ENBRIDGE

Rakesh Torul
Technical Manager
Regulatory Applications
Regulatory Affairs

tel 416-495-5499
EGIRegulatoryProceedings@enbridge.com

Enbridge Gas Inc.
500 Consumers Road
North York, Ontario M2J 1P8
Canada

VIA EMAIL, RESS and COURIER

February 21, 2020

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

Re: EB-2019-0194 Enbridge Gas Inc. ("Enbridge Gas")
2020 Rates – Interrogatory Responses & Evidence Correction

In accordance with the Decision on Settlement Proposal and Interim Rate Order dated December 5, 2019 and Procedural Order No. 2 dated January 9, 2020, enclosed please find interrogatory responses from Enbridge Gas in the above noted proceeding.

As part of the response to the interrogatories, live excel documents have been provided to the following:

- Exhibit I.FRPO.12, Attachment 1
- Exhibit I.Kitchener.1, Attachment 2

Further to the submission made by Enbridge Gas on January 15, 2020, also enclosed is a correction to Exhibit B-3-1. The table below illustrates the corrections.

Exhibit	**Original**	**Correction**
Exhibit B-3-1	Paragraph 37(ii) - "Within the EGD rate zone, 331,480 active customers…" Paragraph 53 "eBilling would be close to $45 million annually." Paragraph 53 "the current combined cost of paper and digital bill delivery is approximately $28 million annually."	Paragraph 37(ii) - "Within the EGD rate zone, 358,384 active customers…" Paragraph 53 "eBilling would be close to $42.5 million annually." Paragraph 53 "the current combined cost of paper and digital bill delivery is approximately $21 million annually."

Please contact the undersigned if you have any questions.

Yours truly,

(Original Signed)

Rakesh Torul
Technical Manager,
Regulatory Applications

cc: David Stevens, Aird and Berlis LLP
EB-2019-0194 Intervenors

ENBRIDGE GAS INC.

Answer to Interrogatory from OEB Staff ("STAFF")

Interrogatory

Reference:

Exhibit B, Tab 1, Schedule 1, Appendix C: Cost Allocation Study, Table 1, p. 5

Question:

Enbridge Gas has provided a table that shows a summary of the results of the 2019 cost allocation study directive using OEB-approved cost allocation methodologies and the proposed cost allocation methodologies provided in response to the OEB's directive in the MAADs Decision (EB-2017-0306/0307). The summary shows the revenue sufficiency/deficiency across the various rate classes.

a) Please clarify if the column "Current Approved Revenue" represents the rate year 2019 or 2020.

b) Please confirm if the amounts of the revenue sufficiency/deficiency under the proposed methodology includes the amounts recovered as capital pass-through adjustments.

c) Please provide a revised table that includes an additional column that shows the amounts recovered as capital pass-through adjustments.

Response

a) The current approved revenue is based on 2019.

b) Confirmed.

c) Please see Attachment 1.

UNION RATE ZONES

Summary of 2019 Cost Allocation Study Directive with Capital Pass-through Projects Recovery

Line No.	Particulars ($000's)	Current Approved Revenue: Capital Pass-Through Projects	Current Approved Revenue: All Other Revenue	Current Approved Revenue: Total	Board-Approved Methodology: Revenue Requirement	Board-Approved Methodology: Revenue (Deficiency)/ Sufficiency	Impact of Cost Study Proposals	Proposed Methodology: Revenue Requirement	Proposed Methodology: Revenue (Deficiency)/ Sufficiency
		(a)	(b)	(c) = (a+b)	(d)	(e) = (c-d)	(f)	(g) = (d+f)	(h) = (c-g)
	Union North								
1	Rate 01	2,352	195,609	197,961	199,893	(1,932)	1,064	200,957	(2,996)
2	Rate 10	2,036	25,376	27,412	31,809	(4,396)	331	32,140	(4,727)
3	Rate 20	3,351	24,170	27,521	27,410	111	170	27,581	(60)
4	Rate 25	132	2,318	2,450	4,081	(1,631)	5	4,085	(1,635)
5	Rate 100	1,299	8,789	10,089	11,244	(1,156)	4	11,248	(1,160)
	Union South								
6	Rate M1	(3,643)	458,952	455,310	458,618	(3,308)	451	459,069	(3,760)
7	Rate M2	2,136	64,932	67,068	70,841	(3,773)	154	70,995	(3,927)
8	Rate M4	3,204	25,471	28,675	34,166	(5,491)	3,414	37,580	(8,905)
9	Rate M5	(21)	2,507	2,486	2,623	(136)	17	2,639	(153)
10	Rate M7	1,058	11,392	12,450	15,366	(2,916)	933	16,299	(3,849)
11	Rate M9	123	1,035	1,158	1,231	(74)	(85)	1,146	11
12	Rate M10	3	17	20	18	2	(1)	17	3
13	Rate T1	1,035	10,794	11,829	12,236	(407)	418	12,654	(825)
14	Rate T2	10,671	56,476	67,147	64,891	2,255	(6,381)	58,511	8,636
15	Rate T3	824	5,903	6,728	6,494	234	(487)	6,007	720
	Ex-Franchise								
16	Rate M12/C1 - Dawn-Parkway	95,751	156,931	252,682	228,089	24,593	7,677	235,767	16,916
17	Rate M13	(5)	334	328	426	(98)	(0)	426	(98)
18	Rate M16	353	567	920	1,664	(744)	(738)	927	(6)
19	Rate C1 - Other	922	29,871	30,793	33,020	(2,228)	(6,948)	26,072	4,720
20	Commodity / Admin	(88)	9,016	8,928	6,956	1,971	-	6,956	1,971
21	Gas Supply and Transportation	-	593,230	593,230	593,230	-	-	593,230	-
22	Total	121,492	1,683,692	1,805,184	1,804,307	880	-	1,804,307	880

ENBRIDGE GAS INC.

Answer to Interrogatory from
OEB Staff ("STAFF")

Interrogatory

Reference:

Exhibit B, Tab 1, Schedule 1, Appendix C: Cost Allocation Study, Table 1, pp. 18-21

Question:

Enbridge Gas has allocated the compressor costs at Parkway in proportion to the easterly design day demands requiring compression at Parkway. This allocation methodology recognizes that compressor equipment is used on design day to move volumes to markets east of Parkway. However, compression costs of the Dawn-Parkway System (Dawn, Lobo and Bright) are allocated on a distance weighted methodology. The evidence notes that a distance weighted allocation is appropriate for compression costs at Dawn, as additional compression is required the further gas is required to travel on the Dawn-Parkway system.

Please explain why compression costs at Parkway are allocated in proportion to easterly design day demand and does not take into account distance travelled similar to compression costs at Dawn.

Response

The Board-approved allocation methodology of the Dawn-Parkway transmission system is based on the distance weighted Dawn-Parkway design day demands. The cost allocation methodology recognizes that a rate class's use of the Dawn-Parkway system varies based on the design day demands and the distance those design day demands are required to be transported easterly from Dawn to Parkway.

The proposed allocation methodology for Parkway Station compression costs does not take into account the distance travelled on the Dawn-Parkway transmission system as the compression at the Parkway Station is required to transport gas to markets east of Parkway using downstream pipelines on design day. The compression costs of Dawn, Lobo, and Bright do take into consideration the distance travelled on the Dawn-Parkway transmission system as these compressors are required on design day to transport gas easterly along the Dawn-Parkway transmission system.

ENBRIDGE GAS INC.

Answer to Interrogatory from
OEB Staff ("STAFF")

Interrogatory

Reference:

Exhibit B, Tab 1, Schedule 1, Appendix C: Cost Allocation Study, Table 1, pp. 26-28

Question:

In the MAADs Decision (EB-2017-0306/0307), Enbridge Gas was directed to include a proposal to address TransCanada's Rate C1 Dawn to Dawn-TCPL service. In this study, Enbridge Gas has not updated the Rate C1 Dawn to Dawn-TCPL firm demand rate to reflect updated costs from the 2019 cost allocation study. The Rate C1 Dawn to Dawn-TCPL rate design was approved by the OEB in 2010 as part of Union Gas's Dawn to Dawn-TCPL Firm Rate proceeding (EB-2010-0201). As part of Union Gas's OEB-approved cost allocation study, the revenue requirement of $0.5 million related to the Dawn to Dawn-TCPL facilities was included in setting the Rate C1 Dawn to Dawn-TCPL firm demand rate, which represented the third year of the five year depreciation period. During Union Gas's 2014-2018 IRM term, there was no further adjustment made to the revenue requirement for the service even though the assets had fully depreciated in 2015. As part of the MAADs proceeding, TransCanada (TC) Energy submitted that the revenue requirement of the Rate C1 Dawn to Dawn-TCPL could be reduced without any cost consequences to other shippers. Enbridge Gas does not agree with this view and has noted that a reduction to the Rate C1 Dawn to Dawn-TCPL demand rate would impact other shippers, as any rate adjustments made during the deferred rebasing period should be made on a revenue neutral basis for the utility.

a) In the MAADs proceeding, Enbridge Gas requested certain base rate adjustments (deferred tax drawdown, EGD customer information system costs, pension costs and site restoration costs). Please explain why Enbridge Gas did not request a base rate adjustment to the Rate C1 Dawn to Dawn-TCPL firm demand rate considering that the asset had fully depreciated in 2015.

b) Why is Enbridge Gas proposing no changes to the Rate C1 Dawn to Dawn-TCPL firm demand rate considering that the OEB in the MAADs Decision required

Enbridge Gas to present a proposal to address TransCanada's Rate C1 Dawn to Dawn-TCPL service?

c) Why does Enbridge Gas believe that a marginal reduction of $0.5 million (as compared to the total revenue requirement of Enbridge Gas) should be made on a revenue neutral basis?

