evidence, and it was table 3 which set out the two scenarios, the stand-alone scenario versus the Amalco's scenario.

And what did you assume for DSM for both the stand-alone and the Amalco scenarios? Was it the same thing?

MR. REINISCH: Yes, the same DSM assumptions were under both.

MS. GIRVAN: So what did you assume beyond when the current plans expire?

MR. REINISCH: Those assumptions are contained in FRPO 11.

MS. GIRVAN: Okay.

MR. REINISCH: For Enbridge Gas Distribution they can be found in table 1 and for Union Gas in table 5. 2.3 for Enbridge Gas Distribution and 2.2 for Union Gas.

MS. GIRVAN: Okay. So you've just -- it seems that you've just inflated them; is that right, under both scenarios?

I guess what I'm looking for is, is there a difference between what you've assumed with respect to DSM under the stand-alone scenarios versus the Amalco scenario?

MR. REINISCH: No, the underlying assumption on DSM of your increase in revenues over ten years?

MR. CULBERT: Is that on your spreadsheet, Jay?

MR. SHEPHERD: It is, the upper right corner.

MR. CULBERT: That is the total DX revenue growth?

MR. SHEPHERD: Yes. If you don't know the number, we can get to it later. I'm okay with that. I thought you would know this.

MR. REINISCH: Yes. Revenue again is forecasted to grow by approximately 38 percent over the ten-year period.

MR. SHEPHERD: Awesome. Thank you. The other thing that's on here is the second last bullet on the left-hand side. I'm still on page 7, and it says you have an opportunity to integrate demand-side management and continue cost effective delivery of Ontario government low carbon programs.

Your current application doesn't do that, right? It doesn't propose that?

MR. CULBERT: That's correct.

MR. SHEPHERD: And so that changed from the time you presented this to the board of directors to now, or was that always intended to be deferred?

MR. KITCHEN: I don't think that's -- that's not a change at all, because what the bullet says is there is an opportunity and once we get approval to amalgamate from this the OEB and our board, we will go we will enter into detailed planning and that will include how we will address bringing DSM together. But it's the -- opportunity is the key word.

MR. SHEPHERD: So right now, the Board doesn't know how you are going to do that? Our Board, not your board.

MR. KITCHEN: No, they do not, and we have not looked at it.

MR. CULBERT: We don't know how we are going to do that.

MR. SHEPHERD: Is there anything you can say that would help the Ontario Energy Board understand how these are like -- these two programs are likely to be integrated?

MR. KITCHEN: I don't think that that's actually necessary right now. We haven't got approval to amalgamate and/or of the rate-setting mechanism. Until we have those things, there is not going to be any detailed planning done around any part of the integration and at the time we bring -- we will bring forward at some point through the DSM process how we plan to amalgamate them.

MR. SHEPHERD: I understand that. I was giving you an opportunity to give a general statement about this to help the Board understand this particular issue. Obviously, it's going to come up. And so you don't want to say anything about it, that's fine.

MR. CULBERT: Well, I think, Jay, we can't say anything about it, to Mark's point. We don't know at this point in time.

MR. SHEPHERD: That's fine. I'm on page 9 now, and page 9 says that over ten years, the utility will earn $111 million more than under the MAADs approach than it would, I guess, under custom IR. Is that right?

MR. PACKER: Sorry, what is your reference? I believe that's the reference --

MR. SHEPHERD: On page 13 is -- and this is about how you are going to integrate your work management systems; right?

MR. PACKER: What we are talking about here is the back-shop systems that are used to schedule work in the field.

MR. SHEPHERD: And in fact your estimates, both your OM&A, and you have -- your capital estimate is zero, but your estimates of integration savings, 680 million, that includes zero for field operations; right? There is no amount in that 680 million for field operations right now.

MR. CHARLESON: That's correct.

MR. SHEPHERD: And field operations is, in fact, the biggest expense you have, isn't it?

MR. RIETDYK: So typically -- so this includes generally the systems, the back-shop processes. I think in the future we do contemplate the potential for some potential savings for field operations, but that's not the focus, certainly, in the first five years of the amalgamation.

MR. SHEPHERD: I guess what I'm frying to drive at is, and maybe slowly, is you have a number of your service territories that are contiguous, and as a single entity you will be able to serve them as one; right?

MR. RIETDYK: That's correct.

MR. SHEPHERD: So let me give you an example.

