May 23, 2018

BY COURIER & RESS

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

Dear Ms. Walli,

RE: EB-2017-0306/ EB-2017-0307 – Enbridge Gas Distribution Inc. and Union Gas Limited – Undertaking Responses

Further to the submission on May 17, 2018, enclosed please find the following undertaking responses:

- J2.5 (updated);
- J3.3;
- J3.5;
- J3.7;
- J4.1;
- J5.1; and,
- J5.2.

The Applicants propose that the additional cross examination on May 28 focus on the undertaking responses to J2.4 and J4.1, with Panel 1 in attendance. Unless there are any questions with respect to the updated information provided in response to J2.5, the Applicants do not believe that Panel 2 needs to attend on May 28. Additionally, there should be no need for Panel 3 to attend on May 28.

If you have any questions with respect to this submission please contact me at 519-436-5334.

Yours truly,

[Original signed by]

Vanessa Innis
Manager, Regulatory Applications

Encl.

c.c.: Andrew Mandyam, EGD
Mark Kitchen, Union
Fred Cass, Aird & Berlis
EB-2017-0306/EB-2017-0307 Intervenors

ENBRIDGE GAS DISTRIBUTION INC. AND UNION GAS LIMITED

Undertaking of Mr. Kitchen
To Mr. Quinn

REF: Tr.2, p.176

To provide information on the settlement agreement

Please see Attachment 1 for information related to Union's Dawn-Parkway System demand and capacity and information on Union's Parkway Delivery Obligation ("PDO") shift for the years 2013 to 2018. Information on the 2017 Dawn-Parkway Project (EB-2015-0200) Settlement Agreement can be found at Attachment 1, Note 6.

UNION GAS LIMITED
Dawn to Parkway System Capacity and Demand, PDO Shift Details, and PDO Demand Revenue Difference

Line No.	Particulars (TJ/d)	2013 Forecast W13/14	W14/15	W15/16	W16/17	W17/18
		(a)	(b)	(c)	(d)	(e)
	Dawn-Parkway System					
	Included in Rates					
1	2013 Cost of Service (EB-2011-0210) Capacity	6,803	6,803	6,803	6,803	6,803
2	Incremental Dawn-Parkway Capacity (1)	-	-	433	876	1,332
3	Total	6,803	6,803	7,236	7,678	8,135
	Other Changes (No Impact to Rates)					
4	Other Dawn-Parkway Capacity Changes	-	(2)	(222)	(170)	(246)
	Annual Forecast					
5	Total Forecasted Dawn-Parkway Capacity	6,803	6,801	7,014	7,508	7,889
6	Total Forecasted Dawn-Parkway Demands	6,593	6,643	7,049	7,443	7,783
7	Forecast Dawn-Parkway Excess/(Shortfall) (line 5 - line 6) (2)	210 (3)	158	(35) (5)	65	106 (6)
	PDO Shift					
	Customers without M12 service					
8	Temporarily Available Capacity	-	146	23	13	-
9	Permanent Capacity (from Dawn-Kirkwall Turnback) (5)	-	-	123	133	200
10	Total	-	146 (4)	146	146	200
	Customers with M12 service - Permanent Capacity					
11	All Customers excluding TCE Halton Hills	-	19	19	19	19
12	TCE Halton Hills	-	48	48	48	62
13	Total	-	66	66	66	81
14	Total PDO Shift (line 10 + line 13)	-	212	212	212	280
	PDO Shift cost in Rates		2015 Rates	2016 Rates	2017 Rates	2018 Rates
15	Dawn-Parkway Demand Costs ($000's) (5)		5,143	5,694	6,720	9,726
16	Incremental Compressor Fuel Costs ($000's)		1,900	1,797	1,707	1,705
17	Total		7,043	7,491	8,426	11,431
	Foregone Demand Revenue of M12 Dawn-Kirkwall Turnback					
18	Used for PDO Shift ($000's) (7)		580	4,669	5,937	9,993
19	Demand Revenue from Temporarily Available Capacity (line 8 x M12 D-P Rate x 12)		4,563	796	531	-
20	Total		5,143	5,465	6,468	9,993
21	Variance due to Dawn-Parkway Equivalency Differences ($000's) (line 15 - line 20)		-	229	252	(267) (8)

