EB-2017-0306/7

ENBRIDGE/UNION MAADS/RATES

SEC CROSS-EXAMINATION MATERIALS

VOLUME 2

ENBRIDGE GAS DISTRIBUTION INC. AND UNION GAS LIMITED

Undertaking of Mr. Kitchen
To Mr. Garner

REF: Tr.2, p.31

To prepare a table comparing rates

Please see Attachment 1 for a comparison of Union North, Union South and EGD general service rate classes.

Comparison of General Service Rate Classes for Union North, Union South and Enbridge Gas Distribution

Line No.	Particulars (cents / m^3)	Union North - April QRAM (EB-2018-0104) Rate 01	Union North - April QRAM (EB-2018-0104) Rate 10	Union South - April QRAM (EB-2018-0104) Rate M1	Union South - April QRAM (EB-2018-0104) Rate M2	Enbridge Gas Distribution - April QRAM (EB-2018-0090) Rate 1	Enbridge Gas Distribution - April QRAM (EB-2018-0090) Rate 6
1	Applicability	Any customer in Union's North West and North East Zones who is an end user whose total gas requirements at that location are equal to or less than 50,000 m^3 per year.	Any customer in Union's North West and North East Zones who is an end user whose total firm gas requirements at one or more Company-owned meters at one location exceed 50,000 m^3 per year.	Any customer in Union South whose total consumption is equal to or less than 50,000 m^3 per year.	Any customer in Union South whose total consumption is greater than 50,000 m^3 per year.	To any Applicant needing to use the Company's natural gas distribution network to have transported a supply of natural gas to a residential building served through one meter and containing no more than six dwelling units.	To any Applicant needing to use the Company's natural gas distribution network to have transported a supply of natural gas to a single terminal location for non-residential purposes.
2	Monthly Charge	$21.00	$ 70.00	$ 21.00	$ 70.00	$20.00	$ 70.00
3	Delivery Charge	First 100 m^3 9.3485	First 1,000 m^3 7.8789	First 100 m^3 5.0691	First 1,000 m^3 5.0438	First 30 m^3 11.0799	First 500 m^3 10.3500
4	(declining block structure)	Next 200 m^3 9.1086	Next 9,000 m^3 6.3933	Next 150 m^3 4.8051	Next 6,000 m^3 4.9478	Next 55 m^3 10.4625	Next 1,050 m^3 8.2392
5		Next 200 m^3 8.7293	Next 20,000 m^3 5.7225	All over 250 m^3 4.1228	Next 13,000 m^3 4.7663	Next 85 m^3 9.9791	Next 4,500 m^3 6.7611
6		Next 500 m^3 8.3811	Next 70,000 m^3 5.1633		All over 20,000 m^3 4.4155	Over 170 m^3 9.6188	Next 7,000 m^3 5.8114
7		Over 1,000 m^3 8.0934	Over 100,000 m^3 3.0448				Next 15,250 m^3 5.3894
							Over 28,300 m^3 5.2834
	Cap-and-Trade (If applicable)						
8	Customer-Related Charge	3.3181	3.3181	3.3181	3.3181	3.3181	3.3181
9	Facility-Related Charge	0.0240	0.0240	0.0240	0.0240	0.0337	0.0337
	(Included in Delivery Charge on customer's bill)						
10	Storage Service Charges	Union North West 2.1960	Union North West 1.6552	0.7331	0.6483	Included in Delivery Charge	Included in Delivery Charge
11	(If applicable)	Union North East 6.3886	Union North East 4.5497				
12	Gas Transportation Service	Union North West 6.6669	Union North West 5.8356	Included in Commodity Charge	Included in Commodity Charge	Transportation 4.7525	Transportation 4.7525
13	(If applicable)	Union North East 2.7452	Union North East 2.5155			Transportation Dawn 1.0404	Transportation Dawn 1.0404
14	Commodity Cost of Gas and Fuel	Union North West 9.6085	Union North West 9.6085	12.3167	12.3167	9.4452	9.4665
15	(If applicable)	Union North East 12.5991	Union North East 12.5991				
16							
17	Annual Deferral Account Disposition	Price adjustments recovered/refunded prospectively over 6 months.	Price adjustments recovered/refunded prospectively over 6 months.	Price adjustments recovered/refunded prospectively over 6 months.	Price adjustments recovered/refunded prospectively over 6 months.	One time annual deferral adjustment recovered/refunded on actual consumption for the period.	One time annual deferral adjustment recovered/refunded on actual consumption for the period.
18	Gas Cost Adjustments	Price adjustments recovered/refunded prospectively over 12 month period.	Price adjustments recovered/refunded prospectively over 12 month period.	Price adjustments recovered/refunded prospectively over 12 month period.	Price adjustments recovered/refunded prospectively over 12 month period.	Gas Cost Adjustment Rider C recovered/refunded prospectively over 12 month period.	Gas Cost Adjustment Rider C recovered/refunded prospectively over 12 month period.

Line No.	Annual Residential Bill (Based on 2,200 m^3 consumption)	Union North West Bill ($)	Union North East Bill ($)	Union South Bill ($)	EGD Bill ($)
19	Delivery Charges	528	528	447	504
20	Gas Supply Charges	406	478	271	345
21	Total Bill	934	1,006	718	849

ENBRIDGE GAS DISTRIBUTION INC. AND UNION GAS LIMITED

Undertaking of Ms. Mikhaila
To Mr. Shepherd

a) To provide the 2028 calculations for J1.4, Attachment 1;
b) Similar to J1.4, Attachment 1, to provide the calculations for the other rate classes, for standard volumes.

Please see Attachment 1 for the estimated 2028 unit rates for Union South, Union North and EGD rate zone general service rate classes.

Please see Attachment 2 for the estimated bill impacts for 2019 and 2028 of small commercial customers with annual volume of 22,606 m^3 and 60,000 m^3.

Estimated 2028 Rates General Service Rate Classes for Union North, Union South and Enbridge Gas Distribution

Line No.	Particulars (cents / m^3)	Union North - Estimated 2028 (1) Rate 01	Union North - Estimated 2028 (1) Rate 10	Union South - Estimated 2028 (1) Rate M1	Union South - Estimated 2028 (1) Rate M2	Enbridge Gas Distribution - Estimated 2028 (1) Rate 1	Enbridge Gas Distribution - Estimated 2028 (1) Rate 6
1	Applicability	Any customer in Union's North West and North East Zones who is an end user whose total gas requirements at that location are equal to or less than 50,000 m^3 per year.	Any customer in Union's North West and North East Zones who is an end user whose total firm gas requirements at one or more Company-owned meters at one location exceed 50,000 m^3 per year.	Any customer in Union South whose total consumption is equal to or less than 50,000 m^3 per year.	Any customer in Union South whose total consumption is greater than 50,000 m^3 per year.	To any Applicant needing to use the Company's natural gas distribution network to have transported a supply of natural gas to a residential building served through one meter and containing no more than six dwelling units.	To any Applicant needing to use the Company's natural gas distribution network to have transported a supply of natural gas to a single terminal location for non-residential purposes.
2	Monthly Charge	$21.00	$ 70.00	$ 21.00	$ 70.00	$20.00	$ 70.00
3	Delivery Charge (2)	First 100 m³ 17.3281	First 1,000 m³ 11.7212	First 100 m³ 10.7860	First 1,000 m³ 7.2092	First 30 m³ 17.3730	First 500 m³ 13.7064
4	(declining block structure)	Next 200 m³ 16.9457	Next 9,000 m³ 9.7200	Next 150 m³ 10.3210	Next 6,000 m³ 7.0848	Next 55 m³ 16.3392	Next 1,050 m³ 10.7970
5		Next 200 m³ 16.3505	Next 20,000 m³ 8.3985	All over 250 m³ 9.1199	Next 13,000 m³ 6.3509	Next 85 m³ 15.5295	Next 4,500 m³ 8.7596
6		Next 500 m³ 15.8040	Next 70,000 m³ 7.6860		All over 20,000 m³ 5.9338	Over 170 m³ 14.9261	Next 7,000 m³ 7.4506
7		Over 1,000 m³ 15.3526	Over 100,000 m³ 4.9865				Next 15,250 m³ 6.8690
							Over 28,300 m³ 6.7229
	Cap-and-Trade (If applicable)						
8	Customer-Related Charge	3.3181	3.3181	3.3181	3.3181	3.3181	3.3181
9	Facility-Related Charge (Included in Delivery Charge on customer's bill)	0.0240	0.0240	0.0240	0.0240	0.0337	0.0337
10	Storage Service Charges	Union North West 2.6249	Union North West 1.9714	1.0359	0.9112	Included in Delivery Charge	Included in Delivery Charge
11	(If applicable)	Union North East 7.2113	Union North East 5.1188				
12	Gas Transportation Service	Union North West 6.6537	Union North West 5.8361	Included in Commodity Charge	Included in Commodity Charge	Transportation 4.8057	Transportation 4.8054
13	(If applicable)	Union North East 2.7769	Union North East 2.5576			Transportation Dawn 1.0416	Transportation Dawn 1.0414
14	Commodity Cost of Gas and Fuel	Union North West 9.6080	Union North West 9.6080	12.3162	12.3162	9.4584	9.4812
15	(If applicable)	Union North East 12.5986	Union North East 12.5986				
16							
17	Annual Deferral Account Disposition	Price adjustments recovered/refunded prospectively	Price adjustments recovered/refunded prospectively	Price adjustments recovered/refunded prospectively	Price adjustments recovered/refunded prospectively	One time annual deferral adjustment recovered/refunded on	One time annual deferral adjustment recovered/refunded on actual
18	Gas Cost Adjustments	Price adjustments	Price adjustments	Price adjustments	Price adjustments	Gas Cost Adjustment Rider C	Gas Cost Adjustment Rider C

Line No.	Annual Residential Bill (Based on 2,200 m^3 consumption)	Union North West Bill ($)	Union North East Bill ($)	Union South Bill ($)	EGD Bill ($)
19	Delivery Charges	695	695	575	627
20	Gas Supply Charges	417	506	271	347
21	Total Bill	1,112	1,201	846	974

Notes:
(1) Estimated unit rates calculated using assumptions provided at Exhibit J5.1, Attachment 2, Note 2.
(2) EGD's Delivery Rates include load balancing charges

UNION GAS LIMITED & ENBRIDGE GAS DISTRIBUTION

Calculation of 2019 and 2028 Estimated Total Bill for Union South, Union North and EGD Rate Zone Small Commercial Sales Service Customer

Line No.	Particulars	Approved 01-Apr-18 Total Bill ($) (1)	Estimated 2019 Rates: 2019 Total Bill ($) (2)	2019 vs 2018 Bill Impact ($)	Annual Increase from 2018 (%)	Estimated 2028 Rates: 2028 Total Bill ($) (2)	2028 vs 2018 Bill Impact ($)	Compound Average Annual Increase from 2018 (%) (3)
		(a)	(b)	(c) = (b) - (a)	(d) = (c)/(a)	(e)	(f) = (e) - (a)	(g)
	Small Commercial Customer - 22,606 m^3 annual consumption							
	Union South							
	Rate M1							
1	Total Delivery Charges	2,128.83	2,241.22	112.39	5.28%	3,344.94	1,216.11	4.62%
2	Total Gas Supply Charges	2,784.31	2,784.16	(0.15)	-0.01%	2,784.21	(0.10)	0.00%
3	Total Bill	4,913.14	5,025.38	112.24	2.28%	6,129.15	1,216.01	2.24%
	Union North							
	Rate 01 - North West							
4	Total Delivery Charges	2,901.79	3,027.11	125.32	4.32%	4,579.68	1,677.89	4.67%
5	Total Gas Supply Charges	4,175.66	4,173.06	(2.60)	-0.06%	4,269.51	93.85	0.22%
6	Total Bill	7,077.45	7,200.17	122.72	1.73%	8,849.19	1,771.74	2.26%
	Rate 01 - North East							
7	Total Delivery Charges	2,901.79	3,027.11	125.32	4.32%	4,579.68	1,677.89	4.67%
8	Total Gas Supply Charges	4,912.92	4,886.51	(26.41)	-0.54%	5,105.98	193.06	0.39%
9	Total Bill	7,814.71	7,913.62	98.91	1.27%	9,685.66	1,870.95	2.17%
	EGD							
	Rate 6							
10	Total Delivery Charges	3,130.93	3,203.95	73.02	2.33%	3,683.40	552.47	1.64%
11	Total Gas Supply Charges (4)	3,528.15	3,529.61	1.46	0.04%	3,563.20	35.05	0.10%
12	Total Bill	6,659.08	6,733.56	74.48	1.12%	7,246.60	587.52	0.85%
	Small Commercial Customer - 60,000 m^3 annual consumption							
	Union South							
	Rate M2							
13	Total Delivery Charges	6,196.79	6,204.62	7.83	0.13%	7,586.30	1,389.51	2.04%
14	Total Gas Supply Charges	7,390.00	7,389.60	(0.40)	-0.01%	7,389.70	(0.30)	0.00%
15	Total Bill	13,586.79	13,594.22	7.43	0.05%	14,976.00	1,389.21	0.98%
	Union North							
	Rate 10 - North West							
16	Total Delivery Charges	6,851.61	6,940.28	88.67	1.29%	8,901.83	2,050.22	2.65%
17	Total Gas Supply Charges	10,259.56	10,251.22	(8.34)	-0.08%	10,449.31	189.75	0.18%
18	Total Bill	17,111.17	17,191.50	80.33	0.47%	19,351.14	2,239.97	1.24%
	Rate 10 - North East							
19	Total Delivery Charges	6,851.61	6,940.28	88.67	1.29%	8,901.83	2,050.22	2.65%
20	Total Gas Supply Charges	11,798.58	11,739.60	(58.98)	-0.50%	12,164.97	366.39	0.31%
21	Total Bill	18,650.19	18,679.88	29.69	0.16%	21,066.80	2,416.61	1.23%
	EGD							
	Rate 6							
22	Total Delivery Charges	6,332.40	6,500.50	168.10	2.65%	7,576.27	1,243.87	1.81%
23	Total Gas Supply Charges (4)	9,364.28	9,368.15	3.87	0.04%	9,457.32	93.04	0.10%
24	Total Bill	15,696.68	15,868.65	171.97	1.10%	17,033.59	1,336.91	0.82%

(1) Current approved total sales service bill per April 2018 QRAM rates (EB-2018-0104 Union, EB-2017-0090 EGD), including cap-and-trade charges and excluding temporary credits/charges and prospective recoveries.

(2) The following assumptions were used to determine the estimate of the 2019 and 2028 total bill:

a) Annual Price Cap Index (PCI) of inflation of 1.73% less productivity of 0% applied each year, while maintaining the current monthly customer charge.

b) Annual Incremental Capital Module (ICM) and Y-Factor adjustments consistent with the assumptions provided in Table 10 and Table 11 at Exhibit C.FRPO.11. The ICM revenue requirement allocated to rate classes in proportion to rate base (excluding rate base associated with Union's ex-franchise rate classes).

c) Union's Normalized Average Consumption (NAC) and EGD's Average Use (AU) adjustment for 2019 based on current forecast of 2019 target and for 2020-2028 based on an assumption of 1% annual decline.

d) Includes one-time base rate adjustments of Union's Deferred Tax Drawdown and EGD's CIS and Customer Care Forecast Costs, Site Restoration Credit Tax deduct and Pension and OPEB costs.

e) No change to gas commodity and cap-and-trade charges.

(3) The compound average annual increase for 2028 is calculated relative to the 2018 total bill provided in column (a).

(4) EGD's total gas supply charges include commodity, transportation and load balancing charges.

Head to Head Dx Bill Comparison

Annual Volumes Assumed	40,000
Monthly Volumes Assumed	3,333

Union Rate 01					
	2018		2028		Increase
Component	Rate	Amount	Rate	Amount	
Fixed	$21.00	$252.00	$21.00	$252.00	0.00%
100	9.3485	$112.18	17.3281	$207.94	85.36%
300	9.1086	$218.61	16.9457	$406.70	86.04%
500	8.7293	$209.50	16.3505	$392.41	87.31%
1000	8.3811	$502.87	15.8040	$948.24	88.57%
0ver	8.0934	$2,266.15	15.3526	$4,298.73	89.69%
Subtotal Dx		$3,561.31		$6,506.01	82.69%
Cap & Trade	3.3181	$1,327.24	3.3181	$1,327.24	0.00%
	0.0240	$9.60	0.0240	$9.60	0.00%
Total		$4,898.15		$7,842.85	60.12%

Union M1					
	2018		2028		Increase
Component	Rate	Amount	Rate	Amount	
Fixed	$21.00	$252.00	$21.00	$252.00	0.00%
100	5.0691	$60.83	10.7860	$129.43	112.78%
250	4.8051	$86.49	10.3210	$185.78	114.79%
0ver	4.1228	$1,525.44	9.1199	$3,374.36	121.21%
Storage	0.7331	$293.24	1.0359	$414.36	41.30%
Subtotal Dx		$2,218.00		$4,355.93	96.39%
Cap & Trade	3.3181	$1,327.24	3.3181	$1,327.24	0.00%
	0.0240	$9.60	0.0240	$9.60	0.00%
Total		$3,554.84		$5,692.77	60.14%

Enbridge Rate 6					
	2018		2028		Increase
Component	Rate	Amount	Rate	Amount	
Fixed	$70.00	$840.00	$70.00	$840.00	0.00%
500	10.3500	$621.00	13.7064	$822.38	32.43%
1550	8.2392	$1,038.14	10.7970	$1,360.42	31.04%
0ver	6.7611	$1,446.88	8.7596	$1,874.55	29.56%
Subtotal Dx		$3,946.01		$4,897.36	24.11%
Cap & Trade	3.3181	$1,327.24	3.3181	$1,327.24	0.00%
	0.0337	$13.48	0.0337	$13.48	0.00%
Total		$5,286.73		$6,238.08	17.99%

Sources: 2018 from J2.2
2028 from J5.1

MR. SHEPHERD: Really? It is to provide a list of steps that have already been implemented to rationalize activities between the two utilities.

MR. MILLAR: Thank you.

UNDERTAKING NO. JT1.5: TO PROVIDE A LIST OF STEPS THAT HAVE ALREADY BEEN IMPLEMENTED TO RATIONALIZE ACTIVITIES BETWEEN THE TWO UTILITIES.

UNDERTAKING NO. JT1.6: TO PROVIDE THE CALCULATION OF SAVINGS.

MR. SHEPHERD: So I'm now on page 22 of this presentation. These numbers across in blue, that's the ICM-eligible projects, right?

MR. REINISCH: That's correct. That is the capex associated with ICM eligible projects.