But I would have to believe that Enbridge Inc. had to do some prior analysis prior to its acquisition of Spectra, which likely included not only what could happen between Spectra and Enbridge and all the other functions they do, but in respect of the two utilities they would now own and synergies that could be created.

So you've told us there is no document to show you the -- that supports the analysis behind the range of savings and costs that we see in those summary slides in FRPO 1. But there must be an Enbridge document, an Enbridge Inc. document that analyzed this merger and the potential synergies.

Would you undertake to provide that document?

MR. KITCHEN: No, utilities were not included in any analysis around the merger.

MR. SHEPHERD: How do you know that?

MR. KITCHEN: I was told that.

MR. SHEPHERD: So Enbridge acquired Spectra and deliberately didn't analyze whether there was going to be any benefit to merging the regulated utilities; is that what you're saying?

MR. KITCHEN: That's what I'm saying. They came together and they looked at savings of -- between Spectra and Enbridge Inc., they did not go down to the utilities.

MR. SHEPHERD: Thank you.

MR. QUINN: Okay, moving on. I think because we're in BOMA, if we just stick with BOMA 19 because it pertains to the integration of the distribution work management system.

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

c) Please see Table 1 below.

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

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

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

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

DECISION ALLOWED REVENUE
AND SUFFICIENCY / (DEFICIENCY)
2014 - 2018 FISCAL YEARS

Line No.		Col. 1 2014 EGD Total	Col. 2 2015 EGD Total	Col. 3 2016 EGD Total	Col. 4 2017 EGD Total	Col. 5 2018 EGD Total
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)
	Cost of Capital					
1.	Rate base	4,421.4	4,847.0	5,696.0	5,948.6	6,152.6
2.	Required rate of return	6.79%	6.89%	7.00%	7.04%	7.12%
3.		300.0	333.8	398.6	418.7	438.1
	Cost of Service					
4.	Gas costs	1,456.3	1,606.8	1,632.5	1,632.5	1,632.5
5.	Operation and maintenance	425.3	427.3	431.1	436.9	442.8
6.	Depreciation and amortization	248.5	261.7	288.9	297.7	305.5
7.	Fixed financing costs	1.9	1.9	1.9	1.9	1.9
8.	Municipal and other taxes	41.2	43.1	45.5	47.9	50.4
9.		2,173.2	2,340.8	2,399.9	2,416.9	2,433.1
	Miscellaneous operating and non operating revenue					
10.	Other operating revenue	(42.7)	(42.7)	(42.7)	(42.7)	(42.7)
11.	Other income	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)
12.		(42.8)	(42.8)	(42.8)	(42.8)	(42.8)
	Income taxes on earnings					
13.	Excluding tax shield	65.9	48.9	47.1	54.8	68.3
14.	Tax shield provided by interest expense	(39.5)	(42.8)	(49.6)	(52.0)	(54.6)
15.		26.4	6.1	(2.5)	2.8	13.7
	Taxes on sufficiency / (deficiency)					
16.	Gross sufficiency / (deficiency) - with CIS/CC	66.0	10.2	(77.9)	(117.9)	(163.6)
17.	Net sufficiency / (deficiency) - with CIS/CC	48.5	7.5	(57.3)	(86.7)	(120.3)
18.		(17.5)	(2.7)	20.6	31.3	43.4
19.	Sub-total Allowed Revenue	2,439.3	2,635.2	2,773.8	2,826.9	2,885.5
20.	Customer Care Rate Smoothing Var. Adj.	(2.9)	(1.1)	0.8	2.9	5.0
21.	**Allowed Revenue**	2,436.4	2,634.1	2,774.6	2,829.8	2,890.5
	Revenue at existing Rates					
22.	Gas sales	2,254.0	2,404.3	2,464.5	2,480.3	2,496.2
23.	Transportation service	242.8	229.6	217.1	211.1	205.0
24.	Transmission, compression and storage	1.8	1.8	1.8	1.8	1.8
25.	Rounding adjustment	(0.1)	0.1	-	0.3	0.3
26.	Total	2,498.5	2,635.8	2,683.4	2,693.5	2,703.3
27.	**Gross revenue sufficiency / (deficiency)**	62.1	1.7	(91.2)	(136.3)	(187.2)
	Impact on Rates from Decision					
28.	Year over Year change in Rates from Decision (Current Year Sufficiency/Deficiency minus previous year Sufficiency/Deficiency)	62.1	(60.4)	(92.9)	(45.0)	(50.9)
	COMPARISON TO 2013-11-22 Updated Filing					
29.	**Gross revenue sufficiency / (deficiency) from Updated Filing**	31.2	(29.1)	(119.7)	(166.1)	(215.7)
30.	Year over Year change in Rates from Updated Filing (Current Year Sufficiency/Deficiency minus previous year Sufficiency/Deficiency)	31.2	(60.3)	(90.6)	(46.4)	(49.6)
31.	**Gross revenue sufficiency / (deficiency) change from Updated Filing to Decision** (line 27 minus line 29)	30.9	30.8	28.5	29.8	28.5

MR. SHEPHERD: Then storage and transmission lines is panel 3, is that right?

