EB-2017-0306/307 EGD and Union MADDS and Rate Setting Applications

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Energy Probe Compendium May 14/15, 2018

PANEL 4 NERA

REFERENCES

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TOPICS

- **IR Responses**
- **Service Life**
- **Output Quantity**
- **Productivity Growth Trends**
- **Capital Trackers, (K factors)**
- **Stretch Factor**

Filed: 2018-03-23 EB-2017-0306/EB-2017-0307
Exhibit C.EP.31 Page 1 of 2
ENBRIDGE GAS DISTRIBUTION INC. AND UNION GAS LIMITED
Answer to Interrogatory from
Energy Probe Research Foundation ("EP")
Rate Setting Application
Reference: Exhibit B, Tab 2, Page 4
Preamble: Recent Evidence provided by Pacific Economics Group summarizes some recent Productivity Studies and trends in X factors (provided as Attachment to this Interrogatory).
Question:
a) Please confirm Dr. Makholm is familiar with these recent studies
b) Please explain why Dr Makholm's evidence does not provide a summary of these studies.
c) Confirm that the current AUC IRM Price Cap Plans established an X factor of 0.3 % for both gas and electric utilities

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Productivity "X" Factor: Recent Trends

The negative trend in productivity is confirmed across multiple experts and sources

Year	StatCan MFP Utility Sector Multifactor Productivity	2012 AUC Proceeding NERA Results	2016 AUC Proceeding Brattle Update of NERA	2016 AUC Proceeding PEG Study for CCA	2016 AUC Proceeding Christensen Study	Christensen Eversource Industry TFP	PSE - Hydro One Ontario Industry TFP	Makholm EGD TFP Growth
2000	2.4%	2.1%	2.1%	1.0%	2.0%			1.9%
2001	2.9%	3.4%	3.4%	1.0%	3.2%			2.9%
2002	2.8%	1.2%	1.2%	1.7%	1.8%	-0.1%		2.2%
2003	3.0%	2.4%	2.4%	1.4%	2.1%	2.1%	0.8%	2.8%
2004	3.0%	2.8%	2.8%	1.4%	3.0%	1.9%	1.3%	3.3%
2005	2.8%	2.1%	2.1%	1.2%	2.2%	0.1%	2.2%	2.4%
2006	3.1%	2.5%	2.5%	0.0%	-2.2%	1.0%	0.2%	3.0%
2007	4.2%	0.5%	0.5%	0.0%	0.5%	-0.4%	1.5%	0.8%
2008	0.5%	-4.9%	-4.9%	0.2%	-4.4%	-2.3%	-0.6%	-4.9%
2009	6.7%	2.6%	2.6%	0.8%	3.7%	2.0%	-0.1%	2.9%
2010	1.5%		2.2%	0.4%	1.7%	2.2%	0.8%	2.1%
2011	1.0%		-4.5%	0.5%	3.9%	1.9%	-1.3%	-4.4%
2012	2.4%		-2.0%	1.2%	-2.0%	0.6%	-3.9%	-2.1%
2013	3.1%		-0.2%	0.0%	-0.6%	-0.2%	-4.5%	-0.4%
2014	1.9%		1.8%	-0.1%	1.7%	1.0%	-2.0%	1.9%
2015	2.1%					0.2%	-2.8%	-1.4%
Post-2000 Average	-1.1%	-0.7%	-0.9%	0.5%	-0.8%	-0.5%	-0.9%	-0.9%
Last 5 Years Average	-2.1%	-1.5%	-1.3%	0.4%	-1.3%	-0.5%	-2.9%	-2.0%

MRI for Hydro-Québec Distribution

PEG
Pacific Economics Group Research, LLC

Exhibit C.EP.31 Page 2 of 2

Page 2

Response

a) Dr. Makholm is familiar with the first study listed (his own in Alberta) and some familiarity with a number of the other studies (to they extent the employ his data set—i.e., the 2016 AUC studies by Brattle and Christensen Associates that the study presented before the Massachusetts DPU by Christensen Associates for Eversource.

b) **Dr. Makholm does not conclude that a survey or summary of such studies (whether using his basic data set or other data) would be a useful part of the evidence he presents in this case.**

c) Dr. Makholm's understanding is that **the AUC's current IRM Price Cap of 0.3% represents a combined X-factor and positive stretch factor for both electric and gas utilities.**

DR. MAKHOLM: At the moment for energy utilities, I do not know.