MR. SHEPHERD: So in this presentation, you've said to your board of directors that we're seeking to extra funding for $2.5 billion of ICM projects over the ten years, is that right? I just added them up.

MR. REINISCH: Subject to check, yes, that is the approximate amount.

MR. SHEPHERD: And the next question is on 24. And you talked with your board about recovering distribution revenues via a fixed charge. Now you are not proceeding with that, right?

MR. REINISCH: No, there are no --

MR. KITCHEN: We are not proceeding with it in 2019, no. We are still evaluating.

MR. SHEPHERD: My next question is on 27. By the way,

ENBRIDGE GAS DISTRIBUTION INC. AND UNION GAS LIMITED

Undertaking of Mr. Kitchen
To Mr. Richler

REF: Tr.2, p.89

To provide a revised version of OEB Staff's chart at tab 3 of Exhibit K1.6.

In responding to this Undertaking the determination of a payback period for Amalco should include the contribution of savings that Amalco needs to meet each years allowed ROE (Shortfall). The sum of the Shortfall and the outlay of integration capital represent the total amount of savings that Amalco will have to achieve in order to meet the OEB allowed ROE over the deferred rebasing period (Cumulative Shortfall). Over the deferred rebasing period, Amalco forecasts that its costs to operate the business will exceed the revenues it receives under the Price Cap Index (PCI), including ICM rate adjustments and meeting the allowed ROE each year will be dependent on its achievement of forecasted integration related savings.

The following graphs show when Amalco has achieved sufficient savings to offset the Cumulative Shortfall (Crossover Point). The Crossover Point is where the Cumulative Shortfall and the forecasted Net O&M savings lines cross. The first graph shows the information provided in Exhibit K1.6, Tab 3 and adds a line to show the Applicants' perspective.

Two cases are provided to show a possible range of Crossover Points that Amalco may encounter over the ten year deferred rebasing period.

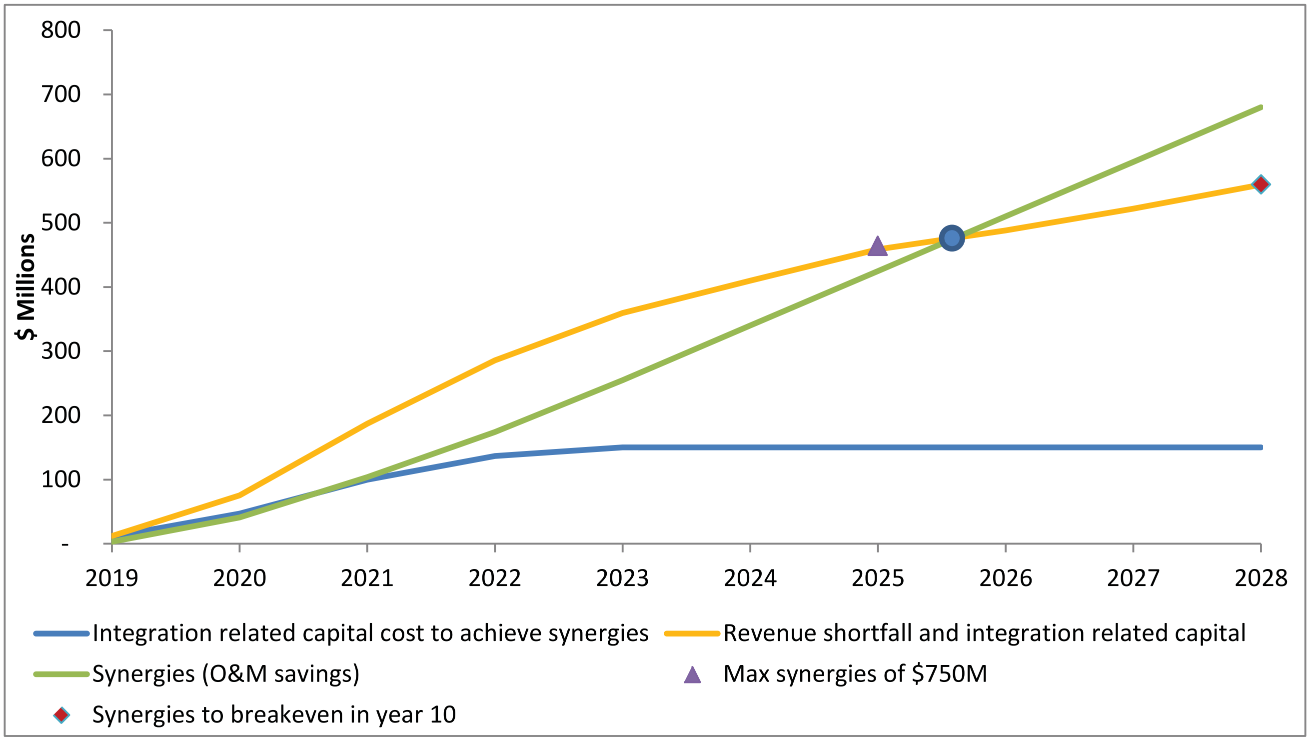
Case A: Base Case of $150 million capital investment and $680 million Net O&M savings
The yellow line shown in Graph 1 represents the Cumulative Shortfall for Amalco over the ten year term. The data for the Cumulative Shortfall line is located in row A.3 of Table 1.

The Cumulative Shortfall value is the sum of row A.1 and row A.2 in Table 1. These two rows represent Amalco's annual deficiency required to achieve that year's allowed ROE and that year's integration capital cost. For each of these items their source or calculation method is stated in the far right column of Table 1.

For Case A, the Crossover Point for Amalco is 7.5 years into the ten year term. The 7.5 year mark is when Amalco is forecasted to recover the cost to operate its base business and recover its integration capital outlay.

Graph 1 also shows two sensitivities for Case A. The triangle mark found at year 2025 on the yellow line identifies a payback period of 7 years should Amalco outlay $150 million in capital investment and achieve the maximum forecasted savings of $750 million.

The diamond mark found at year 2028 of the yellow line identifies that if Amalco spends $150 million in capital investment and achieves savings of $560 million, the payback period would be 10 years.



Graph 1: Case A with $150 million capital investment and $680 million Net O&M savings

A Base Case: $150M/$680M (capex/synergies)

Payback Net cash flow approach ($ Millions)	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	Source/Calculation
A.1 Revenue shortfall to meet allowed ROE	1	28	59	62	60	50	49	30	34	38	Exhibit B, Tab 1, Table 3
Cumulative	1	29	87	149	209	260	309	338	372	410	
A.2 Integration related capital cost to achieve synergies	11	36	53	37	13	-	-	-	-	-	Exhibit B, Tab 1, Attachment 12
Cumulative	11	47	100	137	150	150	150	150	150	150	
A.3 Revenue shortfall and integration related capital	12	64	112	99	73	50	49	30	34	38	Line A.1 plus Line A.2
Cumulative Shortfall	12	76	187	286	359	410	459	488	522	560	
A.4 Synergies (O&M savings)	3	38	63	70	81	85	85	85	85	85	Exhibit B, Tab 1, Attachment 12
Cumulative	3	41	104	174	255	340	425	510	595	680	
A.5 Gap - synergies vs revenue shortfall and integration related capital	(9)	(35)	(83)	(112)	(104)	(70)	(34)	22	73	120	Cumulative A.4 less Cumulative Shortfall (A.3)

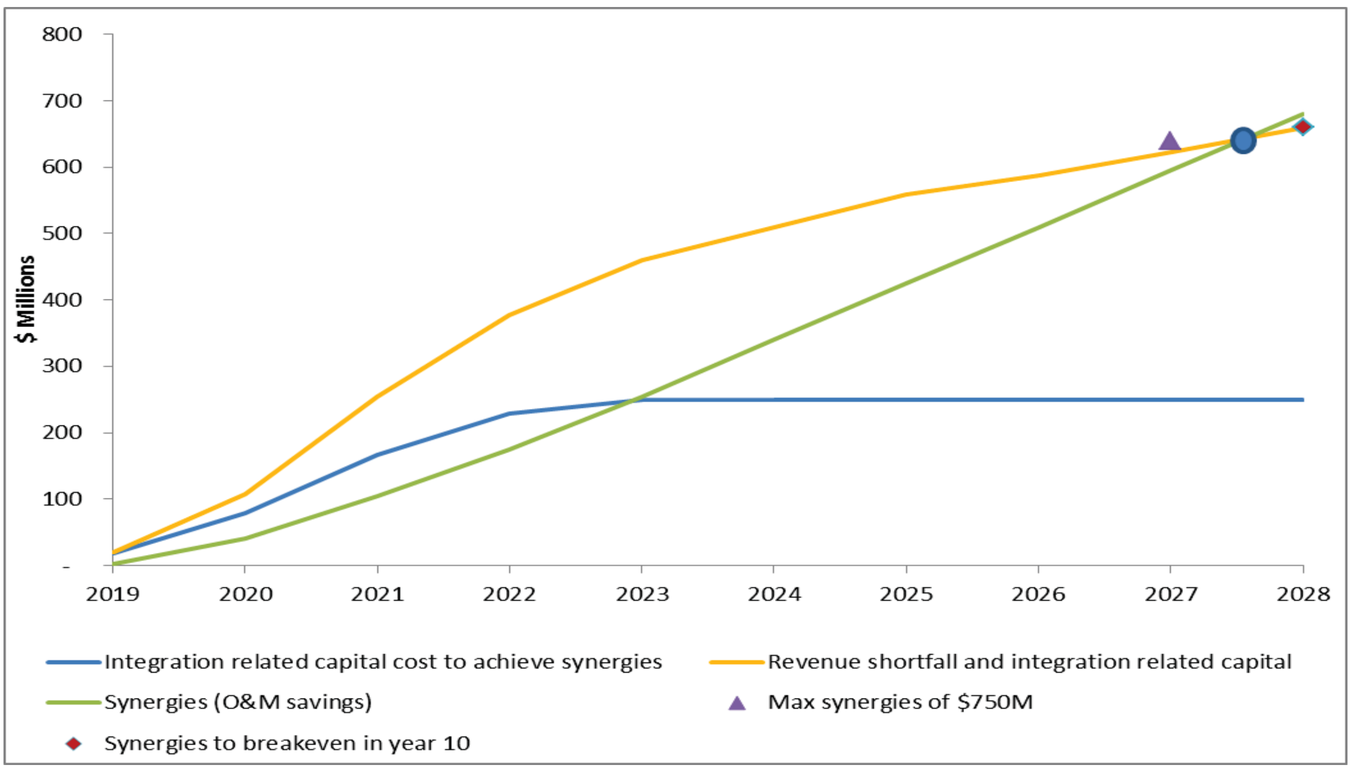
Table 1: Data and sources for Case A and Graph 1

Case B: Maximum Capital Investment of $250 million and $680 million Net O&M savings
Similar to Case A, the yellow line shown in Graph 2 represents the Cumulative Shortfall for Amalco over the ten year term. The data for the Cumulative Shortfall line is found in row B.3 of Table 2.

For Case B, the Crossover Point for Amalco is 9.5 years into the ten year term. The 9.5 year mark is when Amalco is forecasted to recover the cost to operate its base business and recover its integration capital outlay.

Graph 2 also shows two sensitivities for Case B. The triangle mark found at year 2027 identifies a payback period of 9 years should Amalco outlay $250 million in capital investment and achieve the maximum forecasted savings of $750 million.

The diamond mark found at year 2028 identifies that if Amalco spends $250 million in capital investment and achieves savings of $660 million, the payback period would be 10 years.



Graph 2: Case B Maximum Capital Investment of $250 million and $680 million Net O&M savings

B Scenario: $250M/$680M (capex/synergies)

	Payback Net cash flow approach (Millions)	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	
B.1	Revenue shortfall to meet allowed ROE	1	28	59	62	60	50	49	30	34	38	Exhibit B, Tab 1, Table 3
	Cumulative	1	29	87	149	209	260	309	338	372	410	
B.2	Integration related capital cost to achieve synergies	18	60	88	62	22	-	-	-	-	-	Exhibit B, Tab 1, Table 4 (profiled the same as the base case)
	Cumulative	18	78	167	228	250	250	250	250	250	250	
B.3	Revenue shortfall and integration related capital	19	88	147	123	82	50	49	30	34	38	Line B.1 plus Line B.2
	Cumulative Shortfall	19	107	254	377	459	510	559	588	622	660	
B.4	Synergies (O&M savings)	3	38	63	70	81	85	85	85	85	85	Exhibit B, Tab 1, Attachment 12
	Cumulative	3	41	104	174	255	340	425	510	595	680	
B.5	Gap - synergies vs revenue shortfall and integration related capital	(16)	(66)	(150)	(203)	(204)	(170)	(134)	(78)	(27)	20	Cumulative B.4 less Cumulative Shortfall (B.3)

Table 2: Data for Case B and Graph 2

MR. CULBERT: You are referring to the Enbridge Inc. corporate buying Spectra. We, EGD, have not purchased Union at all.

They are two separate utilities run in Ontario, regulated in Ontario. One entity owns the two companies; that's the extent of it.

MR. SHEPHERD: Isn't it your obligation as running a regulated utility to find every way you can to drive down cost?

MR. CULBERT: Our responsibility through the RRF, which the Board has various principles and goals, is to achieve -- continuous improvement is one of the goals. I agree with that.

What we're saying is we've both been through periods of -- fifteen years of incentive regulation. We've achieved many of the productivities that we can as separate entities. This is an opportunity to drive out even further synergies and savings by amalgamating.

Again, back to the Board's policy: The Board recognized when it amended its policy, in our view, in 2015, that there needs to be an incentive for organizations to consider amalgamating and driving out that highest level of savings.

If there is no incentive for the company -- it is like incentive regulation. We changed to incentive regulation because we thought cost of service wasn't necessarily producing the best result. Management wasn't doing things to the greatest extent that they could. That's my view of incentive regulation. I'm not sure if you'd take the same view. And we view this as being the same thing. If you want to drive out the greatest level of savings, this is the best model for doing that. It's a win-win situation. Ratepayers get a $410 million reduction in rates versus status quo. They don't have to pay for the $150 million in capital investment. The company has to drive out $680 million in synergies over that same term to generate on a net basis $120 million of potential savings and earnings to a degree. And then at the end of the ten-year term, the ratepayers get that additional $120 million put back to rates. It is a win-win situation. It incents us to do the best job possible. Without that incentive, we saw before, electricity didn't come forward until there was an incentive for them to do so. We're in the same boat.

MR. SHEPHERD: How is it in the interest of the ratepayers to propose to increase their rates 2.4 percent a year when you are assuming 1.7 percent inflation?

MR. CULBERT: Again, the price cap mechanism is the protection mechanism that the Board has figured is the appropriate method for setting rates during a consolidation. The price cap is that protective mechanism. That's what we're applying under.

MR. SHEPHERD: I didn't ask you that question. I asked you, how is it in the ratepayers' benefit to have their rates increase by about 140 percent of inflation for the next ten years? How is that in their interest?

MR. KITCHEN: Mr. Shepherd, the 2.4 percent that you year basis are getting larger, relative to the investment. I'm just talking about the first five years for now.

So effectively, you are not out of pocket cash at any point during that five-year period. And in fact, according to this table, which is your best estimate as you said in the technical conference, you are -- you are always in-pocket, essentially. You have excess cash-flow in 2020 of a million, in 2021 -- I'm trying to read my writing here, roughly 11 in 2022, 33 and 2023, 68 million.

So over the five-year period, you're recovering -- would you agree with me that you're recovering -- just looking at the five years for a moment, you are recovering your $150 million outlay and then you're also recovering an additional, subject to check, about 102 million.

So that's what's happening on a cash basis, right?

MR. REINISCH: Subject to check, I think it's about 155 million.

MR. BRETT: I understand. I may be a million out here. I'm not a -- it has been a long time since I studied mathematics.

MR. REINISCH: Sorry, Mr. Brett, I did want to add one thing, though. These are nominal cash amounts.

MR. BRETT: All right. These are nominal. They're all nominal, both the costs and the savings?

MR. REINISCH: That is correct.

MR. BRETT: Okay. So the question...

MR. CULBERT: Pardon me from for jumping in, Mr. Brett. I've said this before. These are also relative, these projections, to the baseline stand-alone scenarios that the company provided in table 3 of its analysis.

So the savings we have to generate -- I know I've said this numerous times. First, we have to generate savings up to $410 million just to get back to where we would have been at the start on a stand-alone basis. These aren't $608 million --

MR. BRETT: You're broadening the scope of this discussion substantially. You have the right do that, of course. I apologize for interrupting you. Do you want to carry on?

MR. CULBERT: I just wanted to make sure we are clear on what this represents.

MR. BRETT: And I'm speaking only of this construct that you have of we'll make these investments of such and such, and we'll garner savings of such and sufficient over the five-year period and we'll take the risk; we, the utility, will take whatever the risk is on this.

It looks like the risk-reward ratio on this particular table is pretty handsome. But let me ask you this, this is really... given that cash-flow and given that return picture, if I just look at this chart, why would you -- let me ask it this way. My sense of what your -- of why you're seeking the ten-year period in this case is really that in light of your analysis of the Board's guidelines and applying them to the gas industry, you're taking this ten-year approach because it's on offer to you, right?

MR. KITCHEN: Sorry, I couldn't hear that last part of that placeholder relative to changes in gas and storage values, et cetera, so this number would have been at a point in time. It's likely a different number. I can undertake to provide that number from the 2018 Board-approved.

MR. SHEPHERD: That would be useful. Please.

MR. CULBERT: Okay.

MR. RITCHIE: JT1.1.

UNDERTAKING NO. J1.1: TO PROVIDE THE FINAL FIGURES FOR 2018 RATE BASE IN THE EB-2012-0459 CASE.

MR. SHEPHERD: And it is adjusted because -- you didn't have any capital trackers, so you wouldn't have had any additional rate base other than what was in the custom IR except for gas supply, right?

MR. CULBERT: That's correct. Board-approved, what our capital expenditure forecast was for the five years. To the extent there were small implications in the working cash element of rate base because O&M was approved at a different level than the Board, so there are small implications in the working capital, but for the most part it is gas and storage value differences that would have occurred.

MR. SHEPHERD: So this 6152 could actually be far off.

MR. CULBERT: It's not materially different. Again, I'll provide the number for 2018.

MR. SHEPHERD: Well, so the reason I ask is this: I'm looking at this and I'm saying, well, one of the things that happens is if you don't rebase then that difference, that $550 million difference, doesn't get into rate base for another ten years.

MR. CULBERT: Well, it gets into rate base from an actual perspective, that the reconciliation or the forecasting that we did for the stand-alone was based off of 2018 rates in the price cap, but the stand-alone calculations were premised off of whatever our forecast capital expenditures and actuals have become through the period. That's the start point for our 2019 stand-alone scenario.