Notes:

(1) W15/16 - Incremental capacity resulting from the Brantford-Kirkwall / Parkway D Project of 433 TJ/d.
W16/17 - Incremental capacity resulting from the Dawn Parkway 2016 System Expansion Project of 443 TJ/d.
W17/18 - Incremental capacity resulting from the 2017 Dawn Parkway Project of 457 TJ/d.

(2) The PDO shift was reflected in Dawn-Parkway excess/(shortfall) beginning W15/16.

(3) The W13/14 forecast filed in Union's 2013 Cost of Service proceeding (EB-2010-0210) included 210 TJ/d of excess Dawn-Parkway capacity. In the EB-2011-0210 Decision, the Board accepted Union's forecast and regulatory treatment.
Union's 2013 cost allocation study allocates Dawn-Parkway demand costs in proportion to distance weighted design day demands. The 2013 allocation resulted in approximately 84% of costs allocated to Union's ex-franchise rate classes and 16% to Union's in-franchise rate classes.

(4) In accordance with the Settlement Framework for Reduction of Parkway Delivery Obligation ("PDO Framework") (EB-2013-0365) effective April 1, 2014, Union had temporarily available Dawn-Parkway capacity which was used to facilitate 146 TJ/d of PDO shift. Parties agreed Union would include the demand and fuel costs associated with the 146 TJ/d of capacity in delivery rates. (PDO Framework, Paragraph B1)

(5) Consistent with the PDO Framework, effective November 1, 2015 the temporarily available capacity was forecast to be used for other purposes leaving Parkway in a delivery shortfall position. Parties agreed that the demand and fuel costs associated with the temporarily available capacity would remain in delivery rates for Union to manage the Parkway delivery shortfall through the acquisition of incremental resources. M12 Dawn to Kirkwall turnback was to be used to first reduce the Parkway delivery shortfall and then to further reduce the remaining PDO. All incremental costs associated with the incremental PDO reduction were recovered by Union in rates (or deferral account due to timing differences). (PDO Framework, Paragraph B2)

(6) As part of the 2017 Dawn-Parkway Project (EB-2015-0200), Union had forecast a surplus of 30,393 GJ/d on the Dawn-Parkway System following the completion of the project. As part of the EB-2015-0200 Settlement Agreement, Union agreed to market the surplus capacity in accordance with the Storage and Transportation Access Rule (“STAR”) and credit the revenues to the project deferral account.

(7) Exhibit J2.5, Attachment 2, line 7.

(8) Dawn-Parkway demand revenue variance is expected to continue through the deferred rebasing period.

UNION GAS LIMITED
Calculation of Foregone Demand Revenue from Turnback Used for PDO Shift

Line No.	Particulars	2015 Rates W14/15	2016 Rates W15/16	2017 Rates W16/17	2018 Rates W17/18
		(a)	(b)	(c)	(d)
	Turnback Used For PDO Shift (TJ/d)				
1	Dawn-Kirkwall turnback - customers without M12 service (1)	-	139	151	242
2	Dawn-Parkway turnback - customers with M12 service (2)	19	19	19	19
	Rate M12 Demand Rates ($/GJ/mo) (3)				
3	Dawn to Kirkwall	2.193	2.421	2.865	3.154
4	Dawn to Parkway	2.604	2.883	3.402	3.716
	Foregone Demand Revenue from M12 Turnback Used for PDO Shift ($000's)				
6	Dawn-Kirkwall (line 2 x line 4 x 12)	-	4,027	5,179	9,165
5	Dawn-Parkway (line 1 x line 3 x 12)	580	643	758	828
7	Total Foregone Revenue (line 5 + line 6)	580	4,669	5,937	9,993

Notes:

(1) Dawn-Kirkwall contract turnback used to create permanent Dawn-Parkway capacity shown at Exhibit J2.5, Attachment 1, line 9 to facilitate PDO Shift.