MR. BRETT: You do not know.

So of those states that you spoke of, and to your knowledge would they have typically had positive X factors?

DR. MAKHOLM: It depends on the time period. For the last X factor approved in Massachusetts for Eversource was the negative 1.3, not positive. Going back in terms of the ten years before, I think by and large they were positive X-factors.

MR. BRETT: What about stretch factors? Did they employ stretch factors?

DR. MAKHOLM: In some fashion they employed stretch factors, consistent with the imposition of a new regime, yes.

MR. BRETT: So in your sample that you are using of U.S. companies that you are working with, how many of them would have PBR regimes at the present time? It doesn't sound like very many.

DR. MAKHOLM: I think that's correct.

MR. BRETT: And why is that? Are the regimes primarily cost of service?

DR. MAKHOLM: Yes.

Exhibit JT2.3
Page 1 of 1
Plus Attachments
ENBRIDGE GAS DISTRIBUTION INC. AND UNION GAS LIMITED
Undertaking of Dr. Makholm
To Dr. Lowry
REF: Tr.2 p.35
To provide the average service life of Union and EGD assets on best efforts basis.

Response:

Please see Attachment 1 and 2 for the requested calculation of Union's and EGD's average service life of assets.

Union Calculation of average service list of distribution and storage assets

($Millions)	O.E.B. No.	2014 Actual 2014 Average	2014 Depn	2015 Actual 2015 Average	2015 Depn	2016 Actual 2016 Average	2016 Depn	2017 Actual 2017 Average	2017 Depn
Gas Plant in Service:									
Underground storage plant:									
Land	450	4.8	0.0	4.9	0.0	4.9	0.0	4.9	0.0
Land rights	451	32.0	0.7	32.0	0.7	32.0	0.7	32.0	0.7
Structures and improvements	452	61.1	1.5	61.7	1.5	62.2	1.6	64.9	1.6
Wells	453/4/5	89.6	2.2	89.9	2.2	90.4	2.2	92.5	2.3
Compressor equipment	456	238.8	6.4	240.0	6.4	255.4	6.8	373.3	10.0
Measuring & regulating equipment	457	56.2	1.7	56.6	1.8	58.3	1.8	69.2	2.2
Base pressure gas	458	35.2	0.0	35.2	0.0	35.3	0.0	35.9	0.0
Other equipment	459	2.4	0.5	2.4	0.5	1.2	0.0	0.0	0.0
Regulatory Overheads		11.6	0.3	12.4	0.4	12.6	0.4	13.6	0.4
Sub-Total		531.6	13.4	535.0	13.5	552.2	13.5	686.3	17.1
Distribution plant									
Land	470	14.6	0.0	15.0	0.0	15.3	0.0	16.0	0.0
Land rights	471	15.8	0.3	16.3	0.3	16.9	0.3	17.5	0.3
Structures & improvements	472	193.3	4.4	194.0	4.5	196.3	4.5	200.6	4.6
Services - metallic	473	214.9	6.4	220.7	6.6	224.9	6.7	227.1	6.8
Services - plastic	473	1196.9	30.4	1234.2	31.4	1271.5	32.3	1307.5	33.2
Regulators	474	89.9	4.5	94.7	4.7	101.3	5.1	108.2	5.4
House regulators & meter installatic	474	96.9	2.7	99.7	2.8	104.9	2.9	107.3	2.0
Mains - metallic	475	839.6	24.5	869.8	25.4	912.9	26.7	958.5	29.0
Mains - plastic	475	762.9	17.8	783.5	18.3	806.2	18.8	831.9	19.4
Measuring & regulating equipment	477	154.2	5.8	161.3	6.0	168.4	6.3	174.9	6.5
Meters	478	303.7	11.7	326.1	12.6	350.8	13.6	378.6	14.6
Regulatory Overheads		169.8	4.9	206.3	5.9	251.4	7.2	301.1	8.6
Sub-Total		4052.7	113.5	4221.6	118.5	4420.8	124.3	4629.2	130.5
Total		4584.3	126.9	4756.5	131.9	4972.9	137.7	5315.5	147.7
Weighted Average Depreciation Rate			2.8%		2.8%		2.8%		2.8%
Average Service Life			36.1		36.1		36.1		36.0