<u>Response</u>

a) Enbridge Gas did not request a base rate adjustment for the Rate C1 Dawn to Dawn-TCPL firm demand rate as part of the MAADs proceeding because Enbridge Gas had requested to defer rebasing as part of that proceeding. During a deferred rebasing period, rates are decoupled from costs and the Company earns revenue consistent with the approved rate setting mechanism.

   The base rate adjustments proposed by Enbridge Gas in the MAADs proceeding related to discrete adjustments that were the subject of settlements from prior proceedings and expired at the end of 2018.

b) As described in evidence at pages 27-28, paragraphs 60-61, a reduction to the Rate C1 Dawn to Dawn-TCPL demand rate would impact other shippers, as any rate adjustment made during the deferred rebasing period should be made on a revenue neutral basis to maintain the utility's revenue derived through the approved rate setting mechanism. Even though the Dawn to Dawn-TCPL facilities are fully depreciated, rates are decoupled from costs during the deferred rebasing period and calculated based on the approved rate setting mechanism. This is consistent for all services and rate classes.

   There may also be impacts on the incremental capital module (ICM) if adjustments were made to costs for one service or rate class without maintaining revenue neutrality for the Company. For example, a factor in the calculation of the ICM capital threshold is the depreciation expense included in base rates. The ICM capital threshold establishes the minimum capital expenditures the utility must fund through base rates calculated through the approved rate setting mechanism. If a rate adjustment was made without maintaining revenue neutrality, the ICM capital threshold value would be overstated and disconnected from the amount of capital that can be funded through rates.

   Given the potential impact to other rate classes and the interdependencies of the approved rate setting mechanism and ICM, Enbridge Gas finds it difficult to recommend changes based on one service or cost item.

c) Enbridge Gas's position is that the utility's revenue should and will be earned consistent with the approved rate setting mechanism established by the Board in the MAADs Decision during the deferred rebasing period, as described in parts a) and b). Enbridge Gas also recognizes that cost allocation is a zero-sum exercise. It is inconsistent to adjust the allocated revenue requirement of one rate class to reflect a decrease in costs and not reflect other cost changes (increases) to other rate classes, which in aggregate would sum to zero.

ENBRIDGE GAS INC.

Answer to Interrogatory from
OEB Staff ("STAFF")

Interrogatory

Reference:

Exhibit B, Tab 1, Schedule 1, Appendix C: Cost Allocation Study, Table 1, pp. 29-30

Question:

Enbridge Gas has proposed to implement the cost allocation methodology changes approved as a result of the cost allocation study directive with its next rebasing proceeding. Enbridge Gas notes that should rates be adjusted based on the 2019 cost allocation study in 2021 and again in 2024 at rebasing, customers would be subject to unpredictable rate changes within a short three-year time period, with some rate classes experiencing a rate increase and others experiencing a rate decrease. In the event that the OEB determines that Enbridge Gas's cost allocation proposals should be implemented prior to its next rebasing application, then Enbridge Gas has proposed that this should be done as part of the 2021 rate application. This will allow time for all appropriate adjustments to be calculated, explained and approved.

a) In the MAADs Decision, the OEB expressed concern about cost allocation issues with respect to the impact of Union Gas's capital pass-through projects during the 2014-2018 IRM term. Accordingly, Enbridge Gas was required to provide a cost allocation update for the Union Gas rate zone as part of the 2020 rate proceeding. Is Enbridge Gas of the opinion that the OEB required a cost allocation update for information purposes only? Please provide a detailed response.

b) Please explain why the cost allocation changes cannot be implemented in this application considering that there is an interrogatory process in this application for the cost allocation evidence and sufficient time to implement the changes in this application.

c) Please provide rate impacts for the rate classes 01, 10, M1 and M2 if the cost allocation changes are implemented in this application. Please include only the impact of cost allocation in the rate impact calculation.

Response

a) Enbridge Gas interprets that the MAADs Decision required the Company to file a cost allocation study in 2019 for the legacy Union Gas service area for consideration in the 2020 Rates proceeding. It is not Enbridge Gas's interpretation that the Board required the Company to complete a full cost of service update to rates. The cost allocation study does, however, provide the OEB and other interested parties with cost allocation information that was not available at the time of the MAADs Decision.

b) Enbridge Gas is not recommending changes to rates as a result of the cost allocation study directive because rates are set through an approved price cap rate setting mechanism. The Company anticipates there will be additional changes to rates at rebasing in 2024 when Enbridge Gas introduces rate harmonization, integration of the cost allocation studies of the combined utilities and the pass-through of synergy cost savings into rates. Should rates be adjusted as part of this proceeding and again in 2024, customers would be subject to unpredictable rate changes within a short 3-year time period with some rate classes experiencing a rate increase and others experiencing a rate decrease. The Board-approved rate setting mechanism provides more reliable and predictable rates during the deferred rebasing period.

   Should the Board direct an update to rates as a result of the cost allocation study directive, Enbridge Gas recommends that rate changes be implemented no earlier than with 2021 Rates. This timing would allow the process of a final rate order in this application and time for the Company to give customers advance notice of potentially material rate changes, as illustrated in part c). Enbridge Gas has provided the steps, estimated timeline and considerations required to implement rate changes from the cost allocation study directive in rates at Exhibit I.IGUA.6.

   As described in more detail at Exhibit I.IGUA.6, if required, implementation with 2021 Rates allows Enbridge Gas the time required to conduct a more thorough review of rate design considerations and rate class impacts. Implementation of cost allocation study results by rate class without consideration of rate design factors may result in unintended impacts that cannot be predicted without a complete rate design review similar to what is completed as part of a cost of service proceeding. A description of other rate design considerations is provided at Exhibit I.TCPL.1 part d).

c) Enbridge Gas does not believe it is appropriate to implement the cost allocation changes without consideration to rate design. While the allocated cost of service produced by the cost allocation study is the primary driver of setting rates there are other factors that must be considered prior to proposing final rates. Please see part b).

For the purposes of this response, Enbridge Gas has prepared estimated bill impacts for all in-franchise customers in the Union rate zone including the impacts of the cost allocation proposals, as provided at Attachment 1. The estimated bill impacts excluding the cost allocation proposals are provided at Attachment 2. The calculation of the unit rates is provided at Attachment 3. The volume assumptions used to calculate the typical bill impacts are provided at Attachment 4.

To derive the estimated bill impacts, Enbridge Gas prepared unit rates, assuming the cost allocation variances identified in Exhibit B, Tab 1, Schedule 1, Appendix C, Table 1, column (c) and column (f)[1] were adjusted in rates. The assumptions Enbridge Gas made to derive the unit rates, provided at Attachment 3, used in the bill impact calculations are listed below:

- The level of the monthly customer charge for general service rate classes was not adjusted. Cost allocation variances associated with the general service monthly customer charge were recovered in volumetric delivery blocks.
- A common rate increase was used for each distribution rate component within the same rate class.
- Common unit rates were maintained for certain rates based on Board-approved rate design (i.e. Rate T1/T2/T3 storage charges).
- All rate classes are deemed to recover total allocated costs less allocated S&T margin without any rate design adjustments between rate classes.

[1] Enbridge Gas notes that in pre-filed evidence at Exhibit B, Tab 1, Schedule 1, Appendix C, Table 1 and at Exhibit B, Tab 1, Appendix C, Working Papers, Schedule 4, p.1 the Rate 25 and Rate 100 lines are inverted.