(2) Exhibit J2.5, Attachment 1, line 11.

(3) Demand rates from Union's annual rates filings: 2015 Rates (EB-2014-0271), 2016 Rates (EB-2015-0116), 2017 Rates (EB-2016-0245), and 2018 Rates (EB-2017-0087).

ENBRIDGE GAS DISTRIBUTION INC. AND UNION GAS LIMITED

Undertaking of Mr. Redford
To Mr. Quinn

REF: Tr.3, p.38

To populate the table on page 24 of FRPO's compendium dated May 3 2018.

	AVERAGE WINTER DAY (TJ/day)[1]								
	RECEIPTS (at Dawn)				RECEIPTS (at Dawn)				
YEAR	UG SYS.[2]	UG DP OBL	UG DP NON OBL	UG DAWN STORAGE[3]	EGD SYS.[4]	EGD DP	EGD STORAGE[5]	DAWN OUTPUT (to D-P SYSTEM)[6]	DAWN OUTPUT (to OTHER)[6]
2013/14	405	238	199	445	736	-	607	2,437	192
2014/15	366	399	155	445	689	-	594	2,325	324
2015/16	229	397	75	304	121	-	472	1,414	184
2016/17	274	410	102	397	479	-	572	1,964	270
2017/18	429	415	188	450	850	183	573	2,656	432

	PEAK WINTER DAY (TJ/day)[7]								
	RECEIPTS (at Dawn)				RECEIPTS (at Dawn)				
YEAR	UG SYS.[2]	UG DP OBL	UG DP NON OBL	UG DAWN STORAGE[3]	EGD SYS.[4]	EGD DP	EGD STORAGE[5]	DAWN OUTPUT (to D-P SYSTEM)[6]	DAWN OUTPUT (to OTHER)[6]
2013/14	190	289	220	1,572	334	-	2,157	4,514	248
2014/15	226	520	188	1,658	328	-	2,169	4,581	509
2015/16	206	467	210	1,767	544	-	2,262	4,922	534
2016/17	344	471	212	1,887	710	-	2,267	5,173	718
2017/18	370	503	278	1,975	738	209	2,302	5,506	869

Notes:

1. Average Winter Day Receipts are calculated by taking total receipts for the winter and dividing by 151 days (except for 2015/2016 which has been divided by 152 days).

2. Union System Receipts represents all gas received at Dawn for System Supply customers. This excludes all gas received at points other than Dawn (i.e. Ojibway, Kirkwall, Parkway, Niagara, Empress or directly in any Union North delivery areas).

3. Dawn Storage represents all withdrawals to meet in-franchise demands (North & South System, North & South DP and North & South T-service).

4. EGD System Receipts represents gas received at Dawn and transported to the Enbridge CDA and Enbridge EDA via transportation services that are contracted by EGD with Union and/or TransCanada. This excludes all gas received at points other than Dawn (i.e. Kirkwall, Parkway, Niagara, Empress or directly in any EGD delivery area).

5. EGD Storage represents gas received by EGD at Dawn from all third party storage service contracts and regulated storage facilities managed by EGD. The natural gas supply at Dawn is transported to the Enbridge CDA and Enbridge EDA via transportation services that are contracted by EGD with Union and/or TransCanada.