Filed: 2018-04-05
EB-2017-0306/EB-2017-0307
Exhibit JT2.3
Attachment 1

EGD Calculation of average service life of distribution and storage assets

$ Millions	EB-2015-0122 2014 Actual		EB-2016-0142 2015 Actual		EB-2017-0102 2016 Actual		Preliminary 2017 Actual	
	Avg. of Avg. Gross PP&E	Dep'n expense	Avg. of Avg. Gross PP&E	Dep'n expense	Avg. of Avg. Gross PP&E	Dep'n expense	Avg. of Avg. Gross PP&E	Dep'n expense
Distribution Plant								
Inactive services (102)	1.7	0.0	1.7	0.0	1.7	0.0	1.7	0.0
Land (470.00)	19.2	0.0	19.4	0.0	22.4	0.0	23.2	0.0
Land rights intangibles (471.00)	7.6	0.1	11.2	0.1	51.7	0.6	63.7	0.8
Structures and improvements (472.00)	127.4	7.9	124.2	6.5	123.8	6.8	136.0	8.7
Services, house reg & meter install. (473/474)	2401.5	55.0	2528.6	57.3	2667.2	61.1	2772.8	62.9
NGV station compressors (476)	3.2	0.2	3.3	0.2	3.5	0.2	3.6	0.2
Meters (478)	405.7	37.5	416.9	38.5	427.2	39.6	433.6	31.3
Mains (475)	3054.3	66.4	3229.6	70.6	3940.3	88.6	4275.0	95.6
Measuring and regulating equip. (477)	381.7	8.3	402.4	8.4	479.0	10.6	556.6	12.2
Sub -Total	6402.3	175.3	6737.3	181.6	7716.7	207.5	8266.2	211.7
Storage Plant								
Crowland storage (450/459)	4.2	0.1	4.2	0.1	4.2	0.1	4.2	0.1
Land and gas storage rights (450/451)	43.7	0.5	44.9	0.5	45.0	0.5	45.0	0.5
Structures and improvements (452.00)	15.8	0.3	16.6	0.1	25.9	0.5	30.0	0.6
Wells (453.00)	47.3	0.7	48.0	0.7	50.2	0.8	53.2	0.8
Well equipment (454.00)	10.0	0.6	10.1	0.6	10.5	0.6	11.1	0.6
Field Lines (455.00)	78.8	1.2	83.7	1.3	87.1	1.4	97.6	1.5
Compressor equipment (456.00)	107.4	2.9	112.1	3.0	117.6	3.1	125.1	3.3
Measuring and regulating equipment (457.00)	11.6	0.4	11.5	0.3	11.2	0.3	11.2	0.3
Base pressure gas (458.00)	40.9	0.0	39.4	0.0	33.4	0.0	33.4	0.0
Sub -Total	359.6	6.7	370.6	6.5	385.0	7.4	410.7	7.7
Total	6761.9	182.0	7107.9	188.1	8101.7	214.9	8676.9	219.4
Weighted Average depreciation Rate		2.7%		2.6%		2.7%		2.5%
Average Service life		37.2		37.8		37.7		39.5

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MR. SHEPHERD: Okay. Thank you.

The second question I have is, you were asked about your 33-year life, which comes from primarily electricity data, and what the lives were for Union and Enbridge, and we're going to find out what those were, and I want to ask a slightly different question, which is: If the average life, the weighted-average life, of Union's assets, let's say, is significantly different from 33 years -- I'm estimating it might be 37, for example -- does that have a material impact on your results? Or could that have a material impact on your results?

DR. MAKHOLM: By "results" being my ultimate conclusion?

MR. SHEPHERD: Yes.

DR. MAKHOLM: I would say no, and the reason for that is as follows. The -- I know, more than anybody else, having been doing this longer than anybody else, know the uncertainty associated with any one particular firm or company's data, and I write about the instability. I have a couple of references in my backup, as I refer to it, about that specific issue.

I put great stock and hold to be highly objective and credible large collections of data that allow those idiosyncrasies to average out. But to the extent that any one company is off of the average of a distribution life, I would have to look at that and say that it's an anomaly.