UNION RATE ZONES
Union North In-Franchise
Calculation of 2020 Sales Service and Direct Purchase Bill Impacts for Typical Small and Large Customers

		Approved - EB-2019-0194 (1)		Updated for Cost Study (with proposals)			Bill Impact	
Line No.	Particulars	Total Bill ($)	Unit Rate (cents/m^3)	Total Bill ($)	Unit Rate (cents/m^3)	Total Bill Change ($)	Including Federal Carbon Charge (%)	Excluding Federal Carbon Charge (%)
		(a)	(b)	(c)	(d)	(e) = (c - a)	(f) = (e / a)	(g)
	Small Rate 01							
1	Delivery Charges	475	21.6105	489	22.2245	13.51	2.8%	2.8%
2	Federal Carbon Charge	86	3.9100	86	3.9100	-	0.0%	0.0%
3	Gas Supply Charges (2)	411	18.6827	408	18.5264	(3.44)	-0.8%	-0.8%
4	Total Bill	972	44.2027	983	44.6605	10.07	1.0%	1.1%
5	Sales Service Impact					10.07	1.0%	1.1%
6	Bundled-T (Direct Purchase) Impact					10.07	1.5%	1.7%
	Small Rate 10							
7	Delivery Charges	5,112	8.5204	6,106	10.1769	994	19.4%	19.4%
8	Federal Carbon Charge	2,346	3.9100	2,346	3.9100	-	0.0%	0.0%
9	Gas Supply Charges (2)	10,204	17.0074	10,272	17.1194	67	0.7%	0.7%
10	Total Bill	17,663	29.4378	18,724	31.2063	1,061	6.0%	6.9%
11	Sales Service Impact					1,061	6.0%	6.9%
12	Bundled-T (Direct Purchase) Impact					1,087	10.1%	13.0%
	Large Rate 10							
13	Delivery Charges	16,685	6.6740	20,403	8.1614	3,718	22.3%	22.3%
14	Federal Carbon Charge	9,775	3.9100	9,775	3.9100	-	0.0%	0.0%
15	Gas Supply Charges (2)	42,519	17.0074	42,799	17.1194	280	0.7%	0.7%
16	Total Bill	68,979	27.5914	72,977	29.1908	3,998	5.8%	6.8%
17	Sales Service Impact					3,998	5.8%	6.8%
18	Bundled-T (Direct Purchase) Impact					4,105	10.3%	13.6%
	Small Rate 20							
19	Delivery Charges	88,161	2.9387	85,455	2.8485	(2,706)	-3.1%	-3.1%
20	Federal Carbon Charge	117,300	3.9100	117,300	3.9100	-	0.0%	0.0%
21	Gas Supply Charges (2)	406,896	13.5632	437,802	14.5934	30,906	7.6%	7.6%
22	Total Bill	612,357	20.4119	640,557	21.3519	28,200	4.6%	5.7%
23	Sales Service Impact					28,200	4.6%	5.7%
24	Bundled-T (Direct Purchase) Impact					29,475	10.7%	18.8%
	Large Rate 20							
25	Delivery Charges	344,338	2.2956	333,934	2.2262	(10,404)	-3.0%	-3.0%
26	Federal Carbon Charge	586,500	3.9100	586,500	3.9100	-	0.0%	0.0%
27	Gas Supply Charges (2)	1,985,265	13.2351	2,116,808	14.1121	131,543	6.6%	6.6%
28	Total Bill	2,916,103	19.4407	3,037,242	20.2483	121,139	4.2%	5.2%
29	Sales Service Impact					121,139	4.2%	5.2%
30	Bundled-T (Direct Purchase) Impact					127,514	10.4%	19.9%
	Average Rate 25							
31	Delivery Charges	72,987	3.2082	123,939	5.4478	50,952	69.8%	69.8%
32	Federal Carbon Charge	88,953	3.9100	88,953	3.9100	-	0.0%	0.0%
33	Gas Supply Charges (2)	280,146	12.3141	281,631	12.3794	1,486	0.5%	0.5%
34	Total Bill	442,085	19.4323	494,522	21.7372	52,437	11.9%	14.8%
35	Sales Service Impact					52,437	11.9%	14.8%
36	T-Service (Direct Purchase) Impact					50,952	31.5%	69.8%
	Small Rate 100							
37	Delivery Charges	317,202	1.1748	354,479	1.3129	37,277	11.8%	11.8%
38	Federal Carbon Charge	1,055,700	3.9100	1,055,700	3.9100	-	0.0%	0.0%
39	Gas Supply Charges (2)	4,605,591	17.0577	4,594,116	17.0152	(11,475)	-0.2%	-0.2%
40	Total Bill	5,978,493	22.1426	6,004,294	22.2381	25,802	0.4%	0.5%
41	Sales Service Impact					25,802	0.4%	0.5%
42	T-Service (Direct Purchase) Impact					37,277	2.7%	11.8%
	Large Rate 100							
43	Delivery Charges	2,591,790	1.0799	2,894,108	1.2059	302,318	11.7%	11.7%
44	Federal Carbon Charge	9,384,000	3.9100	9,384,000	3.9100	-	0.0%	0.0%
45	Gas Supply Charges (2)	40,330,491	16.8044	40,228,491	16.7619	(102,000)	-0.3%	-0.3%
46	Total Bill	52,306,281	21.7943	52,506,599	21.8777	200,318	0.4%	0.5%
47	Sales Service Impact					200,318	0.4%	0.5%
48	T-Service (Direct Purchase) Impact					302,318	2.5%	11.7%

Notes:
(1) Reflects approved rates per EB-2019-0194, Exhibit D, Tab 2, Rate Order, Appendix A.
(2) Gas Supply charges based on Union North East Zone.

UNION RATE ZONES
Union South In-Franchise
Calculation of 2020 Sales Service and Direct Purchase Bill Impacts for Typical Small and Large Customers

		Approved - EB-2019-0194 (1)		Updated for Cost Study (with proposals)			Bill Impact	
Line No.	Particulars	Total Bill ($)	Unit Rate (cents/m^3)	Total Bill ($)	Unit Rate (cents/m^3)	Total Bill Change ($)	Including Federal Carbon Charge (%)	Excluding Federal Carbon Charge (%)
		(a)	(b)	(c)	(d)	(e) = (c - a)	(f) = (e / a)	(g)
	Small Rate M1							
1	Delivery Charges	399	18.1218	402	18.2532	2.89	0.7%	0.7%
2	Federal Carbon Charge	86	3.9100	86	3.9100	-	0.0%	0.0%
3	Gas Supply Charges	249	11.3023	248	11.2595	(0.94)	-0.4%	-0.4%
4	Total Bill	733	33.3336	735	33.4223	1.95	0.3%	0.3%
5	Sales Service Impact					1.95	0.3%	0.3%
6	Direct Purchase Impact					2.89	0.6%	0.7%
	Small Rate M2							
7	Delivery Charges	4,111	6.8519	4,407	7.3445	296	7.2%	7.2%
8	Federal Carbon Charge	2,346	3.9100	2,346	3.9100	-	0.0%	0.0%
9	Gas Supply Charges	6,782	11.3025	6,756	11.2600	(26)	-0.4%	-0.4%
10	Total Bill	13,239	22.0644	13,509	22.5145	270	2.0%	2.5%
11	Sales Service Impact					270	2.0%	2.5%
12	Direct Purchase Impact					296	4.6%	7.2%
	Large Rate M2							
13	Delivery Charges	13,718	5.4872	14,885	5.9541	1,167	8.5%	8.5%
14	Federal Carbon Charge	9,775	3.9100	9,775	3.9100	-	0.0%	0.0%
15	Gas Supply Charges	28,256	11.3025	28,150	11.2600	(106)	-0.4%	-0.4%
16	Total Bill	51,749	20.6997	52,810	21.1241	1,061	2.1%	2.5%
17	Sales Service Impact					1,061	2.1%	2.5%
18	Direct Purchase Impact					1,167	5.0%	8.5%
	Small Rate M4							
19	Delivery Charges	48,933	5.5923	63,650	7.2743	14,717	30.1%	30.1%
20	Federal Carbon Charge	34,213	3.9100	34,213	3.9100	-	0.0%	0.0%
21	Gas Supply Charges	98,897	11.3025	98,525	11.2600	(372)	-0.4%	-0.4%
22	Total Bill	182,042	20.8048	196,387	22.4443	14,345	7.9%	9.7%
23	Sales Service Impact					14,345	7.9%	9.7%
24	Direct Purchase Impact					14,717	17.7%	30.1%
	Large Rate M4							
25	Delivery Charges	370,929	3.0911	481,425	4.0119	110,496	29.8%	29.8%
26	Federal Carbon Charge	469,200	3.9100	469,200	3.9100	-	0.0%	0.0%
27	Gas Supply Charges	1,356,300	11.3025	1,351,200	11.2600	(5,100)	-0.4%	-0.4%
28	Total Bill	2,196,429	18.3036	2,301,825	19.1819	105,396	4.8%	6.1%
29	Sales Service Impact					105,396	4.8%	6.1%
30	Direct Purchase Impact					110,496	13.2%	29.8%
	Small Rate M5							
31	Delivery Charges	32,447	3.9330	34,490	4.1807	2,043	6.3%	6.3%
32	Federal Carbon Charge	32,258	3.9100	32,258	3.9100	-	0.0%	0.0%
33	Gas Supply Charges	93,246	11.3025	92,895	11.2600	(351)	-0.4%	-0.4%
34	Total Bill	157,950	19.1455	159,643	19.3507	1,693	1.1%	1.3%
35	Sales Service Impact					1,693	1.1%	1.3%
36	Direct Purchase Impact					2,043	3.2%	6.3%
	Large Rate M5							
37	Delivery Charges	182,217	2.8033	193,437	2.9760	11,220	6.2%	6.2%
38	Federal Carbon Charge	254,150	3.9100	254,150	3.9100	-	0.0%	0.0%
39	Gas Supply Charges	734,663	11.3025	731,900	11.2600	(2,763)	-0.4%	-0.4%
40	Total Bill	1,171,030	18.0158	1,179,487	18.1460	8,457	0.7%	0.9%
41	Sales Service Impact					8,457	0.7%	0.9%
42	Direct Purchase Impact					11,220	2.6%	6.2%
	Small Rate M7							
43	Delivery Charges	760,766	2.1132	998,550	2.7737	237,784	31.3%	31.3%
44	Federal Carbon Charge	1,407,600	3.9100	1,407,600	3.9100	-	0.0%	0.0%
45	Gas Supply Charges	4,068,900	11.3025	4,053,600	11.2600	(15,300)	-0.4%	-0.4%
46	Total Bill	6,237,266	17.3257	6,459,750	17.9437	222,484	3.6%	4.6%
47	Sales Service Impact					222,484	3.6%	4.6%
48	Direct Purchase Impact					237,784	11.0%	31.3%
	Large Rate M7							
49	Delivery Charges	3,067,592	5.8992	4,021,438	7.7335	953,845	31.1%	31.1%
50	Federal Carbon Charge	2,033,200	3.9100	2,033,200	3.9100	-	0.0%	0.0%
51	Gas Supply Charges	5,877,300	11.3025	5,855,200	11.2600	(22,100)	-0.4%	-0.4%
52	Total Bill	10,978,092	21.1117	11,909,838	22.9035	931,745	8.5%	10.4%
53	Sales Service Impact					931,745	8.5%	10.4%
54	Direct Purchase Impact					953,845	18.7%	31.1%