MR. MANDYAM: Yes.

MR. SHEPHERD: Then I have just -- sorry, I have to find something. I have a question on LPMA 8, attachment 2. It is the Union Gas 2017 annual report.

Are you the right people to ask that question?

MR. KITCHEN: Sorry, Jay?

MR. SHEPHERD: I said you are the right people to ask about this?

MR. KITCHEN: Well, if you put it to us and we can't, we'll figure out who can.

MR. SHEPHERD: This is on page 6 of the annual report. I've never seen this in any of the Union Gas stuff beforehand, so I'm -- that's why I'm asking. It says there is no audit committee of the board. Do you see that at the top of page 6?

And the reason I ask is because the board of directors of Union Gas is -- tell me whether this is true -- one-third Enbridge Inc. management, one-third Union management, and one-third independent; is that right?

MR. KITCHEN: That's correct.

MR. SHEPHERD: So I'm not sure why you don't have an audit committee. That means management controls their audited statements? I didn't think that was legal, let alone appropriate.

[Witness panel confers]

MR. KITCHEN: Sorry, Jay, I'm just looking for an IR that we answered on governance. And I just don't recall the number.

There we go. So if you look at FRPO 10, on page 3, about halfway down it says:

"Enbridge Inc. employs a governance model whereby certain governance functions that are common across the Enbridge Inc. organizations are overseen at the parent company level. The utilities enjoy, as Amalco will, significant benefits by having committees such as audit, finance, and risk committee, human resources, and compensation committee, the corporate social responsibility committee, and the safety and reliability committee operating at the parent level."

MR. SHEPHERD: So -- I see. That's good. So this is one of the ways in which you've already made the company more efficient by changing the governance at Union Gas so that some stuff is bumped up to EI; right?

MR. KITCHEN: The structure under Spectra was similar, that it was done at a corporate level as well.

MR. SHEPHERD: But now it's all done in one place?

MR. KITCHEN: With the merger of Spectra and EI there is a single -- there are single audit committees and/or the other committees that I just spoke about.

MR. SHEPHERD: All right. I think -- oh, I know, hang on. No. Okay, I think that's all I have right now. Thank you.

April 27, 2018

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

Dear Ms. Walli:

Re: Draft Report of the Board on Corporate Governance Guidance for OEB Rate-Regulated Utilities dated March 28, 2018 ("Report")

Enbridge Gas Distribution Inc. and Union Gas Limited (the "Companies") have reviewed the Draft Report of the Board on Corporate Governance Guidance for OEB Rate-Regulated Utilities dated March 28, 2018 ("Report"). The Companies and their mutual parent affiliate, Enbridge Inc. ("Enbridge"), appreciate the opportunity to provide the OEB with written comments on the guidance on best practices for utility governance and on the new mandatory reporting and record keeping requirements. As the OEB is aware, the Companies applied to the Board in late 2017 under docket number EB-2017-0306 to amalgamate effective January 1, 2019. The Companies have therefore chosen to make joint submissions on the Report.

Strong governance of OEB regulated utilities is a laudable goal. Enbridge and the Companies not only believe in the value of good governance, but have invested heavily for decades in establishing quality governance practices suited to a business of our scope and size.

Our approach focuses on substantive governance and encompasses a holistic view of governance and our stakeholders. We include safety, financial responsibility and performance, ethics, compliance, corporate social responsibility and sustainability in our definition of governance. As we say in Enbridge's most recently filed Statement on Corporate Governance, sound governance means sound business.

While we support the goal of strengthening governance, there are some key elements of the Report that must be addressed. Broadly speaking, the Report does not currently reflect the right balance of substance over form, which is necessary and reasonable to accommodate the diverse characteristics and structures of the utilities regulated by the OEB.