Exhibit C.EP.32 Interrogatory Response to Energy Probe

Filed: 2018-03-23 EB-2017-0306/EB-2017-0307 Exhibit C.EP.32 Page 1 of 2
ENBRIDGE GAS DISTRIBUTION INC. AND UNION GAS LIMITED
Answer to Interrogatory from
Energy Probe Research Foundation ("EP")
Rate Setting Application
Reference: Exhibit B, Tab 2, Page 33 and JDM-3 Tab 2 Figure 2
Preamble: A30. For the distribution industry I use sales volume as the output quantity. I create an output index by combining sales volume for several different customer categories as follows: Residential, Commercial, Industrial and Public. EGD provided sales volume (106 m3) data for roughly the same customer categories. However, I measure sales volume (106 m3) for Union using two customer categories, a General Service category and a Contract category.
Question:
a) Confirm that the options for output quantity are sales volume (MWh electricity or m3 gas) or number of customers. Please justify why sales volume rather than number of customers is appropriate in this case.
b) Did NERA/Dr. Makholm examine output factor growth using the number of customers? If so please provide this analysis.
c) Confirm that Enbridge and to a lesser degree, Union, have experienced declining average use per residential customer.
d) Confirm that the current Revenue Cap Mechanism for EGD rates is based on costs per customer.
e) Has NERA/Dr. Makholm analyzed how trends in declining average use affect output quantity and total factor productivity? If so please provide these data for the industry sample used in the TFP analysis. If not, please explain why.
f) Please discuss in detail, with mathematical analysis, how declining residential average use per customer affects output quantity and utility productivity. Specifically, confirm why Sales Volume is the appropriate output quantity, rather than number of customers.

Response
a) Sales volume and number of customers are two of the options for output quantity. The Alberta Utilities Commission also considered other measures in its PBR proceeding (see AUC Decision 2012-237, ¶392). Dr. Makholm recommended a kWh output index in that
Exhibit C.EP.32 Page 2 of 2
case, among the alternatives, and the AUC agreed agrees with his recommendation in the following way:

The Commission agrees with the experts in this proceeding that each possible output measure (for example, energy sales, number of customers, line miles, peak usage, etc.) or combination thereof has its own merits and disadvantages.
…
In light of this uncertainty, the Commission is not persuaded that NERA‘s output measure of kWh sold is an inferior output measure compared to the variety of alternatives proposed.
…
Overall, the Commission agrees … that NERA‘s output index measuring kWh sold is an acceptable measure to use for the purpose of calculating TFP growth for electric distribution companies (see AUC Decision 2012-237, ¶¶392-397).
b) No.

c) Both EGD and Union have been experiencing declining average use per customer.

d) Not confirmed, EGD's current rates are established using the OEB approved Custom Incentive Regulatory mechanism.

e) No. Any trends that affect output will show up in the measure of output included in the TFP growth calculation.

f) Because the number of customers does not appear in Dr. Makholm's TFP growth analysis, a decline in such a number does not affect his analysis. Please see the response to part a, above with respect to Dr. Makholm opinions and results of using sales quantities at the output index

MR. SHEPHERD: The -- I wanted to follow up on that. I am actually now at a -- completely out of synch here, but that's okay. You, in your articles, appear to say that productivity, in general -- and in fact, you say that this is generally believed by a lot of academics in the field -- sort of reverts to the mean over time. If you get a large enough piece of data the productivity will normally end -- for an industry end up at roughly the same place eventually.

Is that -- am I understanding that roughly correctly?

DR. MAKHOLM: Let me put it a little differently, and I think a couple of data -- a couple of IR responses where I went on and on and on about things that I say I did in another study in Alberta.

One of the things that I said was that out there in the world there is a productivity growth trend for any particular industry: telecommunications, electric and gas utilities, whatever. And we're endeavouring to find out what that is with the data that we have.

And to find out what that number is out in the world, if we have a big enough data set and use the proper methods with that data set, we do the best job of determining what that number is in the world. It is a real number out there that reflects industry productivity growth. And that's what we're after.

And it could be -- if it's not zero, it could be high, like telecom companies in the 1990s, at 3 to 5 percent, pretty high, but that was the number for that industry in the '90s.

What I've concluded here is that the number has settled down to be zero for electric and gas distribution in this day and age.

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MR. SHEPHERD: Sorry, productivity growth, sorry, you're right, the productivity growth, and you say as long as that continues those inflation numbers are right.

DR. MAKHOLM: No, and it doesn't have -- as long as that continues just doesn't work into that. It's that the -- as we measure the relative productivity of the industry vis-a-vis the economy, we have concluded that there's no reliable difference, hence the X is zero, hence you can use the published inflation index as a way of lengthening regulatory lag.

I'm not saying that it has the ability to predict the future. There is nothing about future prediction here --

MR. SHEPHERD: No, I --

DR. MAKHOLM: -- it only is whether or not you can use the published inflation indices as the vehicle by which to lengthen -- to help lengthen regulatory lag. That's all it does.