MR. SHEPHERD: So your stand-alone scenario assumes that you get to add all this difference in rate base into rate base in 2019.

MR. CULBERT: Yes, it assumes that whatever we have spent that has gone through scrutiny inside of our ESM applications where earnings were shared with ratepayers, et cetera, is the rate base that, in effect, has been approved and used for earnings sharing purposes and therefore should be used for rate-setting purposes going forward, yes.

MR. SHEPHERD: Awesome, but then your Amalco proposal doesn't add that into rate base, does it?

MR. REINISCH: That's correct.

MR. SHEPHERD: So you lose that $550 million for ten years, right?

MR. REINISCH: We defer adding that to cost recovery through rates for ten years.

MR. SHEPHERD: That's $450 million. Over those ten years that's $450 million, right?

MR. REINISCH: That is correct. It is a significant drag on earnings.

MR. SHEPHERD: So you are claiming that you've proposed to the Board that you are going to spend all this money to amalgamate and to get all these efficiencies and you are going to -- you are going to share earnings later and all that stuff, and you are going to give up $450 million of rates, in addition to everything else that might be there, because that doesn't sound like the Enbridge I know.

MR. REINISCH: So again, when you look at it as an overall proposal, rather than isolating a single item such as rate base for EGD, you have to take into consideration all of the pluses and minuses.

Enbridge Gas Distribution has lowered their O&M expenses through this IRM, which has helped generate excess earnings above allowed ROE. Again, the decision to defer rebasing means that those costs are not rebased in 2019.

So in a lot of ways those costs are what are being used to offset the capital costs that aren't going to be recovered for ten years.

So again, overall it is a balanced approach that provides, again, the savings to ratepayers, again through not rebasing the capital, as opposed to rebasing everything.

MR. SHEPHERD: Is there somewhere in the application a breakdown of the -- you say the ratepayers are going to get $410 million of savings, right?

MR. REINISCH: That's correct.

MR. SHEPHERD: Is there a breakdown somewhere of what that's coming from, a certain amount is coming from lower rate base and a certain amount is coming from the fact -- or, sorry, from the fact that they're not going to have to pay the higher rate base and a certain amount is coming from the lower O&M and so on.

Do you have -- is there a breakdown like that somewhere where we could get to the 410 million?

[Witness panel confers]

MR. REINISCH: So the challenge that we're having is, is effectively the 410 is derived from comparing two different pricing structures.

One pricing structure you have a custom IR for both utilities, so therefore you have effectively all of your costs, and then that generates a revenue requirement which is converted to the implied rates that are recovered from customers.

Within the MAADs framework it is a deferred rebasing, which is a price cap, so you have a starting point for rates, and then you inflate them each year, adding any incremental capital that would be approved through the ICM mechanism, so it is very difficult to sort of give you a breakdown of that 410 into the different component parts, because again, the base for creating the $410 million is the delta between those two lines.

MR. SHEPHERD: I understand that, but we know what 450 million of it is right now, right? We just talked

Gives and Gets Summary

"Gives"		
Category	**Initial**	**10 yr.**
$457 million Opening Rate Base not included in costs recovered		
Higher allowed ROE not included in costs recovered		
Merger Integration Investments for account of shldr.		

"Gets"		
Category	**Initial**	**10 yr.**
No clawback of overearnings on rebasing		
Merger Integration savings		
GTA Reinforcement Overspend not reviewed		
No stretch in X factor		
Growth in customer revenues greater than incremental costs		
Gains on property sales for account of shareholder		

"Neutrals"		
Category	**Initial**	**10 yr.**
Capex in excess of formula/ICM recovered		
Base rate adjustments		
Inflation factor in rates		
Zero productivity		
Incremental costs driven by customer growth recovered		

ENBRIDGE GAS DISTRIBUTION INC. AND UNION GAS LIMITED

Answer to Interrogatory from
Federation of Rental-housing Providers of Ontario ("FRPO")

Rate Setting Issues List – Issue No. 1

Reference: B1, TAB 1, pg. 20-21, Table 3

Preamble: We would like to understand better how the figures in Table 3 were developed.

Question:
Please provide all working sheets that contributed to the aggregated numbers in Table 3.

a. Please include all assumptions for both the amalgamated company and the separate utilities.
b. Please describe how the costs were rebased for each utility for 2019?
c. What stretch or productivity factors were assumed for each utility in calculating the costs for the individual utilities over the ten year period?
    i. What were the assumptions and methodology behind those figures?
d. Please explain why starting in 2023, the costs for the amalgamated company increase more than the two separate companies for each of the last 6 years.
    i. What drives that effect?

Response

a) Assumptions used are provided in the tables on the following pages:

a. Assumptions for Enbridge Gas Distribution (Stand-alone)

Table 1

(i) EGD Assumptions	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
1. Distribution Revenues										
1.1 Customer Additions	29,263	28,995	28,169	27,690	27,396	26,926	26,218	25,611	25,397	25,251
1.2 Escalation factor:										
1.2.1 GDPIPI	1.73%	1.73%	1.73%	1.73%	1.73%	1.73%	1.73%	1.73%	1.73%	1.73%
1.2.2 Productivity factor	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
1.2.3 Growth factor	0.93%	0.92%	0.84%	0.87%	0.84%	0.82%	0.80%	0.78%	0.77%	0.75%
2. Utility O&M ($M)										
2.1 Customer Care	92	94	95	97	99	101	102	104	106	108
2.2 RCAM	52	53	54	55	56	57	58	59	60	61
2.3 DSM	66	68	68	69	70	71	73	74	75	76
2.4 Pension	22	23	25	25	26	26	27	27	28	28
2.5 Departmental	209	213	217	221	225	229	233	237	241	245
2.6 Total Utility O&M	441	451	460	468	476	484	492	501	509	518
3. Capital Additions, ICM threshold, Rate base and Depreciation										
3.1 Capital expenditures ($M)	633	724	575	635	577	586	610	820	594	601
3.2 Rate Base ($M)	7,025	7,422	7,776	8,060	8,330	8,576	8,842	9,238	9,623	9,869
3.3 Depreciation (weighted Average)	3.2%	3.3%	3.3%	3.3%	3.2%	3.2%	3.1%	3.0%	3.0%	2.9%
3.4 ICM threshold ($M)	503	507	506	512	515	518	521	524	527	531
3.5 ICM capital ($M)	111	217	70	123	62	68	89	296	67	70
4. Cost of Capital										
4.1 Cost of long term debt	4.4%	4.7%	4.8%	4.8%	4.8%	4.8%	4.8%	4.8%	4.8%	4.8%
4.2 Allowed ROE	9.15%	9.28%	9.37%	9.37%	9.37%	9.37%	9.37%	9.37%	9.37%	9.37%
5 Taxes										
5.1 Income tax rate	26.5%	26.5%	26.5%	26.5%	26.5%	26.5%	26.5%	26.5%	26.5%	26.5%
5.2 Municipal taxes ($M)	51	53	56	59	61	64	66	69	72	75

Table 2

(ii) EGD Revenues and Earnings - Stand Alone

$ Millions	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Cost of Capital										
Rate base	7,025	7,422	7,776	8,060	8,330	8,576	8,842	9,238	9,623	9,869
Required rate of return	6.19%	6.27%	6.31%	6.31%	6.30%	6.31%	6.33%	6.34%	6.35%	6.36%
	435	**465**	**490**	**509**	**525**	**541**	**559**	**586**	**611**	**628**
Cost of Service										
Gas costs	-	-	-	-	-	-	-	-	-	-
Operation and maintenance	441	451	460	468	476	484	492	501	509	518
Depreciation and amortization	328	349	367	382	392	401	411	419	428	439
Fixed financing costs	3	3	3	3	3	3	3	3	3	3
Municipal and other taxes	51	53	56	59	61	64	66	69	72	75
	822	**856**	**886**	**911**	**932**	**952**	**973**	**992**	**1,012**	**1,035**
Income Taxes	**43**	**36**	**52**	**53**	**60**	**54**	**60**	**51**	**70**	**75**
Total Revenues	**1,300**	**1,357**	**1,428**	**1,473**	**1,516**	**1,546**	**1,592**	**1,629**	**1,693**	**1,738**
Utility Earnings	**231**	**248**	**262**	**272**	**281**	**289**	**298**	**312**	**325**	**333**

Table 3

(iii) EGD Rate Base

$ Millions	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**
Property, Plant, and Equipment										
Cost or redetermined value	10,108	10,646	11,220	11,743	12,258	12,747	13,249	13,830	14,410	14,925
Accumulated depreciation	(3,443)	(3,582)	(3,802)	(4,042)	(4,287)	(4,529)	(4,766)	(4,950)	(5,146)	(5,415)
Net property, plant, and equipment	6,666	7,064	7,418	7,701	7,971	8,217	8,483	8,880	9,264	9,510
Affiliate shared Asset	(9)	(9)	(9)	(9)	(9)	(9)	(9)	(9)	(9)	(9)
Net PP&E in Rate base	6,657	7,055	7,409	7,692	7,962	8,208	8,474	8,871	9,255	9,501
Allowance for working capital	368	368	368	368	368	368	368	368	368	368
Total Rate base	**7,025**	**7,422**	**7,776**	**8,060**	**8,330**	**8,576**	**8,842**	**9,238**	**9,623**	**9,869**

Table 4

(iv) EGD Capital Structure

$ Millions	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**
Long term debt										
Principal	4,218	4,513	4,689	4,922	5,051	5,204	5,480	5,627	5,852	6,020
Component	60.04%	60.81%	60.30%	61.07%	60.64%	60.69%	61.98%	60.90%	60.81%	61.01%
Cost Rate	4.67%	4.66%	4.68%	4.67%	4.66%	4.67%	4.66%	4.73%	4.74%	4.76%
Return Component	2.80%	2.84%	2.83%	2.85%	2.83%	2.84%	2.89%	2.88%	2.88%	2.90%
Short term debt										
Principal	178	137	187	136	180	184	79	186	207	196
Component	2.54%	1.84%	2.41%	1.69%	2.16%	2.15%	0.89%	2.01%	2.15%	1.98%
Cost Rate	2.10%	2.50%	2.70%	2.70%	2.70%	2.70%	2.70%	2.70%	2.70%	2.70%
Return Component	0.05%	0.05%	0.07%	0.05%	0.06%	0.06%	0.02%	0.05%	0.06%	0.05%
Preference Shares										
Principal	100	100	100	100	100	100	100	100	100	100
Component	1.42%	1.35%	1.29%	1.24%	1.20%	1.17%	1.13%	1.08%	1.04%	1.01%
Cost Rate	2.80%	3.28%	3.44%	3.44%	3.44%	3.44%	3.44%	3.44%	3.44%	3.44%
Return Component	0.04%	0.04%	0.04%	0.04%	0.04%	0.04%	0.04%	0.04%	0.04%	0.03%
Common Equity										
Principal	2,529	2,672	2,799	2,901	2,999	3,087	3,183	3,326	3,464	3,553
Component	36.00%	36.00%	36.00%	36.00%	36.00%	36.00%	36.00%	36.00%	36.00%	36.00%
Cost Rate	9.15%	9.28%	9.37%	9.37%	9.37%	9.37%	9.37%	9.37%	9.37%	9.37%
Return Component	3.29%	3.34%	3.37%	3.37%	3.37%	3.37%	3.37%	3.37%	3.37%	3.37%
Required Rate of Return	**6.19%**	**6.27%**	**6.31%**	**6.31%**	**6.30%**	**6.31%**	**6.33%**	**6.34%**	**6.35%**	**6.36%**

a. Assumptions for Union Gas (Stand-alone)

Table 5

(i) UG Assumptions	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
1. Distribution Revenues										
1.1 Customer Additions	17,742	17,288	17,290	17,284	17,257	17,201	17,195	17,217	17,296	17,432
1.2 Escalation factor:										
1.2.1 GDPIPI	1.73%	1.73%	1.73%	1.73%	1.73%	1.73%	1.73%	1.73%	1.73%	1.73%
1.2.2 Productivity factor	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
1.2.3 Growth factor	0.93%	0.90%	0.89%	0.88%	0.87%	0.86%	0.85%	0.85%	0.84%	0.84%
2. Utility O&M										
2.1 Customer Care	-	-	-	2	4	6	8	10	12	14
2.2 DSM	63	63	63	63	63	63	63	63	63	63
2.3 Departmental & Others	380	393	400	408	417	425	434	443	452	461
2.4 Total Utility O&M	443	456	463	473	484	494	505	516	527	538
3. Capital Additions, ICM threshold, Rate base and Depreciation										
3.1 Capital expenditures ($M)	587	429	450	438	609	589	426	423	436	436
3.2 Rate Base ($M)	6,417	6,732	6,852	7,003	7,116	7,362	7,549	7,586	7,612	7,638
3.3 Depreciation (weighted Average)	2.9%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%
3.4 ICM threshold ($M)	330	331	334	336	339	341	344	347	350	354
3.5 ICM capital ($M)	211	77	114	96	264	249	76	58	88	31
4. Cost of Capital										
4.1 Cost of long term debt	4.4%	4.7%	4.8%	4.8%	4.8%	4.8%	4.8%	4.8%	4.8%	4.8%
4.2 Allowed ROE	9.15%	9.28%	9.37%	9.37%	9.37%	9.37%	9.37%	9.37%	9.37%	9.37%
5 Taxes										
5.1 Income tax rate	26.5%	26.5%	26.5%	26.5%	26.5%	26.5%	26.5%	26.5%	26.5%	26.5%
5.2 Municipal taxes ($M)	79	81	83	85	87	89	91	93	95	97

Table 6

(ii) UG Revenues and Earnings- Stand Alone

$ Millions	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Cost of Capital										
Rate base	6,417	6,732	6,852	7,003	7,116	7,362	7,549	7,586	7,612	7,638
Required rate of return	5.99%	6.05%	6.16%	6.18%	6.22%	6.23%	6.20%	6.24%	6.24%	6.24%
	384	**408**	**422**	**433**	**443**	**459**	**468**	**473**	**475**	**477**
Cost of Service										
Gas costs	-	-	-	-	-	-	-	-	-	-
Operation and maintenance	443	456	463	473	484	494	505	516	527	538
Depreciation and amortization	298	319	330	340	353	369	382	393	404	415
Fixed financing costs	2	2	2	2	2	2	2	2	2	2
Municipal and other taxes	79	81	83	85	87	89	91	93	95	97
	822	**858**	**878**	**901**	**926**	**954**	**980**	**1,004**	**1,028**	**1,052**
Income Taxes	**24**	**35**	**40**	**43**	**47**	**55**	**63**	**68**	**73**	**85**
Total Revenues	**1,231**	**1,300**	**1,340**	**1,377**	**1,416**	**1,468**	**1,511**	**1,545**	**1,575**	**1,614**
Utility Earnings	**211**	**225**	**231**	**236**	**240**	**248**	**255**	**256**	**257**	**258**

Table 7

(iii) UG Rate Base

$ Millions	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Property, Plant, and Equipment:										
Cost or redetermined value	9,995	10,574	10,953	11,361	11,742	12,265	12,754	13,109	13,466	13,834
Accumulated depreciation	(3,783)	(4,047)	(4,306)	(4,564)	(4,830)	(5,108)	(5,409)	(5,729)	(6,059)	(6,400)
Net property, plant, and equipment	6,212	6,527	6,647	6,798	6,911	7,157	7,344	7,381	7,407	7,433
Affiliate shared Asset	-	-	-	-	-	-	-	-	-	-
Net PP&E in Rate base	6,212	6,527	6,647	6,798	6,911	7,157	7,344	7,381	7,407	7,433
Allowance for working capital	205	205	205	205	205	205	205	205	205	205
Total Rate base	**6,417**	**6,732**	**6,852**	**7,003**	**7,116**	**7,362**	**7,549**	**7,586**	**7,612**	**7,638**

Table 8

(iv) UG Capital Structure

$ Millions	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Long term debt										
Principal	3,958	4,161	4,314	4,377	4,450	4,607	4,677	4,575	4,592	4,609
Component	61.68%	61.81%	62.96%	62.51%	62.53%	62.58%	61.95%	60.31%	60.33%	60.34%
Cost Rate	4.26%	4.27%	4.36%	4.41%	4.47%	4.49%	4.46%	4.56%	4.57%	4.57%
Return Component	2.63%	2.64%	2.75%	2.76%	2.80%	2.81%	2.76%	2.75%	2.75%	2.76%
Short term debt										
Principal	45	44	(33)	1	0	1	51	176	176	175
Component	0.70%	0.65%	-0.48%	0.01%	0.01%	0.01%	0.67%	2.32%	2.31%	2.30%
Cost Rate	2.10%	2.50%	2.70%	2.70%	2.70%	2.70%	2.70%	2.70%	2.70%	2.70%
Return Component	0.01%	0.02%	-0.01%	0.00%	0.00%	0.00%	0.02%	0.06%	0.06%	0.06%
Preference Shares										
Principal	104	104	104	104	104	104	104	104	104	104
Component	1.62%	1.54%	1.52%	1.49%	1.46%	1.41%	1.38%	1.37%	1.37%	1.36%
Cost Rate	3.12%	3.57%	3.72%	3.72%	3.72%	3.72%	3.72%	3.72%	3.72%	3.72%
Return Component	0.05%	0.06%	0.06%	0.06%	0.05%	0.05%	0.05%	0.05%	0.05%	0.05%
Common Equity										
Principal	2,310	2,424	2,467	2,521	2,562	2,650	2,718	2,731	2,740	2,750
Component	36.00%	36.00%	36.00%	36.00%	36.00%	36.00%	36.00%	36.00%	36.00%	36.00%
Cost Rate	9.15%	9.28%	9.37%	9.37%	9.37%	9.37%	9.37%	9.37%	9.37%	9.37%
Return Component	3.29%	3.34%	3.37%	3.37%	3.37%	3.37%	3.37%	3.37%	3.37%	3.37%
Required Rate of Return	**5.99%**	**6.05%**	**6.16%**	**6.18%**	**6.22%**	**6.23%**	**6.20%**	**6.24%**	**6.24%**	**6.24%**

a. Assumptions for Amalco (Enbridge Gas Distribution and Union Gas)

Table 9

(i) Amalco Revenues - Price Cap

$ Millions	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
EGD	1,305	1,353	1,397	1,440	1,482	1,523	1,565	1,619	1,672	1,715
UG	1,225	1,277	1,311	1,348	1,390	1,441	1,489	1,525	1,563	1,599
Amalco Total Revenues	**2,530**	**2,630**	**2,709**	**2,788**	**2,872**	**2,964**	**3,054**	**3,144**	**3,234**	**3,314**