Notes:
(1) Reflects approved rates per EB-2019-0194, Exhibit D, Tab 2, Rate Order, Appendix A.

UNION RATE ZONES
Union South In-Franchise
Calculation of 2020 Sales Service and Direct Purchase Bill Impacts for Typical Small and Large Customers

		Approved - EB-2019-0194 (1)		Updated for Cost Study (with proposals)			Bill Impact	
Line No.	Particulars	Total Bill ($)	Unit Rate (cents/m³)	Total Bill ($)	Unit Rate (cents/m³)	Total Bill Change ($)	Including Federal Carbon Charge (%)	Excluding Federal Carbon Charge (%)
		(a)	(b)	(c)	(d)	(e) = (c - a)	(f) = (e / a)	(g)
	Small Rate M9							
1	Delivery Charges	173,981	2.5033	172,327	2.4795	(1,654)		-1.0%
2	Gas Supply Charges	785,524	11.3025	782,570	11.2600	(2,954)		-0.4%
3	Total Bill	959,505	13.8058	954,897	13.7395	(4,608)		-0.5%
4	Sales Service Impact					(4,608)		-0.5%
5	Direct Purchase Impact					(1,654)		-1.0%
	Large Rate M9							
6	Delivery Charges	517,516	2.5648	512,596	2.5404	(4,920)		-1.0%
7	Gas Supply Charges	2,280,618	11.3025	2,272,043	11.2600	(8,576)		-0.4%
8	Total Bill	2,798,135	13.8673	2,784,639	13.8004	(13,496)		-0.5%
9	Sales Service Impact					(13,496)		-0.5%
10	Direct Purchase Impact					(4,920)		-1.0%
	Average Rate M10							
11	Delivery Charges	7,208	7.6274	6,197	6.5577	(1,011)		-14.0%
12	Gas Supply Charges	10,681	11.3025	10,641	11.2600	(40)		-0.4%
13	Total Bill	17,889	18.9299	16,838	17.8177	(1,051)		-5.9%
14	Sales Service Impact					(1,051)		-5.9%
15	Direct Purchase Impact					(1,011)		-14.0%
	Small Rate T1							
16	Delivery Charges	161,004	2.1362	180,447	2.3942	19,444	12.1%	12.1%
17	Federal Carbon Charge	294,697	3.9100	294,697	3.9100	-	0.0%	0.0%
18	Gas Supply Charges	851,869	11.3025	848,666	11.2600	(3,203)	-0.4%	-0.4%
19	Total Bill	1,307,570	17.3487	1,323,810	17.5642	16,241	1.2%	1.6%
20	Sales Service Impact					16,241	1.2%	1.6%
21	Direct Purchase Impact					19,444	4.3%	12.1%
	Average Rate T1							
22	Delivery Charges	249,405	2.1564	279,398	2.4157	29,994	12.0%	12.0%
23	Federal Carbon Charge	452,228	3.9100	452,228	3.9100	-	0.0%	0.0%
24	Gas Supply Charges	1,307,240	11.3025	1,302,325	11.2600	(4,916)	-0.4%	-0.4%
25	Total Bill	2,008,873	17.3689	2,033,951	17.5857	25,078	1.2%	1.6%
26	Sales Service Impact					25,078	1.2%	1.6%
27	Direct Purchase Impact					29,994	4.3%	12.0%
	Large Rate T1							
28	Delivery Charges	559,233	2.1825	626,142	2.4436	66,909	12.0%	12.0%
29	Federal Carbon Charge	1,001,902	3.9100	1,001,902	3.9100	-	0.0%	0.0%
30	Gas Supply Charges	2,896,162	11.3025	2,885,271	11.2600	(10,890)	-0.4%	-0.4%
31	Total Bill	4,457,296	17.3950	4,513,315	17.6136	56,019	1.3%	1.6%
32	Sales Service Impact					56,019	1.3%	1.6%
33	Direct Purchase Impact					66,909	4.3%	12.0%
	Small Rate T2							
34	Delivery Charges	731,795	1.2350	652,612	1.1013	(79,183)	-10.8%	-10.8%
35	Federal Carbon Charge	2,316,910	3.9100	2,316,910	3.9100	-	0.0%	0.0%
36	Gas Supply Charges	6,697,409	11.3025	6,672,226	11.2600	(25,184)	-0.4%	-0.4%
37	Total Bill	9,746,114	16.4475	9,641,748	16.2713	(104,366)	-1.1%	-1.4%
38	Sales Service Impact					(104,366)	-1.1%	-1.4%
39	Direct Purchase Impact					(79,183)	-2.6%	-10.8%
	Average Rate T2							
40	Delivery Charges	1,766,761	0.8933	1,578,503	0.7981	(188,258)	-10.7%	-10.7%
41	Federal Carbon Charge	7,733,583	3.9100	7,733,583	3.9100	-	0.0%	0.0%
42	Gas Supply Charges	22,355,198	11.3025	22,271,137	11.2600	(84,061)	-0.4%	-0.4%
43	Total Bill	31,855,542	16.1058	31,583,223	15.9681	(272,319)	-0.9%	-1.1%
44	Sales Service Impact					(272,319)	-0.9%	-1.1%
45	Direct Purchase Impact					(188,258)	-2.0%	-10.7%
	Large Rate T2							
46	Delivery Charges	2,919,381	0.7888	2,609,795	0.7052	(309,586)	-10.6%	-10.6%
47	Federal Carbon Charge	14,470,480	3.9100	14,470,480	3.9100	-	0.0%	0.0%
48	Gas Supply Charges	41,829,309	11.3025	41,672,021	11.2600	(157,288)	-0.4%	-0.4%
49	Total Bill	59,219,170	16.0013	58,752,296	15.8752	(466,874)	-0.8%	-1.0%
50	Sales Service Impact					(466,874)	-0.8%	-1.0%
51	Direct Purchase Impact					(309,586)	-1.8%	-10.6%
	Large Rate T3							
52	Delivery Charges	5,604,537	2.0551	5,123,067	1.8786	(481,471)		-8.6%
53	Gas Supply Charges	30,823,274	11.3025	30,707,371	11.2600	(115,903)		-0.4%
54	Total Bill	36,427,811	13.3576	35,830,438	13.1386	(597,373)		-1.6%
55	Sales Service Impact					(597,373)		-1.6%
56	Direct Purchase Impact					(481,471)		-8.6%

Notes:
(1) Reflects approved rates per EB-2019-0194, Exhibit D, Tab 2, Rate Order, Appendix A.