MR. SHEPHERD: You've said that in your past study period the inflation figure and the cost trajectory of the utilities is the same, and there is no -- there is no difference, there is no productivity difference; right? That's essentially what you've concluded?

DR. MAKHOLM: Yes.

MR. SHEPHERD: And so you're saying --

DR. MAKHOLM: Growth.

MR. SHEPHERD: Then we can apply that into the future. You are not predicting --

DR. MAKHOLM: No, I'm not saying you can apply that into the future. I'm saying that the conclusion comes that you can use the published inflation indices to take us into the future. That's what it says.

MR. SHEPHERD: And that is only true if the future cost levels are the -- or the cost growth is the same as the past; right?

DR. MAKHOLM: No, all I've done is to confirm the idea of using the published inflationary indices going forward to lengthen regulatory lag. I'm not predicting future costs, I'm not saying that the future is the same as the past.

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Mr. Shepherd

You've commented in your article here -- this is attachment to SEC.65, and I'm looking at page 41 of the article, page 9 of the attachment -- you've commented There, and you've commented in your other writing as well, that the K-factors or capital trackers of various types are intended to capture capital expenditures that are unusual, right? That the routine capital expenditures aren't part of that sort of process in your view, is that right?

DR. MAKHOLM: No, I think that's a little too specific.

MR. SHEPHERD: All right.

DR. MAKHOLM: They are capital expenditures that otherwise aren't dealt with under the regulatory regime.

In that respect, unusual, I can agree with.

MR. SHEPHERD: So when you say -- sorry, the clip is in the way.

When you say at the bottom of page 9 and the top of page 10:

> **"Numerous regulatory bodies have adopted infrastructure trackers for specific capital expenditures, and that is the approach we would recommend. The capital expenditures that are candidates for such trackers must be comparatively unusual and narrowly defined (such as cast-iron pipe replacement for gas distributors or specific aged infrastructure replacement for electric distributors)."**

Can you track that quote to what you've just told me?

DR. MAKHOLM: Sure. If you look further back up in that same paragraph, you will see that "such provisions are known as

K-factors and help ensure that utilities cover costs for necessary and prudent system upgrades."

That's in the same paragraph and that gives context to the whole rest of the paragraph, which is that we are living in the Brandeisian prudence sense.

The companies have the public to serve and if the public requires, through a new subdivision or a new extension, or a upgrade of service or increased demand, new facilities to be invested in to serve them, prudence would require that we take a look at them and find a way to track those costs.

We don't make companies serve new users without some confidence that they -- that the capital they expand for that purpose is well-tracked, and a return will flow from it. That's the basic regulatory bargain.

So nothing about what the end of the paragraph contradicts what I wrote earlier in the paragraph with respect to prudence.

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DR. MAKHOLM: I have two responses, if I could. One is to say I answered that exact question that I put to myself on Q-and-A 24 in my testimony. I said, "What about the merger of EGD and Union, isn't that a transition," in quotes, "that conceptually could lead to the consideration of a stretch factor."

And I went on at length over the course of the next page or so to describe why not, why my answer was no in that instance.

Returning to a prior question of yours, Mr. Brett, you had said that this transition bit seems to be a bit vague and nuanced, not aligned; you said not a bright line. And I would suggest that that's not so because examining the transcripts and the proceedings in Alberta, that commission treated it as a bright line. And unless they could find a transitional regulatory regime element, they didn't have the basis for the stretch factor for the second period.

They realized in their first plan it was a new kind of restarted regime in the way we discussed, and they had a stretch factor associated with that.

In the second regime, they also had a stretch factor, but because they changed something. They changed the nature of the capital formula to include incentive activities in the capital formula, and they said so. And they said that the reason for their stretch factor was exactly that.

So for them, in the justification for their decision, they do treat it like a bright line, and I do, too.

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MS. GIRVAN: I'm still struggling with the fact of why isn't a stretch factor appropriate.

DR. MAKHOLM: It is a derivative of a change in a regulatory regime, that's why.

And if the regulatory regime hasn't changed stretch, defined the way I have done so, has no place.