6. Dawn Output has been shown to reflect the delivery path out of Dawn. Dawn Output (to D-P System) represents transportation on the Dawn Parkway System for Union and EGD in-franchise customers. Any transportation originating from Dawn to in-franchise customers in Union South or EGD delivery areas contracted through TransCanada is assumed to travel the Dawn Parkway System. Dawn Output (to Other) represents gas sent from Dawn to serve other Union in-franchise areas that do not utilize the Dawn Parkway System (i.e. Windsor, Sarnia, Leamington, etc.).

7. Peak Winter Day represents the Design Day used for Gas Supply planning purposes.

ENBRIDGE GAS DISTRIBUTION INC. AND UNION GAS LIMITED

Undertaking of Mr. Kitchen
To Mr. Quinn

REF: Tr.3, p.84

To provide comments on the Parkway delivery obligation issue

As part of this undertaking, Union agreed to provide:

1. An analysis comparing the treatment of the Parkway Delivery Obligation ("PDO") shift in rates with the cost allocation study impact,
2. The demand allocators and revenue requirement for each Dawn-Parkway system capital pass-through project during Union's 2014-2018 Incentive Regulation Mechanism, and
3. The value of the W17/18 excess Dawn-Parkway System capacity of 106 TJ/d.

1. Comparison of PDO Settlement Treatment in Rates with Cost Allocation Study Impact

Please see Attachment 1 for an analysis showing that the treatment of the PDO in Union's Board-approved rates, as outlined in the EB-2013-0365 PDO Settlement Framework, reasonably reflects the results that would have occurred had the PDO shift been reflected in Union's 2013 Board-approved cost allocation study.

Attachment 1, line 7 estimates an $8.4 million shift in costs to Union South in-franchise rate classes from ex-franchise rate classes when Union's 2013 Board-approved cost allocation study is updated for the W17/18 PDO shift. The W17/18 PDO shift reflects M12 Dawn-Kirkwall turnback of 242 TJ/d and M12 Dawn-Parkway turnback of 81 TJ/d used to facilitate a 280 TJ/d shift in Parkway deliveries to Dawn by in-franchise customers.

Attachment 1, line 22 estimates the revenue impact of the W17/18 PDO shift as outlined in the PDO Settlement Framework using 2013 Board-approved M12 rates. To ensure a comparable analysis of adjusting the 2013 cost allocation study, the 2013 Board-approved M12 rates have been used to calculate the impacts of the W17/18 PDO shift. In Union's annual rate setting process, the PDO impacts are calculated using current approved M12 rates.

Attachment 1, line 23 compares the treatment of the PDO shift in rates with the 2013 cost allocation study impact. The small resulting variance confirms the PDO shift is reasonably reflected in Union's current approved rates.

2. Dawn-Parkway Capital Pass-through Project Demand Allocators and Revenue Requirement

Please see Attachment 2 for the Board-approved 2018 demand allocators and revenue requirement supporting the Dawn-Parkway capital pass-through projects.

3. Value of the W17/18 Excess Dawn-Parkway System Capacity

The value of the 106 TJ/d of excess Dawn-Parkway System capacity Union had forecasted for the W17/18 (Exhibit J2.5, Attachment 1, line 7, column (e)) is approximately $4.7 million. The value associated with the excess capacity is the revenue Union could realize by contracting with customers to sell the capacity at the 2018 M12 Dawn-Parkway demand rate of $3.716 GJ/mo.

Included in the 106 TJ/d of excess capacity forecasted for the W17/18 is 30,393 GJ/d Union forecasted as excess capacity in its 2017 Dawn-Parkway Project (EB-2015-0200). The value associated with the 30,393 GJ/d is approximately $1.4 million of the $4.7 million referenced above. As part of the EB-2015-0200 Settlement Agreement, Union agreed to market the surplus capacity in accordance with the Storage and Transportation Access Rule (“STAR”) and credit the revenues to the project deferral account.