Where regulated utilities are part of a publicly held company structure, the OEB should recognize and accept the operating, legal and governance structures that already apply, instead of imposing distinct but overlapping regulation to promote governance. Other regulated utilities in different circumstances will not be subject to the established and robust governance requirements that apply to public companies and in those cases it may be justifiable for the OEB to prescribe expectations and reporting formats. We also urge the OEB to reconsider the notion, contemplated in the Report, of amending the *Affiliate Relationships Code for Gas Utilities* ("ARC") to prescribe a majority of independent director appointments.

Operating, Legal and Governance Structures of Public Companies Must be Recognized

The Companies agree with the OEB's approach to offer guidance rather than prescriptive measures on corporate governance. However, we are concerned with the strong implication of a "one size fits all" approach in the Guidance on Best Practices for Utility Governance section of the Report. The OEB should acknowledge that different models may be appropriate and effective in achieving the goal of good governance and strong reporting, depending upon the corporate structure.

In our case, the Companies are wholly-owned operating subsidiaries of a parent entity, Enbridge, that is a widely-held public company listed on both the TSX and the NYSE. The Companies themselves are also issuers of publicly held debt instruments. All of these features already bring with them a myriad of mandatory and voluntary best practices in governance structures and reporting including requirements for independent directors of Enbridge. They also influence our view that governance for the Companies is best achieved in an integrated way instead of on a stand-alone basis for each entity.

We recommend that the final Report recognize integrated corporate governance models such as ours as being appropriate for rate regulated utilities in Ontario. Ours is a model whereby certain governance functions that are common across our organization are overseen by the board of directors of Enbridge. The Companies enjoy significant benefits with respect to the governance of the Ontario utilities by having high-caliber, robust committees of the board operating at the parent level.

For example, the Companies are able to leverage: (a) the broad representation of independent board members at the parent level (11 of the 13 board members of Enbridge are independent); (b) the identification and implementation of governance best practices for an energy infrastructure business (which includes a rate regulated utility business); and (c) the benefits from the efficiencies of having a consistent application of corporate policies, standards and enterprise systems like our compliance program and Statement of Business Conduct, information technology standards and security and strong internal controls (COSO and SOX) environment. In sum, Enbridge has a comprehensive governance system that follows best practices and fully meets, and in many cases exceeds, the requirements of applicable laws, rules, regulations and standards.

Operating subsidiaries in such a corporate family should be encouraged to leverage these existing investments, which entail substantial cost and considerable effort. Requiring all of the governance functions to be replicated and carried out independently at the subsidiary level will result in unjustifiable duplication of effort, inefficiencies, loss of significant benefits and unnecessary additional costs at the Companies with no corresponding benefit.

Reporting of Public Companies Must be Recognized

The Companies agree with the OEB that mandatory reporting is an effective promoter and reinforcement of good governance. We believe, however, that businesses that are already subject to extensive mandatory and voluntary reporting structures should be entitled to rely on public reports to meet their reporting obligations under the OEB's mandatory reporting regime. We urge the OEB to make this an express exception to its final reporting requirements for companies subject to an existing governance reporting regime.

The Companies do not support the creation or filing of any additional disclosure documents on corporate governance. Canadian securities legislation already addresses corporate governance disclosure for public issuers, which is readily accessible to all of the operating subsidiary's stakeholders including the OEB. Enbridge on its own behalf and on behalf of the Companies also provides extensive voluntary public disclosure on governance-related topics in documents such as its CSR & Sustainability Report, available and updated on its website.

Creating similar but distinct mandatory reports for the OEB to cover overlapping subject matter would not add value, but would lead to duplication of effort and additional and unnecessary costs. Additional off-cycle public filings related to governance matters already addressed in securities filings also pose an audit risk to reporting issuers such as the Companies that public filings may be viewed as inconsistent depending upon timing of disclosure and may inadvertently require additional securities filings.

Finally, we do not support the requirement to map committee mandates to the key board functions identified by the OEB. Here, the OEB is imposing its views on what sorts of functions should be undertaken by a board of directors and how such functions should be undertaken. This is counter to the *Ontario Business Corporations Act* and common law jurisprudence which gives broad discretion to the board of directors to manage a corporation in the best interests of the corporation.

Neither Canadian securities laws nor corporate laws prescribe the key functions of a board or require a mapping of such functions to committee mandates. We satisfy our mandatory and voluntary explanation requirements through detailed descriptions of the board's function and role. Given our earlier comments about our approach to governance, a detailed mapping is not appropriate for corporations that own and oversee operations beyond the regulated utility business, over which the OEB does not have jurisdiction.