Exhibit K____________

Line	Description (all $ in millions)	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	Cumulative		Source (from EB-2017-0306 where applicable)
1	Stand-alone cost and rate proposal	2,531	2,657	2,767	2,850	2,932	3,014	3,103	3,174	3,268	3,351	29,647		Exhibit B Tab 1 page 20
2	Amalco rate proposal	2,530	2,630	2,709	2,788	2,872	2,964	3,054	3,144	3,234	3,314	29,239		Exhibit B Tab 1 page 20
3	Ratepayer benefit	1	28	59	62	60	50	49	30	34	38	411		Exhibit B Tab 1 page 20
4	Forecast savings	3	38	63	70	81	85	85	85	85	85	680		Exhibit B Tab 1 attachment 12
5	Merger Capital (revenue requirement)	-1	-4	-9	-15	-18	-18	-18	-17	-17	-16	-133		Exhibit C.FRPO.1 Attachment 1 page 23
6	Forecast actual cost assuming merger	2,529	2,623	2,713	2,795	2,869	2,947	3,036	3,106	3,200	3,282	29,100		= line 1 - line 4 - line 6
7	Shareholder Benefit	1	7	-4	-7	3	17	18	38	34	32	139		= line 1 - line 6
8	Total % savings from status quo											1.85%		=(line 4+ line 5) / line 1%
9	% Savings to ratepayers											1.39%	75%	= line 3/ line 1 %
10	% Savings to shareholder											0.47%	25%	= line 7/ line 1 %
11	AMALCO rate proposal incl .3 stretch	2,523	2,616	2,688	2,760	2,837	2,921	3,002	3,083	3,164	3,234	28,829		FRPO 11a with ICM Impact Calculations_2018-0402, stretch deducted from inflation assumptions
12	Difference	6.64	13.51	20.65	27.85	35.34	43.44	51.52	60.68	69.99	80.07	410		= line 2 - line 11

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MR. QUINN: You continue to use the scholarly sense, and I respect that you have a vast knowledge of what's out there. But in where we are, in a regulatory context, has there ever -- to your knowledge, has there been a submission of some evidence, some data that looked at productivity before and after the merger in a way that assisted the regulator with establishing bounds between the investor and the customer?

DR. MAKHOLM: No.

MR. QUINN: You are not aware of any proceeding that had that type of data or evidence?

DR. MAKHOLM: That's correct.

Panel 5: Dr. Mark Lowry: Pacific Economics Group PEG - Board Staff

Evidentiary References.

EB-2017-0306/0307 L1.EGD/Union.8 Interrogatory Response [Comp. Page 21]
EB-2017-0306/0307 PEG Report Exhibit M1 Section 7.4 Page 53 [Comp. Page 22]
EB-2017-0306/0307 IR L1.EGD/Union 2 Part f) [Comp. Page 22]
EB-2017-0306/0307 PEG Report Exhibit M1 Page 48 [Comp. Page 23]
EB-2017-0306/0307 Exhibit K2.3 [Comp. Page 24]
EB-2017-0306/0307 PEG Report Exhibit M1 Section 7.3. page 52 [Comp. Page 25]
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Topics

- **Retainer, Sample of Utilities and COS and IRM/PBR regulation**
- **Industry-economy productivity differentials under IRM/PBR**
- **Declining Average Use for General Service Customers**
- **Benchmarking Studies**
- **0.3% Stretch factor.**
- **The Treatment of Capital under the Price Cap Formula**
- **Z Factors.**

L1.EGD/Union.8 – TFP output measure

References:

a. PEG Evidence, April 11, 2018, page 33:

"Finally, we replaced NERA's volumetric output index with the number of customers served."

b. Alberta Utilities Commission Rate Regulation Initiative, Proceeding 566, Decision 2012- 237, September 12, 2012, paragraphs 378:

"378. Accordingly, the Commission finds that, in the absence of superior TFP data for the gas distribution industry, NERA's TFP study is an acceptable starting point for determining a productivity estimate for Alberta gas distribution companies."

Preamble:

The companies want to confirm Dr. Lowry's view on output specification.

Question:

When Dr. Makholm and Dr. Lowry both appeared in the AUC Proceeding 566, confirm that in AUC Decision 2012-237, the AUC agreed that the use of a volumetric output index was appropriate for measuring productivity for the gas distribution industry. If not confirmed, explain why.

Response: The following response was provided by PEG.

Dr. Lowry cannot confirm this statement. He believes that the AUC glossed over the issue of whether NERA's volumetric output index was appropriate for measuring gas utility productivity. The AUC did acknowledge that the number of customers was the most appropriate output variable when calibrating the X factor for a revenue per customer indexing mechanism.