UNION GAS LIMITED
Comparison of PDO Shift in 2013 Cost Allocation Study vs. PDO Settlement Treatment in Rates

Line No.	Particulars	Union South In-Franchise	Union North In-Franchise	Ex-Franchise	Total
		(a)	(b)	(c)	(d) = (a+b+c)
	2013 Cost Allocation Study Impact ($000's)				
	2013 Board-approved Cost Allocation Study				
1	Dawn-Trafalgar Easterly Demand Revenue Requirement (1)	16,290	7,230	121,346	144,866
2	Dawn Station Demand Revenue Requirement (2)	3,396	902	15,727	20,025
3	Total (line 1 + line 2)	19,686	8,133	137,073	164,891
	Updated 2013 Cost Allocation Study to Reflect W17/18 PDO Shift (3)				
4	Dawn-Trafalgar Easterly Demand Revenue Requirement	23,658	7,251	113,957	144,866
5	Dawn Station Demand Revenue Requirement	4,391	909	14,725	20,025
6	Total (line 4 + line 5)	28,050	8,160	128,682	164,891
7	Total 2013 Cost Allocation Study Impact (line 6 - line 3)	8,363	28	(8,391)	-
	PDO Settlement Impact at 2013 Board-approved M12 Rates				
	Inclusion of PDO demand costs in Rates				
8	Customers without M12 service (TJ/d) (4)	200			200
9	All Customers with M12 service excluding TCE Halton Hills (TJ/d) (5)	19			19
10	Total PDO Shift excluding TCE Halton Hills (TJ/d) (line 8 + line 9)	218			218
11	2013 Board-approved M12 Dawn-Parkway demand rate ($/GJ) (6)	2.382			2.382
12	PDO Shift Recovery ($000's) (line 10 x line 11 x 12)	6,236			6,236
	Increase in Billing Contract Demand				
13	TCE Halton Hills (TJ/d) (7)	62			62
14	2013 Board-approved M12 Dawn-Parkway demand rate ($/GJ) (6)	2.382			2.382
15	PDO Shift Recovery ($000's) (line 13 x line 14 x 12)	1,772			1,772
	M12 Turnback				
16	Dawn-Kirkwall turnback - customers without M12 service (TJ/d) (8)			(242)	(242)
17	2013 Board-approved M12 Dawn-Kirkwall demand rate ($/GJ) (9)			2.011	2.011
18	Total Dawn-Kirkwall Foregone Demand Revenue ($000's) (line 16 x line 17 x 12)			(5,843)	(5,843)
19	Dawn-Parkway turnback - customers with M12 service (TJ/d) (10)			(81)	(81)
20	2013 Board-approved M12 Dawn-Parkway demand rate ($/GJ) (6)			2.382	2.382
21	Total Dawn-Parkway Foregone Demand Revenue ($000's) (line 19 x line 20 x 12)			(2,303)	(2,303)
22	Total PDO Settlement Impact at 2013 Rates ($000's) (line 12 + line 15 + line 18 + line 21)	8,008	-	(8,146)	(138)
23	Variance ($000's) (line 22 - line 7)	(356)	(28)	245	(138)

Notes:
(1) EB-2011-0210, Exhibit G3, Tab 2, Schedule 14, Updated.
(2) EB-2011-0210, Exhibit G3, Tab 2, Schedule 12, Updated.
(3) 2013 Board-approved Cost Allocation Study updated to reflect W17/18 PDO shift.
(4) Exhibit J2.5, Attachment 1, line 9, column (e).
(5) Exhibit J2.5, Attachment 1, line 11, column (e).
(6) EB-2011-0210, Rate Order, Appendix A, Page 14, line 2, column (c).
(7) Exhibit J2.5, Attachment 1, line 12, column (e).
(8) Exhibit J2.5, Attachment 2, line 1, column (d).
(9) EB-2011-0210, Rate Order, Appendix A, Page 14, line 1, column (c).
(10) Exhibit J2.5, Attachment 2, line 2, column (d) plus 62 TJ/d related to TCE Halton Hills turnback at line 13, column (d).