The OEB already has extensive control over certain business practices of rate-regulated entities through its powers to approve rates, to issue licenses and to make codes. We do not think it is necessary or appropriate to extend the OEB's jurisdiction to effectively direct the key functions of a board of directors of a utility. We recommend the OEB remove from the report its guidance on the key functions of a utility board and the requirement to map such functions to committee mandates.

Independence

Enbridge knows the value of independent and diverse thinking to good governance. We have long benefited from independent representation on Enbridge's board and again on the Companies' boards. However, a universal majority independence requirement for every OEB regulated utility is a step too far, with questionable benefit. The current ARC requirement that one-third of the utility board of directors be independent from any affiliate is consistent with corporate law principles and achieves an appropriate balancing of interests for wholly-owned subsidiaries of widely-held public corporations such as the Companies. The OEB ought not to be applying an independence definition or requirement different from or inconsistent with existing corporate law principles.

Unlike a municipally owned utility, corporate law applies from the Companies' own structure through to the top parent-level ownership of the utility business at Enbridge. Under corporate law, directors of a given corporation both have legal fiduciary duties to the corporation and have been given substantial deference by courts to manage or supervise the affairs of the corporation, in its best interests. These interests are now understood to extend well beyond simple economic interests of its shareholders; indeed, the directors cannot simply exercise their discretion when voting as a board member to effect the will of the shareholder that appointed them. The board of the Companies, and the board of the Companies' shareholders in appointing those boards, must have their discretion in these regards respected.

Yes, the best interests of the corporation are necessarily subject to the rules and objectives of regulation in the case of a utility. However, this does not require the regulator to impose its own decision on the governance design of an operating subsidiary utility, in place of that of its owner. This tool is neither core to the OEB's mandate nor required to achieve a benefit that could not accrue without it.

Moreover, establishing mandatory levels of board size and independence for utilities such as the Companies will have a direct impact on the cost and efficiency of governance at both the utility and parent levels. Each new director, meeting, committee and administrative support system comes at a cost and resource commitment. Where there is little benefit or harm demonstrated, this cost just can't be justified. The Companies operate in an environment where productivity and efficient allocation of resources is promoted. They need the latitude to accomplish good governance in alignment with these other goals.

Conclusion

Unlike municipally or privately owned utilities, Enbridge and the Companies have been subject for many years to extensive regulation and market expectations for governance. Our governance structures and reporting have grown and evolved within these frameworks. The OEB should not layer on incremental interpretations and requirements that come with real cost and illusory benefit.

Instead, the OEB should recognize these factors and seek to regulate where governance-oriented public company regulation does not already apply. Its guidance and rules should be flexible enough to accept structures and reporting that have been adapted to meet the end goal of good governance under other rules like those already applicable to the Companies, while promoting that end goal as a principle and as a regulatory activity where the public company framework does not apply.

Yours truly,

Andrew Mandyam
Director, Regulatory Affairs
Enbridge Gas Distribution

Mark Kitchen
Director, Regulatory Affairs
Union Gas Limited

Ten Year Revenue and Expense Forecast - Enbridge and Union ($M)