> During the hearing, Dr. Lowry also explained that since under a revenue-per-customer cap plan, a company's revenues are driven by customer growth and are largely insensitive to the amount of energy sold, the number of customers is the relevant output measure to use for TFP studies used in a revenue-per-customer cap PBR plan. In contrast, under a price cap plan, a change in the amount of energy sold has an immediate effect on a company's revenues, and thus the use of a volumetric output measure is justified. Accordingly, the CCA argued that output measures that place a heavy weight on volumetric and other usage should be used to determine the output index for TFP studies used in the context of a price cap PBR plan, while the number of customers should be used to determine the output index for TFP studies used in the context of a revenue-per-customer cap PBR plan. NERA agreed with this logic.[12] [footnotes omitted] . . .
>
> . . . The Commission agrees with Dr. Lowry and his colleagues at PEG that for revenue-per-customer cap plans, the number of customers, rather than a volumetric output measure, is the correct output measure for a TFP study.

[12] AUC Decision 2012-237, *op. cit.*, p. 80.

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7.4. Other Recommendations

Here are some other recommended modifications to the Applicants' proposal.

- An IPI is consistent with 4[Th] GIRM and sidesteps the need for a complicated input price differential calculation such as NERA provided. The OHS and GD capital cost specifications that NERA and PEG have used in this proceeding are very different from the methodology the Board uses to calculate capital costs in rate applications. This reduces the relevance of input price differential calculations that might be made using GD or OHS.
- If the OEB approves the Normalized Average Consumption/average use adjustments and LRAMs, the number of customers should be used in supportive TFP calculations to calibrate the X factor.
- The materiality threshold for Z factors plays an important role in IR. It reduces regulatory cost and can increase cost containment incentives.
- The proposed materiality threshold for the Z factor is low. A higher threshold is warranted that is appropriate for the Amalco's large size. The threshold should be escalated for PCI and customer growth.

Response To IR L1.EGD/Union 2 Part f)

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affect the *level* of utility cost do not always affect the *trends* in their costs. This is not, however, an argument against considering the level of a company's *cost inefficiency* when setting its stretch factor. Change in X inefficiency (defined as distance from the efficiency frontier) is well known to be a driver of productivity growth. A reduction of X inefficiency is more likely the higher is the current level. The existence of *initial* cost-level inefficiencies is, of course, part of Dr. Makholm's rationale for assigning stretch factors in first-generation PBR plans. If the initial level of cost inefficiency were zero there would be no need for a stretch factor.

f) Dr. Lowry confirms that the Commission rendered this judgement. He disagrees with this policy and believes that other regulators have better policies. Benchmarking has been used to set stretch factors by regulators in several jurisdictions, including Ontario, New Zealand, Vermont, and Dr. Makholm's home state of Massachusetts. A second group of regulators, largely in Europe, have occasionally added a component similar to a stretch factor in IR plans designed to reflect the inefficiency of poorly performing utilities in benchmarking studies. Countries whose regulators have incorporated such "efficiency catch up" terms as part of an X factor include Mexico, Denmark, Austria, the Netherlands, Finland, Germany, and Norway.

second generation or later IR plans in testimony for several utility clients.[70] Hydro One Networks, Ontario's largest power distributor, is proposing a 0.45% stretch factor in its current IRM proposal.[71]

Since the Applicants have not submitted benchmarking evidence, a 0.30% stretch factor seems in order for the Amalco. In the 4th GIRM this is the standard stretch factor for Ontario power distributors with average cost performance. Also, in EB-2016-0152, OPG proposed, and the OEB approved, a 0.30% X factor for the hydroelectric generation payment amounts Price Cap plan, on the basis of cost benchmarking evidence of how OPG compared with a sample of other hydroelectric generators filed in that proceeding.

6.2 X Factor

Our review of the assembled productivity evidence reveals the following facts.

- The TFP trends of sampled U.S. gas utilities over the 1999-2016 sample averaged **-0.23%.**
- When Dr. Makholm's research was corrected and upgraded to be more pertinent to the Applicants' IRM proposal, the TFP trends of sampled U.S. power distributors averaged **+ 0.49%** from 2001-2016.
- PEG obtained a similar **+0.23%** average trend in the TFP of U.S. power distributors from 2001 to 2014.[72] OM&A productivity growth averaged **0.40%** while capital productivity growth averaged **0.18%.**
- The IRM favors the Applicants in many respects. For example, the company will be compensated for a substantial portion of its capital revenue shortfalls.