UNION RATE ZONES
Union North In-Franchise
Calculation of 2020 Sales Service and Direct Purchase Bill Impacts for Typical Small and Large Customers

Line No.	Particulars	Approved - EB-2019-0194 (1) Total Bill ($)	Approved - EB-2019-0194 (1) Unit Rate (cents/m^3)	Updated for Cost Study (without proposals) Total Bill ($)	Updated for Cost Study (without proposals) Unit Rate (cents/m^3)	Total Bill Change ($)	Bill Impact Including Federal Carbon Charge (%)	Bill Impact Excluding Federal Carbon Charge (%)
		(a)	(b)	(c)	(d)	(e) = (c - a)	(f) = (e / a)	(g)
	Small Rate 01							
1	Delivery Charges	475	21.6105	489	22.2245	13.51	2.8%	2.8%
2	Federal Carbon Charge	86	3.9100	86	3.9100	-	0.0%	0.0%
3	Gas Supply Charges (2)	411	18.6827	404	18.3850	(6.55)	-1.6%	-1.6%
4	Total Bill	972	44.2027	979	44.5191	6.96	0.7%	0.8%
5	Sales Service Impact					6.96	0.7%	0.8%
6	Bundled-T (Direct Purchase) Impact					6.96	1.1%	1.2%
	Small Rate 10							
7	Delivery Charges	5,112	8.5204	6,106	10.1769	994	19.4%	19.4%
8	Federal Carbon Charge	2,346	3.9100	2,346	3.9100	-	0.0%	0.0%
9	Gas Supply Charges (2)	10,204	17.0074	10,199	16.9988	(5)	-0.1%	-0.1%
10	Total Bill	17,663	29.4378	18,651	31.0857	989	5.6%	6.5%
11	Sales Service Impact					989	5.6%	6.5%
12	Bundled-T (Direct Purchase) Impact					1,014	9.5%	12.1%
	Large Rate 10							
13	Delivery Charges	16,685	6.6740	20,403	8.1614	3,718	22.3%	22.3%
14	Federal Carbon Charge	9,775	3.9100	9,775	3.9100	-	0.0%	0.0%
15	Gas Supply Charges (2)	42,519	17.0074	42,497	16.9988	(22)	-0.1%	-0.1%
16	Total Bill	68,979	27.5914	72,675	29.0702	3,697	5.4%	6.2%
17	Sales Service Impact					3,697	5.4%	6.2%
18	Bundled-T (Direct Purchase) Impact					3,803	9.5%	12.6%
	Small Rate 20							
19	Delivery Charges	88,161	2.9387	85,455	2.8485	(2,706)	-3.1%	-3.1%
20	Federal Carbon Charge	117,300	3.9100	117,300	3.9100	-	0.0%	0.0%
21	Gas Supply Charges (2)	406,896	13.5632	435,668	14.5223	28,772	7.1%	7.1%
22	Total Bill	612,357	20.4119	638,423	21.2808	26,066	4.3%	5.3%
23	Sales Service Impact					26,066	4.3%	5.3%
24	Bundled-T (Direct Purchase) Impact					27,341	10.0%	17.4%
	Large Rate 20							
25	Delivery Charges	344,338	2.2956	333,934	2.2262	(10,404)	-3.0%	-3.0%
26	Federal Carbon Charge	586,500	3.9100	586,500	3.9100	-	0.0%	0.0%
27	Gas Supply Charges (2)	1,985,265	13.2351	2,107,661	14.0511	122,396	6.2%	6.2%
28	Total Bill	2,916,103	19.4407	3,028,095	20.1873	111,992	3.8%	4.8%
29	Sales Service Impact					111,992	3.8%	4.8%
30	Bundled-T (Direct Purchase) Impact					118,367	9.7%	18.5%
	Average Rate 25							
31	Delivery Charges	72,987	3.2082	123,939	5.4478	50,952	69.8%	69.8%
32	Federal Carbon Charge	88,953	3.9100	88,953	3.9100	-	0.0%	0.0%
33	Gas Supply Charges (2)	280,146	12.3141	282,302	12.4089	2,157	0.8%	0.8%
34	Total Bill	442,085	19.4323	495,193	21.7667	53,108	12.0%	15.0%
35	Sales Service Impact					53,108	12.0%	15.0%
36	T-Service (Direct Purchase) Impact					50,952	31.5%	69.8%
	Small Rate 100							
37	Delivery Charges	317,202	1.1748	354,479	1.3129	37,277	11.8%	11.8%
38	Federal Carbon Charge	1,055,700	3.9100	1,055,700	3.9100	-	0.0%	0.0%
39	Gas Supply Charges (2)	4,605,591	17.0577	4,594,116	17.0152	(11,475)	-0.2%	-0.2%
40	Total Bill	5,978,493	22.1426	6,004,294	22.2381	25,802	0.4%	0.5%
41	Sales Service Impact					25,802	0.4%	0.5%
42	T-Service (Direct Purchase) Impact					37,277	2.7%	11.8%
	Large Rate 100							
43	Delivery Charges	2,591,790	1.0799	2,894,108	1.2059	302,318	11.7%	11.7%
44	Federal Carbon Charge	9,384,000	3.9100	9,384,000	3.9100	-	0.0%	0.0%
45	Gas Supply Charges (2)	40,330,491	16.8044	40,228,491	16.7619	(102,000)	-0.3%	-0.3%
46	Total Bill	52,306,281	21.7943	52,506,599	21.8777	200,318	0.4%	0.5%
47	Sales Service Impact					200,318	0.4%	0.5%
48	T-Service (Direct Purchase) Impact					302,318	2.5%	11.7%

Notes:
(1) Reflects approved rates per EB-2019-0194, Exhibit D, Tab 2, Rate Order, Appendix A.
(2) Gas Supply charges based on Union North East Zone.

UNION RATE ZONES
Union South In-Franchise
Calculation of 2020 Sales Service and Direct Purchase Bill Impacts for Typical Small and Large Customers

Line No.	Particulars	Approved - EB-2019-0194 (1) Total Bill ($) (a)	Approved - EB-2019-0194 (1) Unit Rate (cents/m^3) (b)	Updated for Cost Study (without proposals) Total Bill ($) (c)	Updated for Cost Study (without proposals) Unit Rate (cents/m^3) (d)	Updated for Cost Study (without proposals) Total Bill Change ($) (e) = (c - a)	Bill Impact Including Federal Carbon Charge (%) (f) = (e / a)	Bill Impact Excluding Federal Carbon Charge (%) (g)
	Small Rate M1							
1	Delivery Charges	399	18.1218	401	18.2386	2.57	0.6%	0.6%
2	Federal Carbon Charge	86	3.9100	86	3.9100	-	0.0%	0.0%
3	Gas Supply Charges	249	11.3023	248	11.2595	(0.94)	-0.4%	-0.4%
4	Total Bill	733	33.3336	735	33.4077	1.63	0.2%	0.3%
5	Sales Service Impact					1.63	0.2%	0.3%
6	Direct Purchase Impact					2.57	0.5%	0.6%
	Small Rate M2							
7	Delivery Charges	4,111	6.8519	4,398	7.3308	287	7.0%	7.0%
8	Federal Carbon Charge	2,346	3.9100	2,346	3.9100	-	0.0%	0.0%
9	Gas Supply Charges	6,782	11.3025	6,756	11.2600	(26)	-0.4%	-0.4%
10	Total Bill	13,239	22.0644	13,500	22.5008	262	2.0%	2.4%
11	Sales Service Impact					262	2.0%	2.4%
12	Direct Purchase Impact					287	4.5%	7.0%
	Large Rate M2							
13	Delivery Charges	13,718	5.4872	14,853	5.9411	1,135	8.3%	8.3%
14	Federal Carbon Charge	9,775	3.9100	9,775	3.9100	-	0.0%	0.0%
15	Gas Supply Charges	28,256	11.3025	28,150	11.2600	(106)	-0.4%	-0.4%
16	Total Bill	51,749	20.6997	52,778	21.1111	1,028	2.0%	2.5%
17	Sales Service Impact					1,028	2.0%	2.5%
18	Direct Purchase Impact					1,135	4.8%	8.3%
	Small Rate M4							
19	Delivery Charges	48,933	5.5923	58,008	6.6294	9,075	18.5%	18.5%
20	Federal Carbon Charge	34,213	3.9100	34,213	3.9100	-	0.0%	0.0%
21	Gas Supply Charges	98,897	11.3025	98,525	11.2600	(372)	-0.4%	-0.4%
22	Total Bill	182,042	20.8048	190,745	21.7994	8,703	4.8%	5.9%
23	Sales Service Impact					8,703	4.8%	5.9%
24	Direct Purchase Impact					9,075	10.9%	18.5%
	Large Rate M4							
25	Delivery Charges	370,929	3.0911	439,066	3.6589	68,137	18.4%	18.4%
26	Federal Carbon Charge	469,200	3.9100	469,200	3.9100	-	0.0%	0.0%
27	Gas Supply Charges	1,356,300	11.3025	1,351,200	11.2600	(5,100)	-0.4%	-0.4%
28	Total Bill	2,196,429	18.3036	2,259,466	18.8289	63,037	2.9%	3.6%
29	Sales Service Impact					63,037	2.9%	3.6%
30	Direct Purchase Impact					68,137	8.1%	18.4%
	Small Rate M5							
31	Delivery Charges	32,447	3.9330	34,198	4.1452	1,751	5.4%	5.4%
32	Federal Carbon Charge	32,258	3.9100	32,258	3.9100	-	0.0%	0.0%
33	Gas Supply Charges	93,246	11.3025	92,895	11.2600	(351)	-0.4%	-0.4%
34	Total Bill	157,950	19.1455	159,351	19.3152	1,401	0.9%	1.1%
35	Sales Service Impact					1,401	0.9%	1.1%
36	Direct Purchase Impact					1,751	2.7%	5.4%
	Large Rate M5							
37	Delivery Charges	182,217	2.8033	192,152	2.9562	9,935	5.5%	5.5%
38	Federal Carbon Charge	254,150	3.9100	254,150	3.9100	-	0.0%	0.0%
39	Gas Supply Charges	734,663	11.3025	731,900	11.2600	(2,763)	-0.4%	-0.4%
40	Total Bill	1,171,030	18.0158	1,178,202	18.1262	7,172	0.6%	0.8%
41	Sales Service Impact					7,172	0.6%	0.8%
42	Direct Purchase Impact					9,935	2.3%	5.5%
	Small Rate M7							
43	Delivery Charges	760,766	2.1132	940,906	2.6136	180,140	23.7%	23.7%
44	Federal Carbon Charge	1,407,600	3.9100	1,407,600	3.9100	-	0.0%	0.0%
45	Gas Supply Charges	4,068,900	11.3025	4,053,600	11.2600	(15,300)	-0.4%	-0.4%
46	Total Bill	6,237,266	17.3257	6,402,106	17.7836	164,840	2.6%	3.4%
47	Sales Service Impact					164,840	2.6%	3.4%
48	Direct Purchase Impact					180,140	8.3%	23.7%
	Large Rate M7							
49	Delivery Charges	3,067,592	5.8992	3,790,183	7.2888	722,591	23.6%	23.6%
50	Federal Carbon Charge	2,033,200	3.9100	2,033,200	3.9100	-	0.0%	0.0%
51	Gas Supply Charges	5,877,300	11.3025	5,855,200	11.2600	(22,100)	-0.4%	-0.4%
52	Total Bill	10,978,092	21.1117	11,678,583	22.4588	700,491	6.4%	7.8%
53	Sales Service Impact					700,491	6.4%	7.8%
54	Direct Purchase Impact					722,591	14.2%	23.6%