(ii) Amalco Utility Earnings with synergies

$ Millions	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Utility Earnings - Price cap										
EGD	235	245	240	247	256	272	278	304	309	316
UG	207	208	210	215	220	228	238	242	247	247
Utility Earnings before synergies	**442**	**453**	**450**	**463**	**477**	**500**	**517**	**546**	**556**	**563**
After-tax synergies from attachment 12 in the evidence EB-2017-0306:										
Earnings drag - To fund synergy capital	1	3	3	(2)	(10)	(16)	(17)	(17)	(16)	(16)
O&M savings with synergies - after tax	2	28	46	51	60	62	62	62	62	62
Net synergies - after tax	**3**	**31**	**49**	**49**	**49**	**47**	**45**	**46**	**46**	**46**
Utility Earnings with synergies	**445**	**483**	**500**	**512**	**526**	**547**	**562**	**591**	**603**	**609**
Earnings sharing	-	-	-	-	-	-	-	-	-	-
Amalco Utility Earnings after synergies	**445**	**483**	**500**	**512**	**526**	**547**	**562**	**591**	**603**	**609**

Table 10

(ii) EGD Revenues and Earnings - Price Cap

$ Millions	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Revenue Requirement										
2018 Revenue Requirement	1,233									
Less Rate smoothing	(5)									
DSM	(68)									
Flow-through adjustments	-									
2018 Revenue Requirement for escalation	1,160									
Escalation factor										
GDPIPI LRP Forecast	1.73%	1.73%	1.73%	1.73%	1.73%	1.73%	1.73%	1.73%	1.73%	1.73%
Growth factor	0.93%	0.92%	0.84%	0.87%	0.84%	0.82%	0.80%	0.78%	0.77%	0.75%
Revenue Requirement with escalation	**1,191**	**1,223**	**1,254**	**1,287**	**1,320**	**1,353**	**1,388**	**1,422**	**1,458**	**1,494**
Flow through										
DSM	66	68	68	69	70	71	73	74	75	76
Flow-through adjustments	-	-	-	-	-	-	-	-	-	-
ICM recovery	5	19	32	40	48	54	60	77	92	97
Total flow-through	71	87	100	109	118	125	133	150	167	174
Other Revenues	43	43	44	44	44	45	45	46	46	47
Total Revenues	**1,305**	**1,353**	**1,397**	**1,440**	**1,482**	**1,523**	**1,565**	**1,619**	**1,672**	**1,715**
Utility Earnings	**235**	**245**	**240**	**247**	**256**	**272**	**278**	**304**	**309**	**316**

Table 11

(iii) UG Revenues and Earnings - Price Cap

$ Millions	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Revenue Requirement										
2018 Revenue Requirement	1,161									
Less Rate smoothing	-									
DSM	(63)									
Flow-through adjustments	(116)									
2018 Revenue Requirement for escalation	982									
Escalation factor										
GDPIPI LRP Forecast	1.73%	1.73%	1.73%	1.73%	1.73%	1.73%	1.73%	1.73%	1.73%	1.73%
Growth factor	0.93%	0.90%	0.89%	0.88%	0.87%	0.86%	0.85%	0.85%	0.84%	0.84%
Revenue Requirement with escalation	**1,008**	**1,035**	**1,062**	**1,089**	**1,118**	**1,147**	**1,176**	**1,207**	**1,238**	**1,270**
Flow through										
DSM	63	63	63	63	63	63	63	63	63	63
Flow-through adjustments & others	125	135	135	135	137	138	139	139	139	138
Accumulated deferred tax drawdown	17	17	17	17	17	17	17	17	17	17
ICM recovery	12	27	35	44	55	76	94	100	106	111
Total flow-through	217	242	250	259	272	294	313	319	325	329
Total Revenues	**1,225**	**1,277**	**1,311**	**1,348**	**1,390**	**1,441**	**1,489**	**1,525**	**1,563**	**1,599**
Utility Earnings	**207**	**208**	**210**	**215**	**220**	**228**	**238**	**242**	**247**	**247**

a. Assumptions for Incremental Capital Module (Enbridge Gas Distribution)

Table 12

(i) EGD ICM threshold calculation

ICM THRESHOLD CALCULATION FORMULA

ICM Threshold Value = 1 +[(rb/d) * (g + PCI * (1 + g))] * ((1 + g) * (1 + PCI))^n-1 + 10%

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Threshold Factor	10%									
Base year	**2018**									
Ratebase	6,246									
Rebasing Depreciation Expense	305									
Growth rate	0.93%	0.92%	0.84%	0.87%	0.84%	0.82%	0.80%	0.78%	0.77%	0.75%
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	1	2	3	4	5	6	7	8	9	10
ICM Multiplier	1.65	1.66	1.66	1.68	1.69	1.69	1.71	1.72	1.73	1.74
ICM Threshold value	503	507	506	512	515	518	521	524	527	531

Table 13

(ii) EGD Growth factor

$ Millions	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
2018 Distribution revenues	1,228									
Incremental Revenues from growth	11	11	10	11	11	11	10	10	10	10
Distribution revenues @ 2018 frozen rates	1,239	1,251	1,261	1,272	1,283	1,293	1,304	1,314	1,324	1,334
Growth factor (%)	**0.93%**	**0.92%**	**0.84%**	**0.87%**	**0.84%**	**0.82%**	**0.80%**	**0.78%**	**0.77%**	**0.75%**

Table 14

(iii) EGD ICM Revenue Requirement

$ Millions	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
ICM capital	111	217	70	123	62	68	89	296	67	70
Cost of Capital										
Rate base	55	216	351	437	516	566	628	800	956	996
Required rate of return	6.09%	6.28%	6.37%	6.38%	6.40%	6.40%	6.41%	6.42%	6.42%	6.42%
	3	14	22	28	33	36	40	51	61	64
Cost of Service										
Operation and maintenance	-	-	-	-	-	-	-	-	-	-
Depreciation and amortization	1	6	9	12	14	16	18	23	28	30
	1	6	9	12	14	16	18	23	28	30
Income Taxes	(0)	(0)	0	0	1	1	2	2	3	4
Total Revenue Requirement	**5**	**19**	**32**	**40**	**48**	**54**	**60**	**77**	**92**	**97**

a. <u>Assumptions for Incremental Capital Module (Union Gas)</u>

Table 15

(i) UG 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	0.93%	0.90%	0.89%	0.88%	0.87%	0.86%	0.85%	0.85%	0.84%	0.84%
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	1.68	1.69	1.70	1.72	1.73	1.74	1.76	1.77	1.79	1.81
ICM Threshold value	330	331	334	336	339	341	344	347	350	354

Table 16

(ii) UG Growth factor

$ Millions	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**
2018 Distribution revenues	948									
Incremental Revenues from growth	9	9	9	9	9	9	9	9	9	9
Distribution revenues @ 2018 frozen rates	957	965	974	982	991	999	1,008	1,016	1,025	1,034
Growth factor (%)	**0.93%**	**0.90%**	**0.89%**	**0.88%**	**0.87%**	**0.86%**	**0.85%**	**0.85%**	**0.84%**	**0.84%**

Table 17

(iii) UG ICM Revenue Requirement

$ Millions	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**
ICM capital	211	77	114	96	264	249	76	58	88	31
Cost of Capital										
Rate base	151	338	415	509	631	865	1,040	1,071	1,101	1,127
Required rate of return	6.09%	6.25%	6.31%	6.34%	6.36%	6.39%	6.40%	6.41%	6.42%	6.43%
	9	21	26	32	40	55	67	69	71	72
Cost of Service										
Operation and maintenance	-	-	-	-	-	-	-	-	-	-
Depreciation and amortization	6	11	14	17	22	30	35	37	39	41
	6	11	14	17	22	30	35	37	39	41
Income Taxes	(2)	(2)	(2)	(2)	(4)	(6)	(5)	(3)	(1)	1
Total Revenue Requirement	**13**	**30**	**38**	**47**	**58**	**80**	**97**	**103**	**109**	**115**
Incremental revenues from community expansions	(2)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)
Revenue Requirement (Net)	**12**	**27**	**35**	**44**	**55**	**76**	**94**	**100**	**106**	**111**

b) 2019 costs were forecasted at a high level on an aggregate basis and were rebased as follows:

O&M costs
The departmental O&M and Customer Care costs were assumed to increase by 2% for EGD and at inflation rate for Union Gas over the 2018 budget. Pension costs are based on estimate from Mercer. DSM costs are the board approved numbers. EGD RCAM are based on historical and are assumed to be 85% of budgeted CAM.

Capital costs
The capital costs are the forecasts from the Asset Management Plan of each Utility.

Cost of capital
The cost of capital parameters reflects the forecast for Enbridge treasury. Long term debt assumes new debt issuance to finance rate base growth and refinancing of debt coming to maturity.

c) There is a certain amount of assumed productivity embedded in the O&M cost assumptions. Both utilities incur incremental O&M costs to attach customers each year. It has been modelled that these cost increases will be offset by productivity gains. The increased O&M costs modelled therefore only assumes an inflationary increase.

The productivity factor applicable to the Price Cap of zero with a stretch factor of zero was used for the two Utilities.

The productivity factor was proposed based on the total productivity analysis and associated recommendations prepared by Jeff Makholm provided at EB-2017-0307, Exhibit B, Tab 2. EGD and Union's productivity growth is in line with the economy as whole and the economy-wide inflation is appropriate for setting rates during the deferred rebasing period

d) Throughout the ten year period, the Revenue Requirement for the amalgamated company (Amalco) is lower than the Revenue Requirement total of the two separate companies. We do not understand the question.

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

include any amount for deferred taxes?
MR. TETREAULT: If memory serves, it is there as a credit to rate base. It serves as a reduction to cost to service, some of which is in rate base.
The history or the genesis of why that happened in the late '90s, I'm not sure.
MR. SHEPHERD: Okay, but that's maximum 17 million a year, because that's what the drawdown is?
MR. TETREAULT: I think that's fair.
MR. SHEPHERD: Okay. I have a document here that's entitled "Ten-year revenue and expense forecast, Enbridge and Union." This is actually all your numbers, except for calculations we've done to them. And we went back and forth on this over the weekend, and I think we have agreed that these numbers are now accurate.
So first, can you confirm that these numbers are now accurate? And second, can we get a number for it? I asked Andrew at the break to tell me that they were accurate.
MR. REINISCH: So yes, based on the sources below, we've confirmed that these numbers are accurately captured and the calculations are accurate within Excel.
MR. MILLAR: Would you like that marked as an exhibit?
MR. SHEPHERD: Please.
MR. MILLAR: KT3.3.
EXHIBIT NO. KT3.3: DOCUMENT ENTITLED "TEN YEAR REVENUE AND EXPENSE FORECAST, ENBRIDGE AND UNION"
MR. SHEPHERD: I just have one question. So for 2018, in your board material, you forecast a total ROE of

between 2013 and 2019.

It would be same slightly simpler from EGD's Perspective, based on their go-forward 2018 Board-approved financials to the 2018 -- sorry, the 2019 starting point. But again, there are a significant number of moving pieces involved.

MR. SHEPHERD: I understand it's complicated. But you went to your board of directors and you said, Well, If we file for custom IR, will get $2.53 billion in revenues. And if we to it this other way that we're proposing, we will get 2.530. So you didn't just make those numbers up, right?

MR. REINISCH: No.

MR. SHEPHERD: So --

MR. REINISCH: We took a view of what the costs were for both utilities in 2019, should we apply for a custom IR. We did a build-up of those costs and that is the number that we provided in the custom IR, so line 6 on this chart, in this table.

MR. SHEPHERD: All right. Sorry, line 6 is the custom IR; that's right. What you've called to your board status quo.

So then I see in 2020 what you are saying is that under custom IR, you'd ask for roughly a 5 percent increase, but you are only going to get a 4 percent increase under your current proposal.

Once more, I'm not sure I understand why that would be. Is there some rationale?

And before you answer, because it is going to look like a trap otherwise which I am not intending, by 2023 you've got it the other way around. You're getting bigger increases under your current proposal than you are under -- under custom IR and so this -- these numbers don't look like they make sense and I'm trying to understand. Can you help me?

MR. REINISCH: So under a price cap, which is the proposal which would be your line 3 on this chart, costs are disconnected from revenues.

So, in line 3, revenues are increased, inflated by 1.73 percent a year and adjusted for any ICM-eligible capital that we feel is prudent, and would be approved by the Board.

And that's how you end up with line 3. With respect to line 6, that is more of a cost-based look as the revenue requirement required to recover our costs.

With respect to line 3, there are some unidentified operating efficiencies that would go into the ROE, but because those are savings that have nothing to do with the revenue, those would not appear in line 3.

MR. SHEPHERD: All right. Okay, I'm going to leave that for now. We'll obviously come back to it in the hearing.

I want to go to the impacts of your ICM proposal, and I want to start by asking about your asset management plans which -- you've talked about them. I mean, obviously they're in the evidence, all 700-pages of them. But I'm looking at page 8 of attachment 1 of FRPO 1.

By the way, before I go to that, you didn't actually model the custom IR option in a detailed way when you went to your board of directors, right? Did you sit down and say, look, let's try to imagine what would a custom IR application for each utility look like, and what would the results be? You didn't actually do that, right?

MR. REINISCH: So that information was provided in interrogatory response to FRPO 11A.

MR. SHEPHERD: Where you've done a high-level calculation, I get that.

That's different than thinking through what your actual costs are going to be. That's a different exercise, right?

MR. REINISCH: We made a series of assumptions and forecasts, and those are what are included in the model that we have provided in response to FRPO 11.

MR. SHEPHERD: And what I'm asking is the -- in this technical conference, you've said many, many times all your estimates were high-level, and that model looks pretty high-level.

I guess my question is: At any point did you say, let's check out the main alternative custom IR and see whether it really is better. Let's do a deep dive of some sort. You didn't do that.

MR. KITCHEN: What we did, Mr. Shepherd, is that we went through a series of, I would call them assumptions to produce a forecast. Did we go in and actually produce what would be necessary if we were planning to bring forward a custom IR for both utilities? No, but what you have in FRPO 11 are the assumptions that we made in order to make the assessment for the Board that we would pursue the amalgamation.

MR. SHEPHERD: If you were going to do a custom IR, and Enbridge has actually done one, and you've obvious looked at the (inaudible) as well, you would do a bottom-up budget, like, a full bottom-up budget for the period in question; right?

MR. KITCHEN: That's correct.

MR. SHEPHERD: And one of the things you'd do is you look for savings, you look for ways that you can drive down your cost, because you know it's going to be challenged in a hearing; right?

MR. CULBERT: Well, as I mentioned, I'm not sure what day it was, Mr. Shepherd, Day 1 or 2, review of the custom IR approach that is now required by the Board can't be handled in the exact fashion that EGD handled its first custom IR, it has to be a projection of costs to your point from a bottom-up perspective in terms of what the entities estimate their costs to be. There is to be no inclusion of productivity offsets within those forecasts, is my read of the custom IR approach, and then you need to develop a custom index coming out of that, and again, as I mentioned the other day, I'm still not sure I know exactly what that is, but you need to develop that through the assistance of consultants to develop TFP study, benchmarking study.

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

see.

This sort of sets out an easy way, at least in my mind, to see what it is that the company is proposing as justification for it. And what I propose to do first is just go through some of the items and confirm some things.

So line 1, I've called it the stand-alone cost and rate proposal, on the premise that this is certainly -- and Exhibit B, tab 1, page 20 is described as what the company says would be the stand-alone costs for both utilities in combination if there was no merger, correct?

MR. REINISCH: That is correct.

MR. BUONAGURO: And then I call it the rate proposal, because you tell us what the stand-alone rate proposal, you're saying this is what we would charge customers if there was no merger, correct?

MR. REINISCH: That is the correct. That is the assumption that we would apply to stand-alone cost-of-service custom IR proposals --

MR. BUONAGURO: Thank you. And I'm not sure you have to turn it up, but LPMA 5, so Exhibit C.LPMA.5 asked about the stand-alone costs, and it was described in an interrogatory answer that those costs were based on the custom IR, correct?

MR. REINISCH: That's correct.

MR. BUONAGURO: And specifically when you look at Part A, the response, it says here:

> "It would be similar to EGD's current custom IR plan as approved by the Board in EB-2012-0459."

Correct?

MR. REINISCH: It would be similar, yes.

MR. BUONAGURO: And when you say "similar" do you mean similar in terms of what Enbridge applied for in that application?

MR. CULBERT: It means it would be a custom IR application that is similar in nature. Of course, we would be adhering to all of the current custom IR requirements that the Board has on file, so it would have a rebasing year to begin, and then all aspects of what's required for a custom IR application.

MR. BUONAGURO: All right. And I asked the question because in contrast to what the Board decided in that case, which was very different than -- in my mind, anyway, different than what was applied for in certain aspects.

MR. CULBERT: Yeah, I agree, the Board in that hearing identified some shortcomings relative to what their expectations of custom IR were. Of course, that was just evolving at the time, and the Board noted that in its decision that custom IR was just evolving, and they have since, I'll say, better quantified what custom IR means to them and to other parties applying, so, yes, we would be following the Board's custom IR requirements as identified --

MR. BUONAGURO: Thank you.

MR. CULBERT: -- currently.

MR. BUONAGURO: And just to round it off, because we are talking about ten years and two utilities during deferral period, we're talking about line 1 representing a forecast of what four separate custom IR applications would produce, correct?

MR. REINISCH: That is correct. Both utilities through the ten-year period would have two custom IR periods each.

MR. BUONAGURO: And at the risk of stating the obvious, there's -- there are no such applications before the Board in any form, correct?

MR. REINISCH: That is correct. We have not applied for a custom IR.

MR. BUONAGURO: If you said yes I would have been in big trouble.

So line 2, I call it the Amalco rate proposal, and I expect you do too, and that's also in that same exhibit, Exhibit B, tab 1, page 20, and that's what you are saying rates will look like for the two utilities in total, in terms of how much those rates will cost ratepayers during the deferral period if the merger's approved and the proposal goes through as applied for, right?

MR. KITCHEN: That's -- the 411 million identified in line 3 is the result of a no-harm test, yes, and it's basically stand-alone versus the price cap mechanism that we've proposed.

MR. BUONAGURO: All right. So I was referring to line 2. You jumped ahead.

MR. KITCHEN: Okay.

MR. BUONAGURO: Line 2 is the actual proposal, and

COLDER WINTER, WARMER WINTER.

MS. GIRVAN: Sorry, I'm just reviewing my notes and seeing what Mr. Shepherd has covered off.

So can you explain to me since you've made such significant reductions in staff why this couldn't be a base rate reduction?