UNION GAS LIMITED
Dawn-Trafalgar Easterly Demand and Dawn Station Demand Allocator and Revenue Requirement
Including 2018 Capital Pass-Through Project Allocator Impact and Revenue Requirement

Line No.	Particulars	Union South In-Franchise	Union North In-Franchise	Ex-Franchise	Total
		(a)	(b)	(c)	(d) = (a+b+c)
	2013 Board-approved (EB-2011-0210)				
1	Dawn-Trafalgar Easterly Demand Allocator (1)	3,588	1,592	26,557	31,737
2	Dawn-Trafalgar Easterly Demand Allocator (%)	11.3%	5.0%	83.7%	100%
3	Dawn-Trafalgar Easterly Demand Revenue Requirement ($000's) (2)	16,290	7,230	121,346	144,866
4	Dawn Station Demand Allocator (1)	25,994	6,905	116,184	149,083
5	Dawn Station Demand Allocator (%)	17.4%	4.6%	77.9%	100%
6	Dawn Station Demand Revenue Requirement ($000's) (3)	3,396	902	15,727	20,025
	Parkway Projects (EB-2012-0433 & EB-2013-0074)				
7	Project Distance Weighted Design Day Demands (10^6m^3/d x km) (4)	-	425	2,201	2,626
8	Dawn-Trafalgar Easterly Demand Allocator (line 1 + line 7) (5)	3,588	2,017	28,758	34,363
9	Dawn-Trafalgar Easterly Demand Allocator (%)	10.4%	5.9%	83.7%	100%
10	Dawn-Trafalgar Easterly Demand Revenue Requirement ($000's) (6)	3,052	3,645	34,951	41,648
	2016 Dawn Parkway Expansion (EB-2014-0261)				
11	Project Distance Weighted Design Day Demands (10^6m^3/d x km) (7)	509	285	1,840	2,634
12	Dawn-Trafalgar Easterly Demand Allocator (line 1 + line 11) (8)	4,097	1,878	28,397	34,371
13	Dawn-Trafalgar Easterly Demand Allocator (%)	11.9%	5.5%	82.6%	100%
14	Dawn-Trafalgar Easterly Demand Revenue Requirement ($000's) (9)	5,758	3,980	30,788	40,525
	2017 Dawn-Parkway Expansion (EB-2015-0200)				
15	Project Distance Weighted Design Day Demands (10^6m^3/d x km) (10)	-	-	2,323	2,323
16	Dawn-Trafalgar Easterly Demand Allocator (line 1 + line 15) (11)	3,588	1,592	28,879	34,060
17	Dawn-Trafalgar Easterly Demand Allocator (%)	10.5%	4.7%	84.8%	100%
18	Dawn-Trafalgar Easterly Demand Revenue Requirement ($000's) (12)	2,566	1,139	31,201	34,906
19	Project Design Day Demands Requiring Dawn Compression (10^3m^3/d) (13)	12	3	9,735	9,750
20	Dawn Station Demand Allocator (line 4 + line 19) (14)	26,005	6,908	125,919	158,833
21	Dawn Station Demand Allocator (%)	16.4%	4.3%	79.3%	100%
22	Dawn Station Demand Revenue Requirement ($000's) (15)	3,913	1,039	20,210	25,162

Notes:

(1) EB-2011-0210, Exhibit G3, Tab 5, Schedule 21, Updated, pp. 10-12. Dawn-Trafalgar Easterly Demand costs are allocated using distance weighted Dawn-Parkway design day demands. Dawn Station Demand costs are allocated using Dawn-Parkway easterly design day demands requiring Dawn compression.
(2) EB-2011-0210, Exhibit G3, Tab 2, Schedule 14, Updated.
(3) EB-2011-0210, Exhibit G3, Tab 2, Schedule 12, Updated.
(4) EB-2012-0451/EB-2012-0433/EB-2013-0074, Exhibit I.A3.UGL.FRPO.28, Attachment 1, column (c).
(5) EB-2012-0451/EB-2012-0433/EB-2013-0074, Exhibit I.A3.UGL.FRPO.28, Attachment 1, column (e).
(6) EB-2012-0433, Schedule 12-2, Updated, column (b) and EB-2013-0074, Schedule 10-2, columns (b) and (d).
(7) EB-2014-0261, Exhibit A, Tab 10, Page 5 of 11, Table 10-1, line 5. North Dawn T-service demands included in Ex-franchise.
(8) EB-2014-0261, Exhibit A, Tab 10, Page 5 of 11, Table 10-1, line 6. North Dawn T-service demands included in Ex-franchise.
(9) EB-2014-0261, Settlement Agreement, Appendix 3, Schedule 2, columns (b) and (e).
(10) EB-2015-0200, Exhibit A, Tab 10, Page 6 of 12, Updated, Table 10-1, line 5.
(11) EB-2015-0200, Exhibit A, Tab 10, Page 6 of 12, Updated, Table 10-1, line 6.
(12) EB-2015-0200, Settlement Agreement, Appendix 2, Schedule 2, column (j) plus Dawn-Trafalgar Easterly Demand component of columns (b) and (c).
(13) EB-2015-0200, Exhibit A, Tab 10, Page 7 of 12, Updated, Table 10-2, (line 7 - line 2 + line 5).
(14) EB-2015-0200, Exhibit A, Tab 10, Page 7 of 12, Updated, Table 10-2, line 8.
(15) EB-2015-0200, Settlement Agreement, Appendix 2, Schedule 2, column (f) plus Dawn Station Demand component of columns (b) and (c).

ENBRIDGE GAS DISTRIBUTION INC. AND UNION GAS LIMITED

Undertaking of Mr. Culbert
To Mr. Richler

REF: Tr.3, p.133

To provide the estimated lost revenues for the years 2014-2017, for each of Union and Enbridge, if there was a separate LRAM.

Tables 1 and 2: EGD

	Normalized Actual Average Use (m^3) (1)		DSM Impact per customer (m^3)	
	Rate 1	Rate 6	Rate 1	Rate 6
2013 (2)	2,523	28,946		
2014 (2)	2,520	29,145	(2.5)	(195.7)
2015 (3)	2,497	29,464	(4.9)	(158.9)
2016 (4)	2,401	28,203	(5.0)	(176.8)

(1) Average uses normalized to 2016 HDD for each year
(2) Final DSM results
(3) Audit adjusted DSM results
(4) Pre-audit DSM results

	YoY Change in Average Use (%)		DSM Impact on Average Use (%)	
	Rate 1	Rate 6	Rate 1	Rate 6
2013 - 2014	-0.1%	0.7%	-0.1%	-0.7%
2014 - 2015	-0.9%	1.1%	-0.2%	-0.5%
2015 - 2016	-3.8%	-4.3%	-0.2%	-0.6%
2013 - 2016	-4.8%	-2.6%	-0.5%	-1.8%
2013 - 2016 Average	-1.6%	-0.9%	-0.2%	-0.6%

Tables 3 and 4: Union

Actual NAC (m3)

	Rate M1	Rate M2	Rate 01	Rate 10
2013	2,768	169,422	2,900	168,975
2014 (1)	2,748	167,537	2,923	172,516
2015 (2)	2,676	163,129	2,799	162,078
2016 (3)	2,667	159,933	2,788	159,855

Annual DSM Portion of NAC Change (m3)

Rate M1	Rate M2	Rate 01	Rate 10
(9)	(2,030)	(5)	(1,619)
(8)	(1,471)	(5)	(713)
(8)	(1,414)	(4)	(544)

(1) Final DSM Results
(2) Audit Adjusted DSM Results
(3) Pre-Audit DSM Results

YoY NAC Change (%)