Notes:
(1) Reflects approved rates per EB-2019-0194, Exhibit D, Tab 2, Rate Order, Appendix A.

UNION RATE ZONES
Union South In-Franchise
Calculation of 2020 Sales Service and Direct Purchase Bill Impacts for Typical Small and Large Customers

		Approved - EB-2019-0194 (1)		Updated for Cost Study (without proposals)			Bill Impact	
Line No.	Particulars	Total Bill ($)	Unit Rate (cents/m^3)	Total Bill ($)	Unit Rate (cents/m^3)	Total Bill Change ($)	Including Federal Carbon Charge (%)	Excluding Federal Carbon Charge (%)
		(a)	(b)	(c)	(d)	(e) = (c - a)	(f) = (e / a)	(g)
	Small Rate M9							
1	Delivery Charges	173,981	2.5033	184,837	2.6595	10,856		6.2%
2	Gas Supply Charges	785,524	11.3025	782,570	11.2600	(2,954)		-0.4%
3	Total Bill	959,505	13.8058	967,407	13.9195	7,902		0.8%
4	Sales Service Impact					7,902		0.8%
5	Direct Purchase Impact					10,856		6.2%
	Large Rate M9							
6	Delivery Charges	517,516	2.5648	549,806	2.7248	32,290		6.2%
7	Gas Supply Charges	2,280,618	11.3025	2,272,043	11.2600	(8,576)		-0.4%
8	Total Bill	2,798,135	13.8673	2,821,849	13.9848	23,714		0.8%
9	Sales Service Impact					23,714		0.8%
10	Direct Purchase Impact					32,290		6.2%
	Average Rate M10							
11	Delivery Charges	7,208	7.6274	6,463	6.8391	(745)		-10.3%
12	Gas Supply Charges	10,681	11.3025	10,641	11.2600	(40)		-0.4%
13	Total Bill	17,889	18.9299	17,104	18.0991	(785)		-4.4%
14	Sales Service Impact					(785)		-4.4%
15	Direct Purchase Impact					(745)		-10.3%
	Small Rate T1							
16	Delivery Charges	161,004	2.1362	174,227	2.3116	13,224	8.2%	8.2%
17	Federal Carbon Charge	294,697	3.9100	294,697	3.9100	-	0.0%	0.0%
18	Gas Supply Charges	851,869	11.3025	848,666	11.2600	(3,203)	-0.4%	-0.4%
19	Total Bill	1,307,570	17.3487	1,317,590	17.4816	10,020	0.8%	1.0%
20	Sales Service Impact					10,020	0.8%	1.0%
21	Direct Purchase Impact					13,224	2.9%	8.2%
	Average Rate T1							
22	Delivery Charges	249,405	2.1564	269,803	2.3327	20,398	8.2%	8.2%
23	Federal Carbon Charge	452,228	3.9100	452,228	3.9100	-	0.0%	0.0%
24	Gas Supply Charges	1,307,240	11.3025	1,302,325	11.2600	(4,916)	-0.4%	-0.4%
25	Total Bill	2,008,873	17.3689	2,024,356	17.5027	15,483	0.8%	1.0%
26	Sales Service Impact					15,483	0.8%	1.0%
27	Direct Purchase Impact					20,398	2.9%	8.2%
	Large Rate T1							
28	Delivery Charges	559,233	2.1825	604,737	2.3600	45,504	8.1%	8.1%
29	Federal Carbon Charge	1,001,902	3.9100	1,001,902	3.9100	-	0.0%	0.0%
30	Gas Supply Charges	2,896,162	11.3025	2,885,271	11.2600	(10,890)	-0.4%	-0.4%
31	Total Bill	4,457,296	17.3950	4,491,910	17.5300	34,614	0.8%	1.0%
32	Sales Service Impact					34,614	0.8%	1.0%
33	Direct Purchase Impact					45,504	2.9%	8.1%
	Small Rate T2							
34	Delivery Charges	731,795	1.2350	727,935	1.2285	(3,860)	-0.5%	-0.5%
35	Federal Carbon Charge	2,316,910	3.9100	2,316,910	3.9100	-	0.0%	0.0%
36	Gas Supply Charges	6,697,409	11.3025	6,672,226	11.2600	(25,184)	-0.4%	-0.4%
37	Total Bill	9,746,114	16.4475	9,717,070	16.3985	(29,044)	-0.3%	-0.4%
38	Sales Service Impact					(29,044)	-0.3%	-0.4%
39	Direct Purchase Impact					(3,860)	-0.1%	-0.5%
	Average Rate T2							
40	Delivery Charges	1,766,761	0.8933	1,757,589	0.8886	(9,172)	-0.5%	-0.5%
41	Federal Carbon Charge	7,733,583	3.9100	7,733,583	3.9100	-	0.0%	0.0%
42	Gas Supply Charges	22,355,198	11.3025	22,271,137	11.2600	(84,061)	-0.4%	-0.4%
43	Total Bill	31,855,542	16.1058	31,762,309	16.0586	(93,233)	-0.3%	-0.4%
44	Sales Service Impact					(93,233)	-0.3%	-0.4%
45	Direct Purchase Impact					(9,172)	-0.1%	-0.5%
	Large Rate T2							
46	Delivery Charges	2,919,381	0.7888	2,904,302	0.7848	(15,079)	-0.5%	-0.5%
47	Federal Carbon Charge	14,470,480	3.9100	14,470,480	3.9100	-	0.0%	0.0%
48	Gas Supply Charges	41,829,309	11.3025	41,672,021	11.2600	(157,288)	-0.4%	-0.4%
49	Total Bill	59,219,170	16.0013	59,046,803	15.9548	(172,367)	-0.3%	-0.4%
50	Sales Service Impact					(172,367)	-0.3%	-0.4%
51	Direct Purchase Impact					(15,079)	-0.1%	-0.5%
	Large Rate T3							
52	Delivery Charges	5,604,537	2.0551	5,605,520	2.0555	982		0.0%
53	Gas Supply Charges	30,823,274	11.3025	30,707,371	11.2600	(115,903)		-0.4%
54	Total Bill	36,427,811	13.3576	36,312,891	13.3155	(114,920)		-0.3%
55	Sales Service Impact					(114,920)		-0.3%
56	Direct Purchase Impact					982		0.0%

Notes:
(1) Reflects approved rates per EB-2019-0194, Exhibit D, Tab 2, Rate Order, Appendix A.