MR. CULBERT: You are referring to the EGD results, obviously, Ms. Girvan? Well, as we pointed out earlier, the discussion with Mr. Shepherd alerted parties to the fact that we actually have capital spending amounts during the period which are not going into rates either, so our view is the Board's policy is they don't -- you don't do a cost-of-service rebasing for a MAADs application; you use a price cap methodology for rates going forward, so to perform a full cost-of-service rebasing for the purpose of MAADs, we don't view it as being a relevant element of the application.

In speaking with Mr. Shepherd earlier, the rate base value difference I've come to the answer is actually $457 million difference between Board-approved for '18 and what the estimate is, so that amounts to about a $35 million, I'll say, deficiency that we are not recovering the rates.

So you wouldn't just put one element of a rebasing through for O&M. You'd have to look at the whole cost-of-service rebasing, which involves everything, which we don't believe is part of the Board's model for a MAADs application.

ENBRIDGE GAS DISTRIBUTION INC. AND UNION GAS LIMITED

Undertaking of Mr. Culbert
To Mr. Shepherd

REF: Tr.1, p.77

To provide the final figures for 2018 rate base in the EB-2012-0459 case.

Included as Attachment 1 to this undertaking is Exhibit B1, Tab 1, Schedule 2 from EGD's 2018 Rate Adjustment proceeding, EB-2017-0086. The exhibit shows EGD's 2018 updated forecast 2018 rate base of $6,246.1 million, approved for establishing 2018 rates as part of that proceeding, as compared to the approved 2018 placeholder rate base of $6,152.6 million, from EGD's 2014 – 2018 Custom Incentive Regulation application EB-2012-0459.

Within the EB-2017-0086 updated forecast rate base value, the 2018 forecast cost or redetermined value of property, plant, and equipment was updated to reflect an allocation of base pressure gas to Unregulated Storage operations, as was determined in the EB-2015-0114 Settlement Agreement. The 2018 forecast gas in storage value was updated to reflect changes resulting from the 2018 volumes re-forecast and re-determined 2018 gas supply plan. The updated gas in storage value also reflected July 1, 2017 QRAM prices, whereas the 2018 placeholder gas in storage value reflected April 1, 2013 QRAM prices. Finally. the 2018 forecast working cash allowance was also updated to reflect impacts resulting from the 2018 volumes re-forecast, re-determined 2018 gas supply plan, gas purchase and storage and transportation costs valued at July 1, 2017 QRAM prices versus April 1, 2013 QRAM prices, and 2018 operation and maintenance cost updates.

UTILITY RATE BASE
2018 UPDATED FORECAST

Line No.		Col. 1 EB-2012-0459 Excl. CIS 2018 Utility Rate Base Placeholder ($Millions)	Col. 2 EB-2012-0459 CIS 2018 Utility Rate Base Placeholder ($Millions)	Col. 3 EB-2012-0459 2018 Total Rate Base Placeholder ($Millions)	Col. 4 2018 CIR Updates Excl. CIS ($Millions)	Col. 5 2018 CIR Updates for CIS ($Millions)	Col. 6 2018 Updated Utility Rate Base Excl. CIS ($Millions)	Col. 7 2018 Utility CIS Rate Base ($Millions)	Col. 8 2018 Total Updated Forecast Utility Rate Base ($Millions)
	Property, Plant, and Equipment								
1.	Cost or redetermined value	9,147.8	127.1	9,274.9	(5.6)	-	9,142.2	127.1	9,269.3
2.	Accumulated depreciation	(3,249.3)	(120.1)	(3,369.4)	-	-	(3,249.3)	(120.1)	(3,369.4)
3.	Net property, plant, and equipment	5,898.5	7.0	5,905.5	(5.6)	-	5,892.9	7.0	5,899.9
	Allowance for Working Capital								
4.	Accounts receivable rebillable projects	1.4	-	1.4	-	-	1.4	-	1.4
5.	Materials and supplies	34.6	-	34.6	-	-	34.6	-	34.6
6.	Mortgages receivable	-	-	-	-	-	-	-	-
7.	Customer security deposits	(64.6)	-	(64.6)	-	-	(64.6)	-	(64.6)
8.	Prepaid expenses	1.0	-	1.0	-	-	1.0	-	1.0
9.	Gas in storage	276.3	-	276.3	94.6	-	370.9	-	370.9
10.	Working cash allowance	(1.6)	-	(1.6)	4.5	-	2.9	-	2.9
11.	Total Working Capital	247.1	-	247.1	99.1	-	346.2	-	346.2
12.	Utility Rate Base	6,145.6	7.0	6,152.6	93.5	-	6,239.1	7.0	6,246.1

Witness: R. Small

ENBRIDGE GAS DISTRIBUTION INC. AND UNION GAS LIMITED

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

Rate Setting Issues List – Issue No. 1

Reference: *Ibid, p13*

Question:

(a) In calculating the ICM materiality threshold value, please explain why it is appropriate for Union to use a value for rate base from six years ago (2013), given the very rapid growth in Union's gas utility rate base since that time.

(b) The evidence states variously that Amalco "may" or "will" apply for rate adjustments using the ICM during any deferred rebasing period. Please confirm that the correct version is that Amalco will apply for ICMs. Will ICMs be used, or could they be used, to fund the implementation costs listed in Exhibit B, Tab 1, Attachment 12 in EB-2017-0306. Please discuss fully.

(c) Please provide a rate base continuity schedule for Union from 2012 to 2018, inclusive. Please show the relationship of the 2018 rate bases for Union and EGD to the 2019 pro forma rate base shown on Attachment 11 of EB-2017-0306.

(d) Please explain why the Board should not employ the method traditionally used by the Board to calculate the cost of capital for the IRM period as at the time of this application (debt and equity) and not change it simply because Amalco wishes to increase the ICM (deferred rebasing period) from five to ten years. Why should changes to the cost of capital not be a risk of doing business given the Amalco's proposed claim to 100% of the savings over a ten year period? (BOMA assumes the 300 basis point threshold for earnings sharing in years six to ten is unlikely to come into play because of its very large size).

(e) Please confirm that if the Board were to authorize a five-year custom IR for Amalco, Amalco would not be eligible for the ACM/ICM, but would be limited to the capital expenditures forecasted over the plan period.

(f) Please provide the actual ROEs achieved by each of EGD and Union in the years 2012 through 2017, inclusive. Please indicate whether these were actuals, or were "normalized" in any way.

Response

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

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

c) Please see Table 1 below.

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

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

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

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

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

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

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

Impact of Opening Rate Base Amounts

EGD Total Excess Rate Base

Amount	*2019*	*2020*	*2021*	*2022*	*2023*	*2024*	*2025*	*2026*	*2027*	*2028*	*Total*
457.0	38.6	38.2	37.9	37.5	37.1	36.7	36.3	36.0	35.6	35.2	369.1

GTA Reinforcement Overrun

Amount	*2019*	*2020*	*2021*	*2022*	*2023*	*2024*	*2025*	*2026*	*2027*	*2028*	*Total*
182.3	15.4	15.3	15.1	15.0	14.8	14.7	14.5	14.4	14.2	14.1	147.3

Sudbury Lost Passthrough

Amount	*2019*	*2020*	*2021*	*2022*	*2023*	*2024*	*2025*	*2026*	*2027*	*2028*	*Total*
70.0	7.0	7.0	6.9	6.8	6.8	6.7	6.6	6.5	6.4	6.3	67.0

undertaken. EGD has had a multitude of other projects undertaken, so the Board would have to go through an extensive review of what projects would need to be reviewed.

I don't see the rationale behind it, necessarily. A cost-of-service rebasing at 2029 would be sufficient for --

MR. GARNER: I was only talking about the material ones. I understand Union has some, too, that are within -- there are always variances. I was suggesting that there were material variances. Would that be an issue?

MR. KITCHEN: I think, Mr. Garner, if the Board were to determine that that was something that was necessary, obviously we would be complying. But I think what Mr. Culbert is saying and what I'd be saying is that we don't think it's necessary until we rebase.

MR. GARNER: Fair enough.

Now, I want to go to tab 4, and again, Mr. Culbert, this is probably just my confusion. I think I know the answer, but maybe you can help me. And there was a long discussion about head counts and FTEs, and that's not where I'm going.

You have -- this is about the savings, the annual customer savings, that are shown in here and their gross costs, et cetera. Again, are those savings embedded in the current rate? Are they outside of where the current rate is? So all of those savings in FTEs or head counts -- again, I'm not standing on the language -- are they embedded in the current rate that's going forward or...

MR. CULBERT: No. Again, those would be items that, if we were doing a full cost-of-service rebasing, would be added into the numbers, or are resident in the numbers in the stand-alone calculations. So they are not amounts that are in rates, just as the capital overages, capital spend amounts versus forecast are not in rates. So no, they're not in rates.

MR. GARNER: Okay. So if I look as this chart, I get this understanding -- and you can correct me if I'm wrong. There has been a significant reduction inside of Enbridge over the past three to four years, probably within the three-year range, in -- I'm not sure to use FTEs or head count, but I think you understand what I mean. There has been a significant change within the company, is that correct?

MR. CULBERT: That's correct.

MR. GARNER: Thank you. This one I don't have a tab for, and this actually came up at the technical conference, Mr. Kitchen, and I don't know if it was on the record and I don't see anything in the undertakings, so perhaps you'll just help me with this.

We had a discussion about putting together a table that would show the rates of the two various utilities, so that there would be an easy way for the Board in understanding what's happening here, if they could understand the difference between similar customers in both utilities, what they would face -- not so much in rate impacts, which has been discussed, but actually in rates

ENBRIDGE GAS DISTRIBUTION INC. AND UNION GAS LIMITED

Undertaking of Mr. Culbert
To Mr. Brett

REF: Tr.3 p.174.

To provide the actual number for the overrun on the GTA project.

Response:

The actual capital cost incurred in relation to the GTA project, excluding the Buttonville Station, is $868.8 million as compared to the Board-approved budget of $686.5 million, resulting in an overage of $182.3 million.

ENBRIDGE GAS DISTRIBUTION INC. AND UNION GAS LIMITED

Undertaking of Mr. Culbert
To Mr. Brett

REF: Tr.3 p.175.

To show what the change in revenue requirement would be in the stand-alone scenario.

Response:

The table below shows EGD's revenue requirement standalone excluding the impact of GTA capital cost overrun.

EGD $ Millions	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Revenue Requirement standalone with GTA overrun	1,300	1,357	1,428	1,473	1,516	1,546	1,592	1,629	1,693	1,738
Revenue requirement impact of GTA overrun	15	15	15	15	15	15	15	14	14	14
Revenue Requirement standalone excluding GTA overrun	1,285	1,342	1,412	1,458	1,501	1,531	1,578	1,615	1,678	1,724

ENBRIDGE GAS DISTRIBUTION INC. AND UNION GAS LIMITED

Answer to Interrogatory from
Energy Probe Research Foundation ("EP")

Rate Setting Application

Reference: Exhibit B, Tab 1 page 13 and Page 14 Table 1

Preamble: The level of capital spend that can be managed under the Price Cap approach is determined by the OEB's calculation of the ICM materiality threshold value.

Question:
a) Please provide the continuity table 2013-2018 for the following parameters in the ICM threshold calculation
   - Rate base
   - Depreciation
   - Gross assets and
   - Net assets

b) With regard to 2019 opening rate base amount(s) and threshold calculation please confirm that the additions to rate base from 2013 approved to 2018 have not been subject to prudence review.

c) How will the overrun on the EGD GTA Project be addressed?

d) Please provide the detailed working papers for the threshold calculation in Table 1.

e) Please discuss how the number of years since rebasing affects the threshold and also why EGD is shown as one-year since cost of service rebasing.

Response

a) Please see the response to LPMA Interrogatory #23 found at Exhibit C.LPMA.23.

b) Capital expenditures for Union's major capital projects are reviewed through the annual non-commodity deferral account proceeding. Capital expenditures for EGD will have been implicitly subject to prudence reviews within the annual actual earnings and ESM applications and reviews through 2018.

c) Any GTA cost overages have not been included in any rate base calculations to date which underpin EGD's ongoing rates and therefore will not be resident in any Price Cap derived rates during the 10 year deferred rebasing period.

d)

EGD

- The threshold calculation in table 1 for EGD can be found in table 12 of the response to FRPO Interrogatory #11(a) found at Exhibit C.FRPO.11.
- The 2018 rate base and depreciation are filed as part of EGD's 2018 custom IR update and can be found in EB-2017-0086, Exhibit B1, Tab 1, Schedule 1 and Exhibit F1, Tab 2, Schedule 1 respectively.
- The growth factor calculation is shown in table 13 of the response to FRPO Interrogatory#11(a) found at Exhibit C.FRPO.11.
- The GDP-IPI factor calculation is described at EB-2017-0306, Exhibit B, Tab 1, page 22, line 9 and 10.

Union Gas:

- The threshold calculation in table 1 for Union Gas can be found in table 15 of the response to FRPO Interrogatory #11(a) found at Exhibit C.FRPO.11.
- The 2013 rate base and depreciation are filed as part of 2013 rebasing application and can be found in EB-2011-0210, Rate Order, Working Papers, Schedule 2 and Schedule 3
- The growth factor calculation is shown in table 16 of the response to FRPO Interrogatory #11(a) found at Exhibit C.FRPO.11.
- The GDP-IPI factor calculation is described at EB-2017-0306, Exhibit B, Tab 1, page 22, line 9 and 10.

e) The OEB's ICM materiality threshold calculation uses Board-approved rate base, depreciation and revenue inputs. These inputs are annualized before they are included in the calculation.

EGD has been under a custom IR, therefore EGD has 2018 Board approved inputs. Union has been operating under a price cap since 2013, therefore the last Board approved inputs for Union are 2013.

Even though each distributor is using a different number of years since rebasing, the inputs are annualized so there is no material impact on the calculation.

right? Do I have that correct?

MR. CULBERT: And the stand-alone custom IR numbers that you see in the evidence today in fact assumed that the GTA total spend would be in rate base for those scenarios, yes.

MR. LADANYI: For scenarios. Now, as far as your plant accounting books are concerned, have you put into your plant accounts the budgeted amount, or the actual amount? Are you perhaps keeping a variance in some other account? How is this accounted for?

MR. CULBERT: You being an accountant would know, Mr. Ladanyi. The actual amounts of the projects are in fact in our books.

MR. LADANYI: But the question here is the Board will not actually rule on the variance for another ten years, when you are going to bring forward your variance explanations to the Board.

MR. CULBERT: The Board will not rule on it for rate-making purposes?

MR. LADANYI: That's right.

MR. CULBERT: That's correct.

MR. LADANYI: So in ten year's time, Enbridge will present reasons why this project went over budget.

MR. CULBERT: I think we've already provided some evidence in one of our ESMs, earning share mechanisms, as to the reasons for the GTA overage were. In fact, probably in the stakeholder days in the past number of years as well.

MR. KITCHEN: Yes.
MR. MONDROW: So some indication of -- some confirmation that those are in fact bookends in the response would be helpful. Otherwise, I'm not sure that it is getting full information.
MR. KITCHEN: We will try to give some indication of that.
MR. MONDROW: That would be helpful. Thank you very much.
MR. RICHLER: J1.4.
UNDERTAKING NO. J1.4: TO PROVIDE RESIDENTIAL BILL IMPACT ESTIMATES FOR 2019 AND 2028
MS. ANDERSON: Now, I think we're moving on to Energy Probe. Mr. Ladanyi?
So I think you were scheduled for 45 minutes and we will probably conclude the day at that point.
MR. LADANYI: Thank you. I hope to be less than 45 Minutes.
MS. ANDERSON: Then we'll see if we can move on to someone new.
CROSS-EXAMINATION BY MR. LADANYI:
MR. LADANYI: Good afternoon, panel. My name is Tom Ladanyi, and I am a consultant to Energy Probe. Maybe we could have somebody pull up the Energy Probe compendium.
And before I go to that, I just have a follow-up question from something that Mr. Shepherd asked this morning.
The GTA project. I understand that the GTA project is

not in rate base right now. Is that right, Mr. Culbert?

MR. CULBERT: It is not in rate base for rate-making purposes, that's correct.

MR. LADANYI: So where is it? Has it been closed to plant accounts?

MR. CULBERT: Yes, it has been closed to plant accounts, and the financial results used for earning sharing purposes, it has been included in those for the past number of years.

MR. LADANYI: So for earning sharing purposes, it is essentially being treated as if it was an asset in rate base. But actually it is not an asset in rate base for rate-setting purposes, is that right?

MR. CULBERT: That's correct.

MR. LADANYI: Now let's to go our compendium. Could you turn to page 2 of the compendium, please?

MR. KITCHEN: Mr. Ladanyi, just before we begin, could someone remind me of the exhibit number for...

MR. LADANYI: For the compendium? Yes, it is K1.4. So this will be for Mr. Kitchen. Mr. Kitchen, were you a witness in this proceeding, EB-2013-0202?

MR. KITCHEN: I don't remember if I was a witness or if I was sitting where Ms. Innis is.

MR. LADANYI: What I mean to say is were you familiar with that case? This is the IRM plan that is ending in 2018, is that right?

MR. KITCHEN: Yes, I was familiar with it and yes, I was a witness.

ONTARIO ENERGY BOARD

FILE NO.: EB-2012-0459

VOLUME: 2

DATE: February 21, 2014

BEFORE:	**Paula Conboy**	**Presiding Member**
	Cynthia Chaplin	**Member and Vice-Chair**
	Emad Elsayed	**Member**

MR. JANIGAN: So the clawing back refers to the resetting rates lower after the IR period to costs, isn't that correct, whenever that term "clawing back" is used?

MR. LISTER: That's correct. So a stream of benefits would ensue an investment, and the utility wouldn't be afforded the opportunity to benefit from the full stream of benefits. So they would be effectively rebased or clawed back at rebasing.

MR. JANIGAN: Okay. So, in effect, in putting in this plan at a materially higher level, you are effectively clawing back some benefits from ratepayers that should accrue to those ratepayers?

[Witness panel confers]

MR. LISTER: So if I understood the question correctly, our position is very much that this mechanism is intended to directly respond to the Board's objective of having utilities generate long-term sustainable efficiencies.

So our view is that if we can show to the Board and to stakeholders that we have indeed accomplished that, that the utility should stand to receive some benefit, yes.

MR. JANIGAN: Okay. So let's assume that your 2014 and '18 plan ends and you rebase in 2009 on your building block basis and apply for a multi-year IRM plan for 2020 using the building block approach that largely ignores the 2009 rebased requirement.

How can there be sustained benefits for ratepayers?

MR. LISTER: Well, our view in our presentation of the

ENBRIDGE GAS DISTRIBUTION INC. AND UNION GAS LIMITED

Undertaking of Mr. Culbert
To Ms. Girvan

REF: Tr.1, p.132

To provide the final results for the gross normalized over-earnings are $47.10 million

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EGD's calculation of actual normalized 2017 utility results, that it expects to file as part of its forthcoming ESM and Deferral Clearance application, reflects a gross sufficiency of $47.1 million to be shared with ratepayers, consistent with the amount reported as part of interrogatories and undertakings in this proceeding.