	Rate M1	Rate M2	Rate 01	Rate 10
2013-14	-0.7%	-1.1%	0.8%	2.1%
2014-15	-2.6%	-2.6%	-4.2%	-6.1%
2015-16	-0.3%	-2.0%	-0.4%	-1.4%
2013-16	-3.7%	-5.6%	-3.9%	-5.4%
2013-16 Average	-1.2%	-1.9%	-1.3%	-1.8%

Annual DSM Portion of NAC Change (%)

Rate M1	Rate M2	Rate 01	Rate 10
-0.3%	-1.2%	-0.2%	-1.0%
-0.3%	-0.9%	-0.2%	-0.4%
-0.3%	-0.9%	-0.2%	-0.3%
-0.9%	-2.9%	-0.5%	-1.7%
-0.3%	-1.0%	-0.2%	-0.6%

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

[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

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		Union North - Estimated 2028 (1)				Union South - Estimated 2028 (1)				Enbridge Gas Distribution - Estimated 2028 (1)			
No.	Particulars (cents / m^3)	Rate 01		Rate 10		Rate M1		Rate M2		Rate 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 m^3	17.3281	First 1,000 m^3	11.7212	First 100 m^3	10.7860	First 1,000 m^3	7.2092	First 30 m^3	17.3730	First 500 m^3	13.7064
4	(declining block structure)	Next 200 m^3	16.9457	Next 9,000 m^3	9.7200	Next 150 m^3	10.3210	Next 6,000 m^3	7.0848	Next 55 m^3	16.3392	Next 1,050 m^3	10.7970
5		Next 200 m^3	16.3505	Next 20,000 m^3	8.3985	All over 250 m^3	9.1199	Next 13,000 m^3	6.3509	Next 85 m^3	15.5295	Next 4,500 m^3	8.7596
6		Next 500 m^3	15.8040	Next 70,000 m^3	7.6860			All over 20,000 m^3	5.9338	Over 170 m^3	14.9261	Next 7,000 m^3	7.4506
7		Over 1,000 m^3	15.3526	Over 100,000 m^3	4.9865							Next 15,250 m^3	6.8690
												Over 28,300 m^3	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		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	2.6249	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	
	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

			Estimated 2019 Rates				Estimated 2028 Rates		
Line No.	Particulars	Approved 01-Apr-18 Total Bill ($) (1)	2019 Total Bill ($) (2)	2019 vs 2018 Bill Impact ($)	Annual Increase from 2018 (%)	2028 Total Bill ($) (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.

ENBRIDGE GAS DISTRIBUTION INC. AND UNION GAS LIMITED

Undertaking of Mr. Culbert
To Ms. Anderson

For 2012 to 2016 provide a comparison of an inflation factor using just GDP IPI FDD with an inflation factor using both GDP IPI FDD and AWE (70/30 Weighted) (for the Electric Utilities).

	GDP IPI FDD	70% GDP IPI FDD and 30% AWE
1991		
1992	1.9%	2.5%
1993	1.8%	2.0%
1994	1.7%	2.0%
1995	1.2%	1.1%
1996	1.2%	1.5%
1997	1.5%	1.7%
1998	1.5%	1.4%
1999	1.4%	1.5%
2000	2.6%	2.5%
2001	2.0%	1.2%
2002	2.4%	2.3%
2003	1.6%	1.9%
2004	1.8%	2.1%
2005	2.1%	2.6%
2006	2.3%	2.1%
2007	2.5%	2.9%
2008	2.6%	2.5%
2009	1.1%	1.2%
2010	1.1%	1.9%
2011	2.4%	2.1%
2012	1.7%	1.6%
2013	1.7%	1.7%
2014	2.3%	2.2%
2015	1.6%	1.9%
2016	1.2%	1.2%
2017	1.4%	NA
Averages		
2012-2016	1.7%	1.7%
2007-2016	1.8%	1.9%