UNION RATE ZONES

Derivation of Cost Allocation Study Directive Rate Impacts

Line No.	Particulars	Billing Units	2019 Forecast Usage (10^3m^3)(1)	Cost Study Including Proposals Revenue (Deficiency)/ Sufficiency ($000s)(2)	Cost Study Excluding Proposals Revenue (Deficiency)/ Sufficiency ($000s) (3)	Cost Allocation Study Rates Including Proposals (cents / m^3)	Cost Allocation Study Rates Excluding Proposals (cents / m^3)
			(a)	(b)	(c)	(d)= (b / a)	(e)= (c / a)
	Rate 01 General Service						
1	Monthly Charge	bills	4,191,053	-	-		
	Monthly Delivery Charge - All Zones						
2	First 100 m^3	10^3m^3	307,954	(1,933)	(1,933)	0.6278	0.6278
3	Next 200 m^3	10^3m^3	335,578	(2,040)	(2,040)	0.6078	0.6078
4	Next 200 m^3	10^3m^3	128,567	(749)	(749)	0.5826	0.5826
5	Next 500 m^3	10^3m^3	85,787	(480)	(480)	0.5593	0.5593
6	Over 1,000 m^3	10^3m^3	117,553	(635)	(635)	0.5401	0.5401
7	Delivery Commodity charge - 01		975,438	(5,837)	(5,837)		
8	Total Delivery - 01		975,438	(5,837)	(5,837)		
	Gas Transportation						
9	North West	10^3m^3	281,973	44	44	-0.0157	-0.0157
10	North East	10^3m^3	693,465	(1,708)	(1,387)	0.2463	0.1999
11	Transportation - 01		975,438	(1,664)	(1,342)		
	Storage						
12	North West	10^3m^3	281,973	2,005	2,101	-0.7111	-0.7453
13	North East	10^3m^3	693,465	2,500	3,146	-0.3604	-0.4536
14	Storage - 01		975,438	4,505	5,247		
15	Total Gas Transportation and Storage	10^3m^3	975,438	2,841	3,905		
16	Total Rate 01		975,438	(2,996)	(1,932)		

Notes:
(1) Exhibit B, Tab 1, Schedule 1, Appendix C, Working Papers, Schedule 5, pp. 4-14, column (a), including preliminary rate design changes.
(2) Exhibit B, Tab 1, Schedule 1, Appendix C, Working Papers, Schedule 5, pp. 4-14, column (g).
(3) Rate class totals per Exhibit B, Tab 1, Schedule 1, Appendix C, Working Papers, Schedule 4, p. 1, column (d).

UNION RATE ZONES
Derivation of Cost Allocation Study Directive Rate Impacts

Line No.	Particulars	Billing Units	2019 Forecast Usage (10^3m^3)(1)	Cost Study Including Proposals Revenue (Deficiency)/ Sufficiency ($000s)(2)	Cost Study Excluding Proposals Revenue (Deficiency)/ Sufficiency ($000s) (3)	Cost Allocation Study Rates Including Proposals (cents / m³)	Cost Allocation Study Rates Excluding Proposals (cents / m³)
			(a)	(b)	(c)	(d)= (b / a)	(e)= (c / a)
	Rate 10 General Service						
1	Monthly Charge	bills	22,534	-	-		
	Monthly Delivery Charge - All Zones						
2	First 1,000 m³	10³m³	21,557	(421)	(421)	1.9523	1.9523
3	Next 9,000 m³	10³m³	123,534	(1,955)	(1,955)	1.5825	1.5825
4	Next 20,000 m³	10³m³	84,904	(1,180)	(1,180)	1.3902	1.3902
5	Next 70,000 m³	10³m³	64,345	(807)	(807)	1.2535	1.2535
6	Over 100,000 m³	10³m³	48,461	(356)	(356)	0.7356	0.7356
7	Delivery Commodity Charge - 10		342,801	(4,719)	(4,719)		
8	Total Delivery - 10		342,801	(4,719)	(4,719)		
	Gas Transportation						
9	North West	10³m³	83,676	2	2	-0.0022	-0.0022
10	North East	10³m³	254,630	(694)	(579)	0.2726	0.2274
11	Transportation - 10		338,306	(692)	(577)		
	Storage						
12	North West	10³m³	83,676	383	407	-0.4581	-0.4867
13	North East	10³m³	254,630	301	493	-0.1181	-0.1935
14	Storage - 10		338,306	684	900		
15	Total Gas Transportation, Storage and Gas Supply Commodity		338,306	(8)	323		
16	Total Rate 10		342,801	(4,727)	(4,396)		

Notes:
(1) Exhibit B, Tab 1, Schedule 1, Appendix C, Working Papers, Schedule 5, pp. 4-14, column (a), including preliminary rate design changes.
(2) Exhibit B, Tab 1, Schedule 1, Appendix C, Working Papers, Schedule 5, pp. 4-14, column (g).
(3) Rate class totals per Exhibit B, Tab 1, Schedule 1, Appendix C, Working Papers, Schedule 4, p. 1, column (d).

UNION RATE ZONES
Derivation of Cost Allocation Study Directive Rate Impacts

Line No.	Particulars	Billing Units	2019 Forecast Usage (10^3m^3)(1) (a)	Cost Study Including Proposals Revenue (Deficiency)/ Sufficiency ($000s)(2) (b)	Cost Study Excluding Proposals Revenue (Deficiency)/ Sufficiency ($000s) (3) (c)	Cost Allocation Study Rates Including Proposals (cents / m^3) (d)= (b / a)	Cost Allocation Study Rates Excluding Proposals (cents / m^3) (e)= (c / a)
	Rate 20 Medium Volume Firm Service						
1	Monthly Charge	bills	678	23	23	-$34.08	-$34.08
	Monthly Demand Charge						
2	First 70,000 m^3	10^3m^3/d	22,165	221	221	-0.9974	-0.9974
3	All over 70,000 m^3	10^3m^3/d	66,148	388	388	-0.5865	-0.5865
4	Total Demand - 20		88,312	609	609		
	Monthly Commodity Charge						
5	First 852,000 m^3	10^3m^3	300,681	62	62	-0.0207	-0.0207
6	All over 852,000 m^3	10^3m^3	618,545	90	90	-0.0146	-0.0146
7	Delivery (Commodity/Demand)		919,226	153	153		
8	Transportation Account Charge		428				
9	Total Delivery - 20		919,226	785	785		
	Gas Supply Demand Charge						
10	North West	10^3m^3/d	1,788	38	40	-2.1171	-2.2472
11	North East	10^3m^3/d	6,323	(1,103)	(1,029)	17.4443	16.2736
	Commodity Transportation 1						
12	North West	10^3m^3	18,346	(10)	(9)	0.0557	0.0473
13	North East	10^3m^3	50,366	(848)	(798)	1.6829	1.5849
	Commodity Transportation 2						
14	North West	10^3m^3	11,643	-	-	-	-
15	North East	10^3m^3	32,687	-	-	-	-
16	Gas Supply Transportation - 20		113,042	(1,923)	(1,796)		
	Storage (GJ's)						
17	Demand	GJ/d	141,504	1,078	1,122	-1.377	-1.676
18	Commodity	GJ	1,033,187	-	-		
19	Total Storage Rate - 20		1,174,691	1,078	1,122		
20	Total Rate 20		919,226	(60)	111		

Notes:
(1) Exhibit B, Tab 1, Schedule 1, Appendix C, Working Papers, Schedule 5, pp. 4-14, column (a), including preliminary rate design changes.
(2) Exhibit B, Tab 1, Schedule 1, Appendix C, Working Papers, Schedule 5, pp. 4-14, column (g).
(3) Rate class totals per Exhibit B, Tab 1, Schedule 1, Appendix C, Working Papers, Schedule 4, p. 1, column (d).

UNION RATE ZONES
Derivation of Cost Allocation Study Directive Rate Impacts

Line No.	Particulars	Billing Units	2019 Forecast Usage (10^3m^3)(1) (a)	Cost Study Including Proposals Revenue (Deficiency)/ Sufficiency ($000s)(2) (b)	Cost Study Excluding Proposals Revenue (Deficiency)/ Sufficiency ($000s) (3) (c)	Cost Allocation Study Rates Including Proposals (cents / m^3) (d)= (b / a)	Cost Allocation Study Rates Excluding Proposals (cents / m^3) (e)= (c / a)
	Rate 25 Large Volume Interruptible Service						
1	Monthly Charge	bills	756	(178)	(178)	$235.71	$235.71
2	Monthly Delivery Charge	10^3m^3	67,098	(1,419)	(1,419)	2.1153	2.1153
3	Transportation Account Charge		141				
4	Total Delivery - 25		67,098	(1,598)	(1,598)		
5	Gas Supply Transportation - 25	10^3m^3	34,910	(38)	(33)	0.1078	0.0948
6	Total Rate 25		67,098	(1,635)	(1,631)		
	Rate 100 Large Volume Firm Service						
7	Monthly Charge	bills	156	(31)	(31)	$198.24	$198.24
8	Demand	$10^3m^3/d$	39,647	(872)	(872)	2.1994	2.1994
9	Commodity	10^3m^3	878,440	(277)	(277)	0.0315	0.0315
10	Delivery (Commodity/Demand)		878,440	(1,176)	(1,176)		
11	Transportation Account Charge		153				
12	Total Delivery - 100		878,440	(1,180)	(1,180)		
	Storage (GJ's)						
13	Demand	GJ/d	14,400	20	24	-1.377	-1.676
14	Commodity	GJ	100,000	-	-		
15	Total Storage Rate - 100		114,400	20	24		
16	Total Rate 100		878,440	(1,160)	(1,155)		

Notes:
(1) Exhibit B, Tab 1, Schedule 1, Appendix C, Working Papers, Schedule 5, pp. 4-14, column (a), including preliminary rate design changes.
(2) Exhibit B, Tab 1, Schedule 1, Appendix C, Working Papers, Schedule 5, pp. 4-14, column (g).
(3) Rate class totals per Exhibit B, Tab 1, Schedule 1, Appendix C, Working Papers, Schedule 4, p. 1, column (d).