ENBRIDGE GAS DISTRIBUTION INC. AND UNION GAS LIMITED

Undertaking of Mr. Kitchen
To Ms. Girvan

REF: Tr.1, p.134

To advise directionally which way the earnings sharing mechanism would go, i.e., colder winter, warmer winter.

Please see Attachment 1 for the dollar amount of earnings within Union's deadband, and if weather was warmer or colder.

Union Earning Sharing Results

Year	Directional Weather vs Board-approved	Ratepayer Share of ESM ($Millions)	Earnings within Threshold / Deadband ($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	Colder	34.17	36.25	46.03	13.35%	8.81%	2.00%	90%/10%	EB-2009-0101
2009	Colder	7.40	37.43	14.79	11.24%	8.47%	2.00%	50%/50%	EB-2010-0039
2010	Warmer	3.43	37.26	6.87	10.91%	8.54%	2.00%	50%/50%	EB-2011-0038
2011	Warmer	2.54	35.96	5.08	10.38%	8.10%	2.00%	50%/50%	EB-2012-0087
2012	Warmer	15.13	36.73	24.97	11.03%	7.67%	2.00%	90%/10%	EB-2013-0109
2013	Colder	-	N/A	32.20	10.67%	8.93%	N/A	N/A	No ESM
2014	Colder	7.42	19.48	14.85	10.69%	8.93%	1.00%	50%/50%	EB-2015-0010
2015	Colder	-	19.88	-	9.89%	8.93%	1.00%	N/A	EB-2016-0118
2016	Warmer	-	7.23	-	9.24%	8.93%	1.00%	N/A	EB-2017-0091
2017	Warmer	-	5.90	-	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.

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 8-9

Question:
Please provide a table for each of EGD and Union for the 2013 through 2017 period that shows the approved ROE embedded in rates, the actual ROE, the normalized ROE and the effective X factor included in the respective incentive mechanisms.

Response

Please see Table 1 for Union's information and Table 2 for EGD's information.

Table 1
UNION GAS LIMITED

Line No.	Year	Board-approved ROE	Actual ROE	Weather-normalized ROE	X Factor
		%	%	%	%
1	2013	8.93	10.67 (1)	9.73 (6)	N/A (10)
2	2014	8.93	10.69 (2)	9.23 (7)	0.76 (11)
3	2015	8.93	9.89 (3)	9.46 (8)	1.23 (12)
4	2016	8.93	9.24 (4)	9.78 (9)	1.19 (13)
5	2017	8.93	9.15 (5)	9.54 (5)	1.00 (14)

Notes:
(1) EB-2014-0145, Exhibit A, Tab 2, p. 4
(2) EB-2015-0010, Exhibit A, Tab 2, p. 3
(3) EB-2016-0118, Exhibit A, Tab 2, p. 4.
(4) EB-2017-0091, Exhibit A, Tab 2, p. 3.
(5) Return on equity figures are expected to be included in the Application and Evidence for EB-2018-0105, but are draft at this time and may change.
(6) EB-2015-0010, Exhibit A, Tab 2, p. 1
(7) EB-2015-0010, Exhibit A, Tab 6, slide 7
(8) EB-2016-0118, Exhibit A, Tab 5, slide 7
(9) EB-2017-0091, Exhibit A, Tab 5, slide 5
(10) Not applicable due to Cost of Service
(11) EB-2013-0365, Rate Order, Working Papers, Schedule 1, line 6.
(12) EB-2014-0271, Rate Order, Working Papers, Schedule 1, line 6.
(13) EB-2015-0116, Rate Order, Working Papers, Schedule 1, line 6.
(14) EB-2016-0245, Rate Order, Working Papers, Schedule 1, line 6.

Table 2
ENBRIDGE GAS DISTRIBUTION

Line No.	Year	Board-approved ROE %	Actual ROE %	Weather-normalized ROE %		X-Factor
1	2013	8.93	11.13	10.41	(1)	N/A (6)
2	2014	9.36	12.39	10.46	(2)	N/A (6)
3	2015	9.30	10.41	9.82	(3)	N/A (6)
4	2016	9.19	8.76	9.42	(4)	N/A (6)
5	2017	8.78	9.71	10.27	(5)	N/A (6)

Notes:
(1) EB-2012-0459, Exhibit J1.2
(2) EB-2015-0122, Exhibit B, Tab 5, Schedule 1
(3) EB-2016-0142, Exhibit B, Tab 5, Schedule 1
(4) EB-2017-0102, Exhibit B, Tab 5, Schedule 1
(5) Return on equity figures are expected to be included in the Application and Evidence for EB-2018-0131, but are draft at this time and may change.
(6) Not applicable to EGD as 2013 rates were set under Cost of Service, while 2014 - 2017 were set under Custom IR.

ENBRIDGE GAS DISTRIBUTION INC. AND UNION GAS LIMITED

Answer to Interrogatory from
School Energy Coalition ("SEC")

MAADs Issues List – Issue No. 3-5

Question:
Please provide information, in the same format as found in EB-2012-0459, Exhibit F1/1/1, Table 1, F1/1/2, and F3/1/2, on actual and forecast regulatory income, return and deficiency/sufficiency for Enbridge for the period commencing 2014 and continuing as long as Enbridge has forecast information. Please provide a similar table for Union covering the same period.

Response

Please see Attachments 1 and 2 for Union's information, and Attachment 3 for EGD's information. Please note that the tables found in EB-2012-0459, Exhibit F1, Tab 1, Schedule 2 (Allowed Revenue Deficiency/Sufficiency) do not apply to Union due to the current price cap IR. However, Attachment 1 includes the 2013 Board-approved revenue deficiency/sufficiency.

UNION GAS LIMITED
Calculation of Revenue Deficiency/(Sufficiency)
Year Ended December 31

Line No.	Particulars ($000s)	Board-Approved 2013	Actual 2014	Actual 2015	Actual 2016	Actual 2017	Budget 2018
		(1)	(2)	(3)	(4)	(5)	
1	Operating revenue	1,636,340	1,935,529	1,842,717	1,722,253	2,118,989	2,268,336
2	Cost of service	1,362,212	1,628,716	1,534,839	1,400,491	1,769,137	1,887,056
3	Utility income	274,128	306,813	307,878	321,762	349,852	381,280
4	Requested return	272,639	280,898	292,359	315,580	344,859	368,161
5	Revenue deficiency / (sufficiency) after tax	(1,489)	(25,915)	(15,519)	(6,182)	(4,993)	(13,119)
6	Provision for income taxes on deficiency / (sufficiency)	(509)	(9,344)	(5,595)	(2,229)	(1,800)	(4,730)
7	Distribution revenue deficiency / (sufficiency)	(1,998)	(35,259)	(21,114)	(8,411)	(6,793)	(17,849)
8	Shareholder portion of short-term storage revenue	506	143	449	753	374	282
9	Shareholder portion of optimization activity	1,492	792	774	336	502	701
10	Total revenue deficiency/ (sufficiency)	-	$ (34,324)	$ (19,891)	(7,322)	$ (5,917)	(16,866)

Notes:

(1) EB-2011-0210
(2) EB-2015-0010
(3) EB-2016-0118
(4) EB-2017-0091
(5) Expected to be included in the Application and Evidence for EB-2018-0105, but draft at this time and may change.

UNION GAS LIMITED
Calculation of Revenue Deficiency/(Sufficiency)
Year Ended December 31

Line No.	Particulars ($000s)	Board-Approved 2013 (1)	Actual 2014 (2)	Actual 2015 (3)	Actual 2016 (4)	Actual 2017 (5)	Budget 2018
1	Operating revenue	1,636,340	1,935,529	1,842,717	1,722,253	2,118,989	2,268,336
2	Cost of service	1,362,212	1,628,716	1,534,839	1,400,491	1,769,137	1,887,056
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Notes:

(1) EB-2011-0210
(2) EB-2015-0010
(3) EB-2016-0118
(4) EB-2017-0091
(5) Expected to be included in the Application and Evidence for EB-2018-0105, but draft at this time and may change.

ALLOWED REVENUE AND SUFFICIENCY
EGD 2014 - 2018 APPROVED

Line No.	($Millions)	Col. 1 EB-2012-0459 2014 Approved (Incl. CIS)	Col. 2 EB-2014-00276 2015 Approved (Incl. CIS)	Col. 3 EB-2015-0114 2016 Approved (Incl. CIS)	Col. 4 EB-2016-0215 2017 Approved (Incl. CIS)	Col. 5 EB-2017-0086 2018 Approved (Incl. CIS)
1.	Cost of capital	300.0	323.4	371.9	374.0	387.3
	Cost of service					
2.	Gas costs	1,456.3	1,694.2	1,764.8	1,603.1	1,753.0
3.	O&M (incl. CC/CIS rate smoothing adj.)	422.4	431.3	457.4	462.7	472.3
4.	Depreciation and amortization expense	248.5	261.7	288.9	297.7	305.5
5.	Fixed financing costs	1.9	1.9	1.9	1.9	1.9
6.	Municipal and other taxes	41.2	43.1	45.5	47.9	50.4
7.	Other revenues	(42.8)	(42.8)	(42.8)	(42.8)	(42.8)
8.	Income taxes on earnings	8.9	15.4	23.6	14.4	39.5
9.	Taxes on sufficiency	-	-	-	-	-
10.	Allowed revenue (excl. gas costs)	2,436.4	2,728.2	2,911.2	2,758.9	2,967.1
11.	Revenue at existing rates	2,436.4	2,728.2	2,911.2	2,758.9	2,967.1
12.	Gross revenue (deficiency) / sufficiency	-	-	-	-	-

ALLOWED REVENUE AND SUFFICIENCY
EGD 2014 - 2017 ACTUAL

Line No.	($Millions)	Col. 1 EB-2015-0122 2014 Actual (Incl. CIS)	Col. 2 EB-2014-00276 2015 Actual (Incl. CIS)	Col. 3 EB-2017-0102 2016 Actual (Incl. CIS)	Col. 4 Preliminary 2017 Actual (Incl. CIS)
1.	Cost of capital	310.0	328.4	372.3	389.1
	Cost of service				
2.	Gas costs	1,644.9	1,724.3	1,497.1	1,668.0
3.	O&M (incl. CC/CIS rate smoothing adj.)	408.0	430.7	449.7	431.7
4.	Depreciation and amortization expense	255.9	259.7	292.7	301.3
5.	Fixed financing costs	2.3	3.4	3.2	2.8
6.	Municipal and other taxes	40.5	41.6	43.1	44.6
7.	Other revenues	(43.9)	(50.1)	(43.0)	(42.2)
8.	Income taxes on earnings	6.1	19.4	17.3	1.0
9.	Taxes on sufficiency	(6.7)	(3.4)	(1.8)	(12.5)
10.	Allowed revenue (excl. gas costs)	2,617.1	2,754.0	2,630.6	2,783.8
11.	Revenue at existing rates, net of gas costs	2,642.4	2,766.9	2,637.4	2,830.9
12.	Gross revenue sufficiency	25.3	12.9	6.8	47.1

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

MR. REINISCH: That's correct.

MR. SHEPHERD: But that doesn't mean that the 680 million isn't still savings. You save the 5.2 every year. You don't save it just in one year, do you?

MR. REINISCH: That's correct.

MR. SHEPHERD: Okay. So that should actually be 52 million, right, compared to 9.2 million in costs, right?

MR. REINISCH: On the ten-year deferred rebasing period, yes, that would equate.

MR. SHEPHERD: I wonder if I could move to another area. And you will see this on page 29 of our materials. So we asked you to compare the achieved and allowed ROE for each of the last ten years. That was 2018 to 2017 for each of the two companies. And you did, and you also talked about the sharing that you've had of that over that period of time.

And I just did the math on this, and it appears to me that Enbridge Gas Distribution over-earned by -- in that ten years by a total of 351.5 million.

Will you accept that, subject to check?

MR. CULBERT: I'm assuming you've added up the numbers in these columns?

MR. SHEPHERD: No, no, because that includes the threshold, so you have to actually gross it up to cover the threshold as well, right? I'm talking about comparison between achieved and allowed ROE, right, but you've got a deadband. So you have to gross-up for the deadband. So, for example, in 2008, right, your over-earnings over the

MR. CULBERT: It may be marginally different, but I don't think by too much. Maybe two or three hundred thousand dollars, but I don't have a sense. I could undertake to provide --

MS. GIRVAN: Could you undertake to provide that?

MS. ADAMS: -- what we will be filing. I could do that.

MR. RICHLER: J1.2.

UNDERTAKING NO. J1.2: TO PROVIDE THE FINAL RESULTS FOR THE GROSS NORMALIZED OVER-EARNINGS ARE $47.10 MILLION

MS. GIRVAN: So I note that in 2017, there is this significant over-earnings. Can you explain to me the drivers for that?

MR. CULBERT: I don't have the details with me at this point in time. It will certainly be part of that ESM application.

I can say that you are seeing the effect of -- in the 2016 ESM, from my recollection, we did have a restructuring of sorts which resulted in some FTE reductions.

You didn't see the full effect of that in 2016 because there were severance costs associated with it, and this is just one of the major contributors. So now in 2017 you would be seeing a fuller effect of the savings that come from that restructuring versus what you would have seen in 2016. So that would be one of the major components.

MS. GIRVAN: If you could turn to page 25 of the compendium, and I think this is really what you were

ENBRIDGE GAS DISTRIBUTION INC. AND UNION GAS LIMITED

Answer to Interrogatory from
School Energy Coalition ("SEC")

MAADs Issues List – Issue No. 3-5

Question:
Please provide information, in the same format as found in EB-2012-0459, Exhibit E1/1/1, Table 1, on actual and forecast cost of capital for Enbridge for the period commencing 2014 and continuing as long as Enbridge has forecast information. Please provide a similar table for Union covering the same period.

Response

Please refer to Attachment 1 for the requested cost of capital information for Union, and Attachment 2 for EGD cost of capital information. The Union information is actuals for 2014 to 2017 and 2018 forecast and the EGD information is actuals for 2014-2017 and OEB approved for 2014 to 2018.

Table 1
UNION GAS LIMITED
2014 Actual Cost of Capital Summary

Line No.		Principal (1) ($millions)	Component (1) %	Cost Rate (1) %	Return %	Return (1) ($millions)
1	Long term Debt	2,502.3	62.93%	6.03%	3.80%	151.0
2	Short Term Debt	-60.5	-1.52%	1.19%	-0.02%	-0.7
3	Preferred Shares	103.2	2.59%	2.74%	0.07%	2.8
4	Common Equity	1,431.5	36.00%	8.93%	3.21%	127.8
5	Total	3,976.4	100.00%		7.06%	280.9

Notes:
(1) EB-2015-0010, Exhibit A, Tab 2, Appendix A, Schedule 4

Table 2
UNION GAS LIMITED
2015 Actual Cost of Capital Summary

Line No.		Principal (1) ($millions)	Component (1) %	Cost Rate (1) %	Return %	Return (1) ($millions)
1	Long term Debt	2,746.7	64.96%	5.64%	3.67%	155.0
2	Short Term Debt	-143.5	-3.39%	0.84%	-0.03%	-1.2
3	Preferred Shares	103.0	2.44%	2.58%	0.06%	2.7
4	Common Equity	1,522.2	36.00%	8.93%	3.21%	135.9
5	Total	4,228.4	100.00%		6.91%	292.4

Notes:
(1) EB-2016-0118, Exhibit A, Tab 2, Appendix A, Schedule 4

Table 3
UNION GAS LIMITED
2016 Actual Cost of Capital Summary

Line No.		Principal (1) ($millions)	Component (1) %	Cost Rate (1) %	Return %	Return (1) ($millions)
1	Long term Debt	3,161.5	66.44%	5.12%	3.40%	161.8
2	Short Term Debt	-219.5	-4.61%	0.82%	-0.04%	-1.8
3	Preferred Shares	103.4	2.17%	2.51%	0.05%	2.6
4	Common Equity	1,713.0	36.00%	8.93%	3.21%	153.0
5	Total	4,758.4	100.00%		6.63%	315.6

Notes:
(1) EB-2017-0091, Exhibit A, Tab 2, Appendix A, Schedule 4

Table 4
UNION GAS LIMITED
2017 Actual Cost of Capital Summary

Line No.		Principal (1) ($millions)	Component (1) %	Cost Rate (1) %	Return %	Return (1) ($millions)
1	Long term Debt	3,318.9	60.63%	4.98%	3.02%	165.3
2	Short Term Debt	80.2	1.47%	1.02%	0.01%	0.8
3	Preferred Shares	104.1	1.90%	2.66%	0.05%	2.8
4	Common Equity	1,970.5	36.00%	8.93%	3.21%	176.0
5	Total	5,473.6	100.00%		6.30%	344.9

Notes:
(1) Figures are expected to be included in the Application and Evidence for EB-2018-0105, but are draft at this time and may change.

Table 5
UNION GAS LIMITED
2018 Budget Cost of Capital Summary

Line No.		Principal ($millions)	Component %	Cost Rate %	Return %	Return ($millions)
1	Long term Debt	3,683.0	59.86%	4.50%	2.69%	165.7
2	Short Term Debt	150.3	2.44%	1.20%	0.03%	1.8
3	Preferred Shares	104.5	1.70%	2.74%	0.05%	2.9
4	Common Equity	2,215.0	36.00%	8.93%	3.22%	197.8
5	Total	6,152.8	100.00%		5.98%	368.2

2014 Utility Capital Structure – Actual vs. Approved

2014 ACTUAL UTILITY CAPITAL STRUCTURE

Line No.		Principal Incl. CC/CIS ($Millions)	Component %	Indicated Cost Rate %	Return Component %	Return ($Millions)
1.	Long term debt	2,705.7	57.55	5.41	3.113	146.4
2.	Short term debt	203.1	4.32	1.38	0.060	2.8
3.	Preference shares	100.0	2.13	2.40	0.051	2.4
4.	Common equity	1,692.5	36.00	9.36	3.370	158.4
5.		4,701.3	100.00		6.594	310.0

EB-2012-0459 2014 APPROVED UTILITY CAPITAL STRUCTURE

Line No.		Principal Incl. CC/CIS ($Millions)	Component %	Indicated Cost Rate %	Return Component %	Return ($Millions)
1.	Long term debt	2,633.9	59.57	5.57	3.316	146.6
2.	Short term debt	95.8	2.17	1.78	0.039	1.7
3.	Preference shares	100.0	2.26	2.96	0.067	3.0
4.	Common equity	1,591.7	36.00	9.35	3.365	148.8
5.		4,421.4	100.00		6.787	300.0

* Lower LTD rates acquired will be reflected and provide a benefit within 2015 through 2018 rates.