		2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	Increase
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
1	***Dx Revenue - Enbridge***	$1,257	$1,305	$1,353	$1,398	$1,440	$1,482	$1,523	$1,565	$1,619	$1,671	$1,715	36.45%
2	***- Union***	$1,157	$1,225	$1,277	$1,311	$1,348	$1,390	$1,441	$1,489	$1,525	$1,563	$1,599	38.20%
3	***Total Dx Revenue***	$2,414	$2,530	$2,630	$2,709	$2,788	$2,872	$2,964	$3,054	$3,144	$3,234	$3,314	37.29%
4	***Increase***		4.80%	3.97%	2.98%	2.93%	3.03%	3.18%	3.05%	2.93%	2.88%	2.46%	
5	***Cumulative***		$2,530	$5,160	$7,868	$10,656	$13,529	$16,492	$19,546	$22,690	$25,925	$29,239	
6	***Status Quo Revenue***	$2,414	$2,531	$2,657	$2,767	$2,850	$2,932	$3,014	$3,103	$3,174	$3,268	$3,351	38.82%
7	***Increase***			4.98%	4.14%	3.00%	2.88%	2.80%	2.95%	2.29%	2.96%	2.54%	
8	***Cumulative***		$2,531	$5,188	$7,955	$10,805	$13,737	$16,751	$19,854	$23,028	$26,296	$29,647	
9	***O&M - Enbridge***	$370	$375	$383	$392	$399	$406	$413	$420	$427	$434	$442	17.87%
10	***- Union***	$371	$380	$393	$400	$410	$421	$431	$442	$453	$464	$475	25.00%
11	***O&M w/o Synergies***	$741	$755	$776	$792	$809	$827	$844	$862	$880	$898	$917	21.46%
12	***Increase***		1.89%	2.78%	2.06%	2.15%	2.22%	2.06%	2.13%	2.09%	2.05%	2.12%	
13	***Synergies***		$3	$38	$63	$70	$81	$85	$85	$85	$85	$85	
14	***O&M w/ Synergies***	$741	$752	$738	$729	$739	$746	$759	$777	$795	$813	$832	10.64%
15	***Increase***		1.48%	-1.86%	-1.22%	1.37%	0.95%	1.74%	2.37%	2.32%	2.26%	2.34%	
16	***Total ROE***	$400	$445	$483	$500	$512	$526	$547	$562	$591	$603	$609	52.17%
17	***Percentage***	8.97%	9.20%	9.50%	9.40%	9.40%	9.40%	9.50%	9.50%	9.70%	9.70%	9.60%	
18	***Implied Rate Base ($B)***	$12.4	$13.4	$14.1	$14.8	$15.1	$15.5	$16.0	$16.4	$16.9	$17.3	$17.6	42.12%
19	***Increase***		8.36%	5.11%	4.62%	2.40%	2.73%	2.90%	2.74%	2.99%	2.03%	2.05%	
20	***Customers (000s)***	3600	3650	3700	3750	3800	3850	3890	3930	3970	4010	4050	12.50%
21	***Revenue/Customer***	$670.53	$693.07	$710.84	$722.27	$733.65	$746.05	$761.88	$777.16	$791.88	$806.57	$818.27	22.03%
22	***Increase***		3.36%	2.56%	1.61%	1.58%	1.69%	2.12%	2.00%	1.89%	1.86%	1.45%	
23	***OM&A/Customer***	$205.83	$206.03	$199.46	$194.40	$194.47	$193.77	$195.12	$197.71	$200.25	$202.74	$205.43	-0.29%
24	***Increase***		0.09%	-3.19%	-2.54%	0.04%	-0.36%	0.70%	1.33%	1.29%	1.24%	1.33%	
25	***Rate Base/Customer***	$3,444	$3,681	$3,817	$3,940	$3,982	$4,037	$4,112	$4,181	$4,263	$4,306	$4,351	26.33%
26	***Increase***		6.88%	3.69%	3.23%	1.05%	1.40%	1.84%	1.70%	1.95%	1.01%	1.04%	

Sources: Forecasts from C.FRPO.1, Attachment 1, pages 9, 21 and 23
2018 from C.SEC.16, C.SEC.18 and C.SEC 19

Impacts of ICM Proposal for Customers

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	Totals
Opening Rate Base	0	315	593	753	943	1,233	1,504	1,616	1,910	1,998	
New ICM Capital	323	294	184	219	326	317	165	354	155	101	2,438
Depreciation	8	17	23	29	36	46	53	60	67	71	
Closing Rate Base	315	593	753	943	1,233	1,504	1,616	1,910	1,998	2,028	
Depreciation	8	17	23	29	36	46	53	60	67	71	410
Cost of Capital	13	35	49	60	73	92	107	120	132	136	816
Tax	-2	-2	-2	-1	-3	-4	-3	0	2	5	-10
Total ICM Revenue	18	49	70	87	107	133	157	180	201	212	1,215
Threshold Capital	832	838	839	848	854	859	865	871	878	885	8,570
Total Capital	1,155	1,132	1,023	1,067	1,180	1,176	1,030	1,225	1,033	986	11,008
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Maintenance	561	556	568	526	501	587	578	597	607	598	5,679
Attachments	336	289	271	323	353	270	287	274	268	286	2,957
Subtotal Non-ICM	897	845	839	849	854	857	865	871	875	884	8,636
ICM Eligible	323	308	186	224	332	317	171	372	155	152	2,540
Subtotal Customers	1220	1153	1025	1073	1186	1174	1036	1243	1030	1036	11,176
Synergy Investments	11	36	53	37	13						150
Total	1231	1189	1078	1110	1199	1174	1036	1243	1030	1036	11,326