Based on the assembled evidence, we recommend a **0.0%** base TFP trend for the Amalco. Adding this to a 0.30% X factor, we recommend a **0.30%** X factor.

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[70] See, for example, his X factor recommendations for Central Maine Power in 2007 and Gaz Metro in 2012. A full listing of Dr. Lowry's X factor recommendations for clients during the 2006-2015 period were detailed in Alberta Utilities Commission Proceeding 20414, Exhibit 20414-X0205 (CCA-EDTI Attachment 1b).

[71] EB-2017-0049, Exhibit A, Tab 3, Schedule 1, p. 21.

[72] Lowry, M.N., Deason, J., and Makos, M., "State Performance-Based Regulation Using Multiyear Rate Plans for U.S. Electric Utilities,", Lawrence Berkeley National Laboratory, July 2017.

Exhibit K____________

Line	Description (all $ in millions)	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	Cumulative		Source (from EB-2017-0306 where applicable)
1	Stand-alone cost and rate proposal	2,531	2,657	2,767	2,850	2,932	3,014	3,103	3,174	3,268	3,351	29,647		Exhibit B Tab 1 page 20
2	Amalco rate proposal	2,530	2,630	2,709	2,788	2,872	2,964	3,054	3,144	3,234	3,314	29,239		Exhibit B Tab 1 page 20
3	Ratepayer benefit	1	28	59	62	60	50	49	30	34	38	411		Exhibit B Tab 1 page 20
4	Forecast savings	3	38	63	70	81	85	85	85	85	85	680		Exhibit B Tab 1 attachment 12
5	Merger Capital (revenue requirement)	-1	-4	-9	-15	-18	-18	-18	-17	-17	-16	-133		Exhibit C.FRPO.1 Attachment 1 page 23
6	Forecast actual cost assuming merger	2,529	2,623	2,713	2,795	2,869	2,947	3,036	3,106	3,200	3,282	29,100		= line 1 - line 4 - line 6
7	Shareholder Benefit	1	7	-4	-7	3	17	18	38	34	32	139		= line 1 - line 6
8	Total % savings from status quo											1.85%		=(line 4+ line 5) / line 1%
9	% Savings to ratepayers											1.39%	75%	= line 3/ line 1 %
10	% Savings to shareholder											0.47%	25%	= line 7/ line 1 %
11	AMALCO rate proposal incl .3 stretch	2,523	2,616	2,688	2,760	2,837	2,921	3,002	3,083	3,164	3,234	28,829		FRPO 11a with ICM Impact Calculations_2018-0402, stretch deducted from inflation assumptions
12	Difference	6.64	13.51	20.65	27.85	35.34	43.44	51.52	60.68	69.99	80.07	410		= line 2 - line 11

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dependent on distributor capex forecasts. Regulatory cost was reduced thereby, and capex containment incentives were strengthened.[76]

A number of possible reforms to the capital cost tracker process were proposed by PEG in the Alberta proceeding which could also make sense in Ontario.

- The capex eligible for supplemental revenue could be subject to materiality thresholds and dead zones. Dead zones could also be added to materiality thresholds for Z-factored capex.
- The X factor could be raised in this and future plans to reduce expected double dipping and give customers a better chance of receiving the benefits of industry productivity growth in the long run. Knowledge that there is a price to be paid in the long run from asking for extra revenue now would strengthen the Amalco's capex containment incentives.
- Eligibility of capex for ICM treatment could be scaled back. For example, capex in the last year of the plan term could be declared ineligible because this involves only one year of underfunding.
- The ICM threshold can be escalated using the productivity trend of capital, while the X factor for OM&A revenue can reflect the productivity trend of OM&A. This could reduce the need for supplemental ICM revenue and make escalation of OM&A revenue more reflective of industry OM&A cost trends.

The OEB already embraces one of these strategies, since the ICM has a materiality threshold and dead zone. However, it is not clear whether the 10% threshold is appropriate, and under current ICM policy the Amalco would be funded for 100% of its marginal capex once it exceeds the threshold. An alternative is to disallow a fixed share of the total capex excess once capex exceeds the ICM threshold. Separate X factors for OM&A and capital revenue is another idea meriting consideration. If the OEB does not wish to deviate from the ratemaking treatment of capital in the 4th GIRM, the favorable treatment of capital should be kept in mind when considering other plan provisions.

[76] PEG nonetheless does not endorse the AUC's chosen approach.

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7.4. Other Recommendations

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