ENBRIDGE

2015 Utility Capital Structure – Actual vs. Approved

2015 ACTUAL UTILITY CAPITAL STRUCTURE

Line No.		Principal Incl. CC/CIS	Component	Indicated Cost Rate	Return Component	Return
		($Millions)	%	%	%	($Millions)
1.	Long term debt	2,985.7	58.78	5.15	3.030	153.9
2.	Short term debt	165.4	3.25	1.32	0.043	2.2
3.	Preference shares	100.0	1.97	2.24	0.044	2.2
4.	Common equity	1,828.7	36.00	9.30	3.348	170.1
5.		5,079.8	100.00		6.465	328.4

EB-2014-0276 2015 APPROVED UTILITY CAPITAL STRUCTURE

Line No.		Principal Incl. CC/CIS	Component	Indicated Cost Rate	Return Component	Return
		($Millions)	%	%	%	($Millions)
1.	Long term debt	3,002.2	60.57	5.14	3.114	154.3
2.	Short term debt	70.0	1.41	1.45	0.020	1.0
3.	Preference shares	100.0	2.02	2.20	0.044	2.2
4.	Common equity	1,784.3	36.00	9.29	3.345	165.8
5.		4,956.5	100.00		6.523	323.4

ENBRIDGE

2016 Utility Capital Structure – Actual vs. Approved

2016 ACTUAL UTILITY CAPITAL STRUCTURE

Line No.		Principal Incl. CC/CIS ($Millions)	Component %	Indicated Cost Rate %	Return Component %	Return ($Millions)
1.	Long term debt	3,472.8	58.77	4.95	2.909	171.9
2.	Short term debt	209.0	3.54	1.33	0.047	2.8
3.	Preference shares	100.0	1.69	2.16	0.037	2.2
4.	Common equity	2,127.2	36.00	9.19	3.308	195.5
5.		5,909.0	100.00		6.301	372.3

EB-2015-0114 / EB-2015-0049 2016 APPROVED UTILITY CAPITAL STRUCTURE

Line No.		Principal Incl. CC/CIS ($Millions)	Component %	Indicated Cost Rate %	Return Component %	Return ($Millions)
1.	Long term debt	3,566.8	61.42	4.96	3.048	177.0
2.	Short term debt	49.6	0.85	1.57	0.013	0.8
3.	Preference shares	100.0	1.72	2.16	0.037	2.2
4.	Common equity	2,090.5	36.00	9.19	3.307	192.0
5.		5,806.9	100.00		6.405	371.9

Witness: L. Stickles

PRELIMINARY 2017 ACTUAL UTILITY CAPITAL STRUCTURE

Line No.		Principal Incl. CC/CIS	Component	Indicated Cost Rate	Return Component	Return
		($Millions)	%	%	%	($Millions)
1.	Long term debt	3,677.3	56.88	4.86	2.764	178.7
2.	Short term debt	360.4	5.57	1.05	0.058	3.8
3.	Preference shares	100.0	1.55	2.32	0.036	2.3
4.	Common equity	2,327.5	36.00	8.78	3.161	204.4
5.		6,465.2	100.00		6.019	389.1

EB-2016-0215 2017 APPROVED UTILITY CAPITAL STRUCTURE

Line No.		Principal Incl. CC/CIS	Component	Indicated Cost Rate	Return Component	Return
		($Millions)	%	%	%	($Millions)
1.	Long term debt	3,752.2	62.29	4.83	3.009	181.3
2.	Short term debt	3.2	0.05	1.23	0.001	0.0
3.	Preference shares	100.0	1.66	2.24	0.037	2.2
4.	Common equity	2,168.7	36.00	8.78	3.160	190.4
5.		6,024.1	100.00		6.207	374.0

EB-2017-0086 2018 APPROVED UTILITY CAPITAL STRUCTURE

Line No.		Principal Incl. CC/CIS	Component	Indicated Cost Rate	Return Component	Return
		($Millions)	%	%	%	($Millions)
1.	Long term debt	3,862.7	61.84	4.70	2.907	181.6
2.	Short term debt	34.8	0.56	1.60	0.009	0.6
3.	Preference shares	100.0	1.60	2.72	0.044	2.7
4.	Common equity	2,248.6	36.00	9.00	3.240	202.4
5.		6,246.1	100.00		6.200	387.3

MR. BUONAGURO: Can you explain why it seems to me you are using an inflation figure over 2 percent, while Enbridge is using an inflation figure over 2 percent. Why are you using two different inflation figures?

MR. REINISCH: Again, both of these cost forecasts were developed independently. They were developed by Union Gas for Union, and by EGD for EGD. Both utilities have been operating under different IRM frameworks for the last number of years, and have been facing different cost pressures and have different productivity potential.

But again, in both cases there is a marginal difference of 2 percent versus 1.73 percent inflation per year when you go out past 2021, and again the key there is that the forecasts were developed independently, factoring in all the available information we had at the time.

MR. BUONAGURO: In terms of -- you said one there that I'm interested in. You said they have different productivity -- what was the word -- potential.

But if I'm not mistaken, there's no productivity assumed in any of these escalations, correct, by either company?

[Witness panel confers]

MR. REINISCH: So there is an implicit productivity for both forecasts.

There are customer attachments each year. Roughly 50,000 customers combined for Amalco; about 30,000 for Enbridge and 20,000 for Union Gas.

These incremental customers come with incremental costs, postage, billing, et cetera.

There is no -- as you can see in this breakdown, there is no assumption for increased costs associated with those customers. So there is embedded in these assumptions some level of productivity that will need to be achieved to fund the increased costs associated with the attaching 50,000 customers a year.

MR. BUONAGURO: There is also increased revenue, correct? When you add a customer, they become a customer and they start paying bills?

MR. REINISCH: Yes, there will be increased revenue, but that revenue is required to cover all costs, not just O&M.

MR. BUONAGURO: Well, that's true of every utility that's ever been, right? I mean, you are not describing anything new that is specific to Enbridge and Union?

MR. REINISCH: Again, it is important to note, though, that when we look at the custom IR, we the are not looking at revenues from customers. We are looking at a cost-based approach, and so we are discussing costs in this instance, not the revenues associated with customers.

MR. BUONAGURO: So from a productivity point of view, when I asked the question about productivity potential, you are telling me that the productivity that you've embedded in your forecast per custom IR is productivity associated with adding customers?

MR. REINISCH: That is correct. We've assumed that there is no incremental cost to add 50,000 customers a year

-- an assumption that is in essence false, because we know there is cost associated with adding customers. But we have not included that in our custom IR proposal.

MR. BUONAGURO: And then line 3, as Mr. Kitchen jumped to, has the differential between volumes 1 and 2.

I have used the number 411, because that's what's in the exhibit. If you do the actual math in my spreadsheet, it is a little off. It’s a million, which I assume has to do with rounding.

MR. KITCHEN: It would be rounding.

MR. BUONAGURO: And this is one of the lynchpins, I’d call it, of your proposal in the sense that it’s the 411 benefit -- a ratepayer benefit, as I think you refer to it As -- justifies your rate proposal.

MR. KITCHEN: The $411 million is what we've used to show that there's no harm, to put forward the no-harm test, and it is the result of our rate proposal, yes.

MR. BUONAGURO: I see. So you're not claiming that this math justifies your rate proposal?

MR. KITCHEN: Well, I believe what I am saying is we have brought forward a proposal to amalgamate. In order to do the no-harm test, we looked at what two the stand-alone utilities would look like compared to our price cap proposal. That generates $411 million in savings to ratepayers through the no-harm test, right?

We are applying -- we are applying for a rate mechanism under a price cap, and we are applying for a zero productivity, zero stretch factor, and a number of other

UNION GAS LIMITED
Revenue Requirement of the Milverton Community Expansion Project

Line No.	Particulars ($000's)	2016 (a)	2017 (b)	2018 (c)
	Rate Base Investment			
1	Capital Expenditures	4,259	179	80
2	Average Investment	1,391	4,203	4,231
	Revenue Requirement Calculation:			
	Operating Expenses:			
3	Operating and Maintenance Expenses (1)	1	7	14
4	Depreciation Expense (2)	57	117	120
5	Property Taxes	16	49	49
6	Total Operating Expenses	75	173	183
7	Required Return (5.77% x line 2) (3)	80	243	244
	Income Taxes:			
8	Income Taxes - Equity Return (4)	16	49	49
9	Income Taxes - Utility Timing Differences (5)	(25)	(49)	(45)
10	Total Income Taxes	(9)	(0)	4
11	Total Revenue Requirement (line 6 + line 7 + line 10)	146	416	431
12	Incremental Revenue (6)	63	62	96
13	Net Revenue Requirement (line 11 - line 12)	84	354	335

Notes:
(1) Operating and Maintenance expenses include distribution expenses associated with attaching a new customer.
(2) Depreciation expense at 2013 Board-approved depreciation rates.
(3) The required return of 5.77% assumes a capital structure of 64% long-term debt at 4.0% and 36% common equity at the 2013 Board-approved return of 8.93% (0.64 x 0.04 + 0.36 x 0.0893).

The 2018 required return calculation is as follows:
$4.231 million x 64% x 4.0% = $0.108 million plus
$4.231 million x 36% x 8.93% = $0.136 million for a total of $0.244 million.

(4) Taxes related to the equity component of the return at a tax rate of 26.5%.
(5) Taxes related to utility timing differences are negative as the capital cost allowance deduction in arriving at taxable income exceeds the provision of book depreciation in the year.
(6) Incremental revenue associated with forecast customer attachments based on an average Union North and Union South residential and commercial customer.

UNION GAS LIMITED
Revenue Requirement of the Prince Township Community Expansion Project

Line No.	Particulars ($000's)	2016 (a)	2017 (b)	2018 (c)
	Rate Base Investment			
1	Capital Expenditures	2,278	150	52
2	Average Investment	744	2,266	2,319
	Revenue Requirement Calculation:			
	Operating Expenses:			
3	Operating and Maintenance Expenses (1)	1	4	8
4	Depreciation Expense (2)	31	63	66
5	Property Taxes	8	25	25
6	Total Operating Expenses	40	92	99
7	Required Return (5.77% x line 2) (3)	43	131	134
	Income Taxes:			
8	Income Taxes - Equity Return (4)	9	26	27
9	Income Taxes - Utility Timing Differences (5)	(14)	(27)	(25)
10	Total Income Taxes	(5)	(0)	2
11	Total Revenue Requirement (line 6 + line 7 + line 10)	78	223	235
12	Incremental Revenue (6)	59	45	67
13	Net Revenue Requirement (line 11 - line 12)	19	178	167

Notes:
(1) Operating and Maintenance expenses include distribution expenses associated with attaching a new customer.
(2) Depreciation expense at 2013 Board-approved depreciation rates.
(3) The required return of 5.77% assumes a capital structure of 64% long-term debt at 4.0% and 36% common equity at the 2013 Board-approved return of 8.93% (0.64 x 0.04 + 0.36 x 0.0893).

The 2018 required return calculation is as follows:
$2.319 million x 64% x 4.0% = $0.059 million plus
$2.319 million x 36% x 8.93% = $0.075 million for a total of $0.134 million.
(4) Taxes related to the equity component of the return at a tax rate of 26.5%.
(5) Taxes related to utility timing differences are negative as the capital cost allowance deduction in arriving at taxable income exceeds the provision of book depreciation in the year.
(6) Incremental revenue associated with forecast customer attachments based on an average Union North and Union South residential and commercial customer.

UNION GAS LIMITED
Revenue Requirement of the Chippewa's of Kettle and Stony Point First Nation and Lambton Shores
Community Expansion Project

Line No.	Particulars ($000's)	2016 (a)	2017 (b)	2018 (c)
	Rate Base Investment			
1	Capital Expenditures	2,169	84	32
2	Average Investment	708	2,138	2,144
	Revenue Requirement Calculation:			
	Operating Expenses:			
3	Operating and Maintenance Expenses (1)	1	4	8
4	Depreciation Expense (2)	29	59	61
5	Property Taxes	8	24	24
6	Total Operating Expenses	38	88	93
7	Required Return (5.77% x line 2) (3)	41	123	124
	Income Taxes:			
8	Income Taxes - Equity Return (4)	8	25	25
9	Income Taxes - Utility Timing Differences (5)	(13)	(25)	(23)
10	Total Income Taxes	(5)	(0)	2
11	Total Revenue Requirement (line 6 + line 7 + line 10)	74	211	219
12	Incremental Revenue (6)	59	45	63
13	Net Revenue Requirement (line 11 - line 12)	15	166	156

Notes:

(1) Operating and Maintenance expenses include distribution expenses associated with attaching a new customer.

(2) Depreciation expense at 2013 Board-approved depreciation rates.

(3) The required return of 5.77% assumes a capital structure of 64% long-term debt at 4.0% and 36% common equity at the 2013 Board-approved return of 8.93% (0.64 x 0.04 + 0.36 x 0.0893).

The 2018 required return calculation is as follows:
$2.144 million x 64% x 4.0% = $0.055 million plus
$2.144 million x 36% x 8.93% = $0.069 million for a total of $0.124 million.

(4) Taxes related to the equity component of the return at a tax rate of 26.5%.

(5) Taxes related to utility timing differences are negative as the capital cost allowance deduction in arriving at taxable income exceeds the provision of book depreciation in the year.

(6) Incremental revenue associated with forecast customer attachments based on an average Union North and Union South residential and commercial customer.

UNION GAS LIMITED
Revenue Requirement of the Walpole Island First Nation Community Expansion Project

Line No.	Particulars ($000's)	2016 (a)	2017 (b)	2018 (c)
	Rate Base Investment			
1	Capital Expenditures	1,247	5	3
2	Average Investment	407	1,215	1,186
	Revenue Requirement Calculation:			
	Operating Expenses:			
3	Operating and Maintenance Expenses (1)	1	2	4
4	Depreciation Expense (2)	17	34	34
5	Property Taxes	9	27	27
6	Total Operating Expenses	27	64	65
7	Required Return (5.77% x line 2) (3)	24	70	68
	Income Taxes:			
8	Income Taxes - Equity Return (4)	5	14	14
9	Income Taxes - Utility Timing Differences (5)	(7)	(14)	(13)
10	Total Income Taxes	(3)	(0)	1
11	Total Revenue Requirement (line 6 + line 7 + line 10)	47	134	135
12	Incremental Revenue (6)	4	16	25
13	Net Revenue Requirement (line 11 - line 12)	43	117	109

Notes:
(1) Operating and Maintenance expenses include distribution expenses associated with attaching a new customer.
(2) Depreciation expense at 2013 Board-approved depreciation rates.
(3) The required return of 5.77% assumes a capital structure of 64% long-term debt at 4.0% and 36% common equity at the 2013 Board-approved return of 8.93% (0.64 x 0.04 + 0.36 x 0.0893).

The 2018 required return calculation is as follows:
$1.186 million x 64% x 4.0% = $0.030 million plus
$1.186 million x 36% x 8.93% = $0.038 million for a total of $0.068 million.

(4) Taxes related to the equity component of the return at a tax rate of 26.5%.
(5) Taxes related to utility timing differences are negative as the capital cost allowance deduction in arriving at taxable income exceeds the provision of book depreciation in the year.
(6) Incremental revenue associated with forecast customer attachments based on an average Union North and Union South residential and commercial customer.

UNION GAS LIMITED
Revenue Requirement of the Delaware Nation of Moraviantown Community Expansion Project

Line No.	Particulars ($000's)	2016 (a)	2017 (b)	2018 (c)
	Rate Base Investment			
1	Capital Expenditures	539	4	2
2	Average Investment	176	526	515
	Revenue Requirement Calculation:			
	Operating Expenses:			
3	Operating and Maintenance Expenses (1)	0	2	3
4	Depreciation Expense (2)	7	15	15
5	Property Taxes	2	5	5
6	Total Operating Expenses	10	22	23
7	Required Return (5.77% x line 2) (3)	10	30	30
	Income Taxes:			
8	Income Taxes - Equity Return (4)	2	6	6
9	Income Taxes - Utility Timing Differences (5)	(3)	(6)	(5)
10	Total Income Taxes	(1)	(0)	0
11	Total Revenue Requirement (line 6 + line 7 + line 10)	19	52	53
12	Incremental Revenue (6)	56	30	32
13	Net Revenue Requirement (line 11 - line 12)	(38)	22	21

Notes:
(1) Operating and Maintenance expenses include distribution expenses associated with attaching a new customer.
(2) Depreciation expense at 2013 Board-approved depreciation rates.
(3) The required return of 5.77% assumes a capital structure of 64% long-term debt at 4.0% and 36% common equity at the 2013 Board-approved return of 8.93% (0.64 x 0.04 + 0.36 x 0.0893).

The 2018 required return calculation is as follows:
$0.515 million x 64% x 4.0% = $0.013 million plus
$0.515 million x 36% x 8.93% = $0.017 million for a total of $0.030 million.

(4) Taxes related to the equity component of the return at a tax rate of 26.5%.
(5) Taxes related to utility timing differences are negative as the capital cost allowance deduction in arriving at taxable income exceeds the provision of book depreciation in the year.
(6) Incremental revenue associated with forecast customer attachments based on an average Union North and Union South residential and commercial customer.

ENBRIDGE GAS DISTRIBUTION INC. AND UNION GAS LIMITED

Answer to Interrogatory from
Federation of Rental-housing Providers of Ontario ("FRPO")

Reference: EB-2017-0307, Exhibit B, Tab 1, Page 3

Preamble: "*As the Applicants are not part of this annual Board process, this Application proposes an inflation factor and productivity factor that are modelled on Price Cap IR.*"

Union Gas has been under a price cap with an inflation adjustment factor which has been used as a productivity factor. With that productivity factor limiting inflationary rate increases, we would like to understand how Union has performed financially relative to the Board approved return on equity.

Question:
Using the actual inflation rate incorporated into the establishment of annual rates, for each of the IR years, in tabular fashion, please provide:

a. The inflation factor approved by the Board for rates
b. The effective productivity factor for each of the years of 2014 to 2017 (i.e., 60% of the inflation determined for that year).
c. The Board-approved percentage rate of return on equity
d. The actual percentage rate of return on equity

Response

a- d) Please see Table1 provided on the following page.

Table 1
2014 – 2017 Price Cap Index Factors and Return on Equity

Line No.	Particulars	**2014** (1)	**2015** (2)	**2016** (3)	**2017** (4)
1	Inflation factor	1.27%	2.05%	1.99%	1.66%
2	Productivity factor (60% of line 1)	0.76%	1.23%	1.19%	1.00%
3	Price Cap Index (line 1- line 2)	0.51%	0.82%	0.80%	0.66%
4	Board-approved return on equity	8.93%	8.93%	8.93%	8.93%
5	Actual return on equity	10.69%	9.89%	9.24%	9.15%

Notes:

(1) Price cap index factors from EB-2013-0365, Rate Order, Working Papers, Schedule 1, line 6. Return on equity figures from EB-2015-0010, Exhibit A, Tab 2, p. 3.
(2) Price cap index factors from EB-2014-0271, Rate Order, Working Papers, Schedule 1, line 6. Return on equity figures from EB-2016-0118, Exhibit A, Tab 2, p. 4.
(3) Price cap index factors from EB-2015-0116, Rate Order, Working Papers, Schedule 1, line Return on equity figures from EB-2017-0091, Exhibit A, Tab 2, p. 3.
(4) Price cap index factors from EB-2016-0245, Rate Order, Working Papers, Schedule 1, line 6. Actual return on equity figure is expected to be included in the Application and Evidence for EB-2018-0105, but is draft at this time and may change.

here have nothing to do with what we are requesting currently before the Board.

MR. SHEPHERD: So you are not requesting to calculate it this way?

MR. REINISCH: Not for 2013 through 2018. There was no ICM threshold for Union Gas.

MR. SHEPHERD: You are deliberately avoiding my question. Please don't. It's a very straightforward question. There is a methodology that you are proposing in this application to calculate the amount for which you'll ask for extra money. If you applied that methodology in the last six years, you would get both lines 7 and 8 included in extra money; right? Isn't that your current proposal?

MR. REINISCH: So again, if we had the ICM in place and we had made the exact same spending and investment decisions that we made under a different framework, then, yes, we would have been asking for recovery of incremental dollars, assuming that those projects that underpin that spending would have met all of the ICM eligibility criteria of the Board.

MR. SHEPHERD: We're going to come back to that, but the reason I ask that is because, am I right that from 2013 to 2018 Union earned more than its allowed ROE in every year?

MR. TETREAULT: Yes, that's correct, Jay.

MR. SHEPHERD: So even though you spent this extra money you still managed to earn your allowed ROE, and so be the growth capital, would represent the other 50 percent, so that is the --

MR. SHEPHERD: Oh, so --

MR. REINISCH: -- total capital investment.

MR. SHEPHERD: So let me ask you about that: You have this line that is ICM-eligible, and what you've -- the approach you've taken to ICM-eligible is you are assuming that anything over the threshold qualifies; right?

MR. REINISCH: With a small amount of -- a few adjustments, a few million dollars during certain years, that is correct. We've assumed that everything above the threshold is ICM-eligible projects.

Obviously, before we take a project to the board we will have to have a project, and it will have to meet all of the eligibility criteria.

MR. SHEPHERD: But your current expectation is that pretty well all of the ICM -- all of the amounts above the threshold will be recoverable through the ICM mechanism; right?

MR. REINISCH: So that was a simplifying assumption that was used to model. Ultimately, we will have to go through each asset plan before we file for cost recovery of any individual ICM project, and assess whether it meets all of the Board's eligibility criteria.

MR. SHEPHERD: This line of ICM eligible $2.5 billion, this is -- some of that is going to be attachments and maintenance as you've defined it, right?

Those are your two big categories, so if it's not in

Scenario 1: ***ICM revenue requirement calculated based on first year of introduction (current ICM policy and standard CoS approach)***

Years	Depreciation Rate	Debt Rate		ROE		Tax Rate
33	3.03%	5%	65%	9.25%	35%	26.25%

		Opening NBV	Closing NBV	Average NBV	Debt Cost ($M)	ROE ($M)	Tax (grossed up)	Depreciation	Revenue Requirement	Change in Revenue Requirement: Year over year change	Change in Revenue Requirement: Change from the start
Year 1	2019	100.000	96.970	98.485	3.201	3.188	1.135	3.030	10.554		
Year 2	2020	96.970	93.939	95.455	3.102	3.090	1.100	3.030	10.323	2.2%	2.2%
Year 3	2021	93.939	90.909	92.424	3.004	2.992	1.065	3.030	10.091	2.2%	4.4%
Year 4	2022	90.909	87.879	89.394	2.905	2.894	1.030	3.030	9.860	2.3%	6.6%
Year 5	2023	87.879	84.848	86.364	2.807	2.796	0.995	3.030	9.628	2.3%	8.8%
Year 6	2024	84.848	81.818	83.333	2.708	2.698	0.960	3.030	9.397	2.4%	11.0%
Year 7	2025	81.818	78.788	80.303	2.610	2.600	0.925	3.030	9.165	2.5%	13.2%
Year 8	2026	78.788	75.758	77.273	2.511	2.502	0.890	3.030	8.934	2.5%	15.4%
Year 9	2027	75.758	72.727	74.242	2.413	2.404	0.856	3.030	8.702	2.6%	17.5%
Year 10	2028	72.727	69.697	71.212	2.314	2.305	0.821	3.030	8.471	2.7%	19.7%
								Revenue requirement over 10 years (2019-2028)	**95.126**		

Scenario 1: ***ICM revenue requirement calculated based on first year of introduction (current ICM policy and standard CoS approach)***

Year 1	2019	100.000	96.970	98.485	3.201	3.188	1.135	3.030	10.554

2019-2028 Period (Cumulative)

	Revenues from ICM Rate Rider	Actual Revenue Requirement	Over-collection	
	$M	$M	$M	%
Based on year 1 (2018) incremental revenue requirement X 10 years	105.544	**95.126**	10.418	11.0

Scenario 2: ***ICM revenue requirement calculated based on average NBV from first year of introduction up until rebasing***

ICM Rev Reqt, if based on average NBV over period	100.000	69.697	84.848	2.758	2.747	0.978	3.030	9.513

2019-2028 Period (Cumulative)

	Revenues from ICM Rate Rider	Actual Revenue Requirement	Over-collection	
	$M	$M	$M	%
Based on average NBV incremental revenue requirement X 10 years	95.126	**95.126**	-	-

Capital Expenditures and Depreciation 2014-2028

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Union Gas															
Capex	477	691	1034	721	558	587	429	450	438	609	589	426	423	436	436
Depreciation	200	212	228	255	283	298	319	330	340	353	369	382	393	404	415
Percentage	238.0%	325.6%	452.7%	282.9%	197.5%	197.0%	134.6%	136.4%	128.7%	172.3%	159.4%	111.5%	107.7%	107.9%	105.0%
Average					295.4%										133.8%
Union Gas - Excluding Passthroughs															
Capex	322	339	343	353	443	587	429	450	438	609	589	426	423	436	436
Depreciation	200	207	212	222	239	254	275	286	297	310	325	339	349	360	371
Percentage	161.2%	164.1%	161.6%	158.8%	185.1%	230.8%	156.0%	157.3%	147.6%	196.6%	180.8%	125.9%	121.2%	121.0%	117.4%
Average					166.6%										152.3%
Enbridge															
Capex	612	1015	594	431	442	633	724	575	635	577	586	610	820	594	601
Depreciation	256	260	293	301	306	328	349	367	382	392	401	411	419	428	439
Percentage	239.3%	391.0%	202.9%	143.1%	144.7%	193.3%	207.5%	156.7%	166.4%	147.4%	146.0%	148.3%	195.7%	138.9%	136.9%
Average					218.7%										162.3%
Total Amalco															
Capex	1089	1706	1628	1152	1000	1220	1153	1025	1073	1186	1174	1036	1243	1030	1037
Depreciation	456	472	521	556	588	626	668	697	722	745	770	794	812	832	854
Percentage	238.7%	361.6%	312.4%	207.2%	170.0%	195.0%	172.7%	147.1%	148.6%	159.2%	152.4%	130.6%	153.1%	123.9%	121.4%
Average					253.5%										148.7%

Sources: 2019-2028 from FRPO 11
Union Dep'n 2014-2017 from Staff 7
Union Capex 2014-2018 from LPMA 23
EGD Dep'n 2014-2018 from SEC 19

I just want to confirm, the $400 million, your stand-alone scenario -- I think Mr. Shepherd took you through this today -- it's based on no sharing of staff and no rationalization of activities; is that correct?

MR. REINISCH: Yes, that's correct.

MS. GIRVAN: Okay. Thank you.

And I had a question regarding real estate. If you amalgamate and you end up selling properties, which I expect you'll do, how will you deal with the gains or losses on those properties during the planned term?

MR. KITCHEN: Well, first of all, we were just discussing the fact that we can't think of a situation where we would be selling property as a result of the amalgamation. There are a number of properties that we currently lease, and we'd look to utilizing -- utilizing existing properties first.

And until we actually do an integration plan I'm not sure that we can speculate on what property would be sold and whether or not there would be a gain or a loss, but to the extent that there was a gain or a loss, it would be to the account of the shareholder.

MS. GIRVAN: Okay, thank you.

And I think I just -- just one more question. I just want to be clear on this.

With respect to your specific plan, Union or Enbridge never undertook customer engagement, specifically around the savings and the other elements of your plan.

MR. CULBERT: Pardon me, I'm just looking up a

ENBRIDGE GAS DISTRIBUTION INC. AND UNION GAS LIMITED

Undertaking of Mr. Kitchen
To Mr. Shepherd

REF: Tr.4, p.205

To re-calculate savings shown in FRPO 11 using a stretch factor of 0.3 percent

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The Applicants were asked to re-calculate the ratepayer benefit over the deferred rebasing period using a stretch factor of 0.3 percent[1]. The discussion during the oral hearing related to the application of the 0.3 percent in a manner that is consistent with the original calculation of the ratepayer benefit. The pre-filed evidence shows the ratepayer benefit is $410 million over the deferred rebasing period when comparing Amalco's revenues under the Price Cap Index (PCI) with the aggregate revenues of two standalone utilities operating under a Custom IR model (Standalone Revenues), with no external stretch factor applied in either scenario. This undertaking response re-calculates the ratepayer benefits with a 0.3 percent stretch factor applied to both the Standalone Revenues and Amalco's revenues under the PCI at inflation. The result is a ratepayer benefit of $433 million (up from $410 million) but on significantly reduced revenues. The derivation of the results is described below, and the results are presented in two tables, also below.

As noted in testimony during the oral hearing, Dr. Makholm provided an expert opinion that there should be no stretch factor. The original evidence no-harm test and savings amount of $410 million, produced from comparing the use of a price cap for Amalco versus stand-alone cost projections under custom IR, is in no way related to the calculation amount of $410 million from applying a 0.3% stretch to the price cap formula proposed by the applicants but rather is completely coincidental. The Applicants stated that the application of a 0.3 percent stretch factor would result in Amalco needing to achieve an additional $410 million in integration savings to meet its ten year business plan and achieve the annual allowed ROE[2]. The significant reduction to revenues that results from a 0.3 percent stretch factor would also have detrimental operational and business implications. Where Amalco's operating expenses are forecasted to increase annually at a rate just below 2 percent per year over the ten years, applying a stretch factor of $410 million would effectively remove any inflation increase and effectively decrease operating expense forecasts over the ten year period.

The applicants have also noted in testimony that stretch amounts have been included in the revenue projections of the Amalco rate proposal. Amalco's revenues are carrying forward the $4.5 million productivity commitment[3] and a PCI that is equal to 40% of inflation in Union Gas's 2014 to 2018 IRM. Amalco has $60 million of additional unidentified efficiencies[4] over

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[1] EB-2017-0306-0307 Oral Hearing Transcript Day 4, Page 204, Line 10 -20
[2] EB-2017-0306-0307 Oral Hearing Transcript Day 2, Page 134, Line 15 -26
[3] EB-2017-0306-0307 Oral Hearing Transcript Day 1, Page 130, Line 2- 11
[4] EB-2017-0306 Exhibit B, Tab 1, Attachment 12

the deferred rebasing period that are required to be found in order for it to achieve the forecasted 20 basis points in excess of the average ten year allowed ROE. In effect these are an embedded stretch amount which Amalco will have to deal with from a revenue shortfall perspective. The application of a stretch factor of any magnitude is in fact adding incremental stretch on top of the existing embedded stretch that resides in Amalco's rate proposal.

Based on that evidence, the Applicants take the position that an incremental 0.3% stretch factor is inappropriate. Nevertheless, the Applicants have re-calculated the ratepayer benefit with a 0.3 percent stretch factor in order to be responsive to the undertaking.

Re-Calculation Summary

To re-calculate the ratepayer benefit, the Applicants calculated the revenue reduction for both the Standalone Revenues and Amalco rate proposal with the application of a 0.3 percent stretch. For the Amalco rate proposal, this re-calculation was performed in Exhibit K2.3, line 12. The exhibit shows that the total revenues would be reduced by $410 million. The application of the stretch factor to the Standalone Revenues results in a total revenue reduction of $387 million. The details of this re-calculation are outlined in the section below titled "***Calculation Method for applying 0.3 percent stretch factor to Standalone Revenues***". Both revenue reduction amounts are cumulative and represent the impact over the ten year deferred rebasing period.

To re-calculate the savings when the 0.3 stretch is applied, the pre-filed ratepayer benefit of $410 million was adjusted for the impact of stretch being applied to both Standalone Revenues and revenues under the Amalco rate proposal. This re-calculation is set out in Table 1 below.

Re-Calculation of savings applying a 0.3 percent stretch factor

Table 1: Impact on revenues with 0.3% stretch factor

$ Millions	2019-2028	Notes
1.1 Ratepayer benefit - Applicants Pre-Filed Evidence	410	A
1.2 Additional ratepayer benefit with stretch factor in Amalco PCI revenues	410	B
1.3 Total ratepayer benefit	820	
1.4 Reduction to ratepayer benefit with stretch factor in Standalone Revenues	(387)	Table 2
1.5 Net ratepayer benefit due to stretch factor	433	

Notes:
A. Reference: Table 3 in MAAD application EB-2017-0306, Exhibit B, T1, page 20 of 44
B. Reference: OGVG compendium K2.3, line 12

Calculation Method for applying 0.3 percent stretch factor to Standalone Revenues

To re-calculate the savings the Standalone Revenues were reduced by 0.3 percent using the following steps:

- Translated the annual increase in revenues, net of flow-through items, into a Custom IR Index (year over year percentage change), with 2019 being the rebasing year
- Reduced the custom IR index annual change percentage by 0.3 percent to establish a new set of Standalone Revenues
- Compared the new set of Standalone Revenues to the original Standalone Revenues to determine the reduction in ratepayer benefit (value in line 1.4 of Table 1)

Table 2: Impact of 0.3% stretch factor on EGD and Union standalone revenues

$ Millions	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2019-2028	
1.1 EGD & Union												
Custom IR Revenues - As filed	2,531	2,657	2,767	2,850	2,932	3,014	3,103	3,174	3,268	3,351	29,648	A = D+G
Custom IR Revenues with 0.3% stretch factor	2,531	2,650	2,752	2,826	2,900	2,973	3,052	3,113	3,196	3,268	29,261	B = E+H
Change in Custom IR Revenues with stretch factor	-	(7)	(15)	(23)	(32)	(41)	(51)	(61)	(72)	(83)	(387)	C = B-A
2.1 **EGD - $ Millions**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2019-2028**	
Custom IR Revenues - As filed												
Total Revenues *(from Table 2 in FRPO 11a)*	1,300	1,357	1,428	1,473	1,516	1,546	1,592	1,629	1,693	1,738	15,272	D
Less flow through: DSM *(from Table 1 in FRPO 11a)*	66	68	68	69	70	71	73	74	75	76		
Net Revenues	1,234	1,289	1,360	1,404	1,446	1,475	1,520	1,555	1,617	1,661		
Custom IR index - Revenue growth		4.49%	5.47%	3.25%	2.98%	2.01%	3.04%	2.34%	4.00%	2.71%		
Custom IR revenues with stretch factor												
Custom IR index - Revenue growth		*4.49%*	*5.47%*	*3.25%*	*2.98%*	*2.01%*	*3.04%*	*2.34%*	*4.00%*	*2.71%*		
stretch factor		*-0.30%*	*-0.30%*	*-0.30%*	*-0.30%*	*-0.30%*	*-0.30%*	*-0.30%*	*-0.30%*	*-0.30%*		
Custom IR index with stretch factor - Revenue growth		*4.19%*	*5.17%*	*2.95%*	*2.68%*	*1.71%*	*2.74%*	*2.04%*	*3.70%*	*2.41%*		
Revenues with stretch factor	1,234	1,286	1,352	1,392	1,429	1,454	1,493	1,524	1,580	1,618		
DSM *(from Table 1 in FRPO 11a)*	66	68	68	69	70	71	73	74	75	76		
Total Custom IR Revenues with stretch factor	1,300	1,353	1,420	1,461	1,499	1,525	1,566	1,598	1,655	1,695	15,073	E
Variance from base case	-	(4)	(8)	(12)	(17)	(21)	(26)	(31)	(37)	(43)	(199)	F
2.2 **Union - $ Millions**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2019-2028**	
Custom IR Revenues - As filed												
Total Revenues *(from Table 6 in FRPO 11a)*	1,231	1,300	1,340	1,377	1,416	1,468	1,511	1,545	1,575	1,614	14,376	G
Less flow through: DSM *(from Table 5 in FRPO 11a)*	63	63	63	63	63	63	63	63	63	63		
Net Revenues	1,168	1,237	1,277	1,314	1,353	1,405	1,448	1,482	1,512	1,551		
Custom IR index - Revenue growth		5.96%	3.19%	2.90%	3.04%	3.82%	3.06%	2.31%	2.07%	2.53%		
Custom IR revenues with stretch factor												
Custom IR index - Revenue growth		*5.96%*	*3.19%*	*2.90%*	*3.04%*	*3.82%*	*3.06%*	*2.31%*	*2.07%*	*2.53%*		
stretch factor		*-0.30%*	*-0.30%*	*-0.30%*	*-0.30%*	*-0.30%*	*-0.30%*	*-0.30%*	*-0.30%*	*-0.30%*		
Custom IR index with stretch factor - Revenue growth		*5.66%*	*2.89%*	*2.60%*	*2.74%*	*3.52%*	*2.76%*	*2.01%*	*1.77%*	*2.23%*		
Revenues with stretch factor	1,168	1,234	1,269	1,302	1,338	1,385	1,423	1,452	1,478	1,511		
DSM *(from Table 5 in FRPO 11a)*	63	63	63	63	63	63	63	63	63	63		
Total Custom IR Revenues with stretch factor	1,231	1,297	1,332	1,365	1,401	1,448	1,486	1,515	1,541	1,574	14,188	H
Variance from base case	-	(4)	(7)	(11)	(16)	(20)	(25)	(30)	(35)	(40)	(188)	I

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

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.

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.