UNION RATE ZONES
Derivation of Cost Allocation Study Directive Rate Impacts

Line No.	Particulars		Billing Units	2019 Forecast Usage (10^3m^3)(1)	Cost Study Including Proposals Revenue (Deficiency)/ Sufficiency ($000s)(2)	Cost Study Excluding Proposals Revenue (Deficiency)/ Sufficiency ($000s) (3)	Cost Allocation Study Rates Including Proposals (cents / m³)	Cost Allocation Study Rates Excluding Proposals (cents / m³)
				(a)	(b)	(c)	(d)= (b / a)	(e)= (c / a)
	M1							
1	Monthly Charge		bills	13,523,532	-	-		
	Monthly Delivery Commodity Charge							
2	First	100 m³	10^3m^3	1,001,501	(2,136)	(1,974)	0.2133	0.1971
3	Next	150 m³	10^3m^3	860,574	(1,739)	(1,607)	0.2021	0.1867
4	All over	250 m³	10^3m^3	1,189,227	(2,059)	(1,903)	0.1732	0.1600
5	Delivery Commodity Charge - M1			3,051,302	(5,935)	(5,484)		
6	Total Delivery - M1			3,051,302	(5,935)	(5,484)		
7	Storage - M1		10^3m^3	3,051,302	2,175	2,175	-0.0713	-0.0713
8	Total Rate M1			3,051,302	(3,760)	(3,308)		
	M2							
9	Monthly Charge		bills	84,262	-	-		
	Monthly Delivery Commodity Charge							
10	First	1,000 m³	10^3m^3	79,260	(400)	(389)	0.5044	0.4904
11	Next	6,000 m³	10^3m^3	344,741	(1,706)	(1,658)	0.4948	0.4810
12	Next	13,000 m³	10^3m^3	328,477	(1,543)	(1,500)	0.4698	0.4568
13	All over	20,000 m³	10^3m^3	432,256	(1,880)	(1,828)	0.4350	0.4229
14	Delivery Commodity Charge - M2			1,184,733	(5,529)	(5,376)		
15	Total Delivery - M2			1,184,733	(5,529)	(5,376)		
16	Storage - M2		10^3m^3	1,184,733	1,603	1,603	-0.1353	-0.1353
17	Total Rate M2			1,184,733	(3,927)	(3,773)		

Notes:
(1) Exhibit B, Tab 1, Schedule 1, Appendix C, Working Papers, Schedule 5, pp. 4-14, column (a), including preliminary rate design changes.
(2) Exhibit B, Tab 1, Schedule 1, Appendix C, Working Papers, Schedule 5, pp. 4-14, column (g).
(3) Rate class totals per Exhibit B, Tab 1, Schedule 1, Appendix C, Working Papers, Schedule 4, p. 1, column (d).

UNION RATE ZONES
Derivation of Cost Allocation Study Directive Rate Impacts

Line No.	Particulars	Billing Units	2019 Forecast Usage (10^3m^3)(1)	Cost Study Including Proposals Revenue (Deficiency)/ Sufficiency ($000s)(2)	Cost Study Excluding Proposals Revenue (Deficiency)/ Sufficiency ($000s) (3)	Cost Allocation Study Rates Including Proposals (cents / m^3)	Cost Allocation Study Rates Excluding Proposals (cents / m^3)
			(a)	(b)	(c)	(d)= (b / a)	(e)= (c / a)
	M4 Firm Commercial/Industrial Contract Rate						
	Monthly Demand Charge						
1	First 8,450 m^3	10^3m^3/d	20,206	(3,815)	(2,352)	18.8801	11.641
2	Next 19,700 m^3	10^3m^3/d	15,556	(1,317)	(812)	8.4654	5.2195
3	All over 28,150 m^3	10^3m^3/d	9,419	(670)	(413)	7.112	4.3851
			45,181	(5,802)	(3,577)		
	Monthly Delivery Commodity Charge						
4	First Block	10^3m^3	696,659	(3,059)	(1,886)	0.4391	0.2708
5	All remaining use	10^3m^3	1,007	(2)	(1)	0.1579	0.0974
6	Delivery Commodity Charge		697,667	(3,061)	(1,887)		
7	Total Delivery - Firm M4		697,667	(8,863)	(5,465)		
	Interruptible contracts						
8	Monthly Charge	bills	60	(13)	(8)	$59.12	$46.80
9	Delivery Commodity Charge (Avg Price)	10^3m^3	3,606	(30)	(18)	0.8247	0.5085
10	Total Delivery - Interruptible M4		3,606	(42)	(26)		
11	Total Delivery - M4		701,273	(8,905)	(5,491)		
12	Total Rate M4		701,273	(8,905)	(5,491)		

Notes:

(1) Exhibit B, Tab 1, Schedule 1, Appendix C, Working Papers, Schedule 5, pp. 4-14, column (a), including preliminary rate design changes.

(2) Exhibit B, Tab 1, Schedule 1, Appendix C, Working Papers, Schedule 5, pp. 4-14, column (g).

(3) Rate class totals per Exhibit B, Tab 1, Schedule 1, Appendix C, Working Papers, Schedule 4, p. 1, column (d).

UNION RATE ZONES
Derivation of Cost Allocation Study Directive Rate Impacts

Line No.	Particulars	Billing Units	2019 Forecast Usage (10^3m^3)(1)	Cost Study Including Proposals Revenue (Deficiency)/ Sufficiency ($000s)(2)	Cost Study Excluding Proposals Revenue (Deficiency)/ Sufficiency ($000s) (3)	Cost Allocation Study Rates Including Proposals (cents / m^3)	Cost Allocation Study Rates Excluding Proposals (cents / m^3)
			(a)	(b)	(c)	(d)= (b / a)	(e)= (c / a)
	M5A Interruptible Commercial/Industrial Contract Rate						
	Firm contracts						
1	Monthly Demand Charge	$10^3m^3/d$	529	(11)	(10)	2.1647	1.9307
2	Monthly Delivery Commodity Charge	10^3m^3	9,183	(13)	(12)	0.1418	0.1265
3	Total Delivery - Firm M5		9,183	(24)	(22)		
	Interruptible contracts						
4	Monthly Charge	bills	528	(22)	(20)	$59.12	$46.80
5	Delivery Commodity Charge (Avg Price)	10^3m^3	65,670	(106)	(95)	0.1617	0.1442
6	Total Delivery -Interruptible M5		65,670	(128)	(114)		
7	Total Delivery - M5		74,853	(153)	(136)		
8	Total Rate M5A		74,853	(153)	(136)		

Notes:
(1) Exhibit B, Tab 1, Schedule 1, Appendix C, Working Papers, Schedule 5, pp. 4-14, column (a), including preliminary rate design changes.
(2) Exhibit B, Tab 1, Schedule 1, Appendix C, Working Papers, Schedule 5, pp. 4-14, column (g).
(3) Rate class totals per Exhibit B, Tab 1, Schedule 1, Appendix C, Working Papers, Schedule 4, p. 1, column (d).

UNION RATE ZONES
Derivation of Cost Allocation Study Directive Rate Impacts

Line No.	Particulars	Billing Units	2019 Forecast Usage (10^3m^3)(1)	Cost Study Including Proposals Revenue (Deficiency)/ Sufficiency ($000s)(2)	Cost Study Excluding Proposals Revenue (Deficiency)/ Sufficiency ($000s) (3)	Cost Allocation Study Rates Including Proposals (cents / m³)	Cost Allocation Study Rates Excluding Proposals (cents / m³)
			(a)	(b)	(c)	(d)= (b / a)	(e)= (c / a)
	M7 Special Large Volume Contract Rate						
	Firm Contracts						
1	Monthly Demand Charge	$10^3m^3/d$	27,657	(2,921)	(2,213)	10.5602	7.9998
2	Monthly Delivery Commodity Charge	10^3m^3	413,352	(329)	(249)	0.0797	0.0604
3	Total Delivery - Firm M7		413,352	(3,250)	(2,462)		
	Interruptible / Seasonal Contracts						
4	Monthly Delivery Commodity Charge - M7	10^3m^3	89,687	(599)	(454)	0.6678	0.5059
5	Total Delivery - M7		503,039	(3,849)	(2,916)		
6	Total Rate M7		503,039	(3,849)	(2,916)		
	M9 Large Wholesale Service						
7	Monthly Demand Charge	$10^3m^3/d$	4,410	10	(67)	-0.2319	1.5187
8	Monthly Delivery Commodity Charge	10^3m^3	81,243	1	(7)	-0.0012	0.0082
9	Total Delivery - M9		81,243	11	(74)		
10	Total Rate M9		81,243	11	(74)		
	M10 Small Wholesale Service						
11	Total Delivery - M10	10^3m^3	277	3	2	-1.0697	-0.7883
12	Total Rate M10		277	3	2		

Notes:
(1) Exhibit B, Tab 1, Schedule 1, Appendix C, Working Papers, Schedule 5, pp. 4-14, column (a), including preliminary rate design changes.
(2) Exhibit B, Tab 1, Schedule 1, Appendix C, Working Papers, Schedule 5, pp. 4-14, column (g).
(3) Rate class totals per Exhibit B, Tab 1, Schedule 1, Appendix C, Working Papers, Schedule 4, p. 1, column (d).

UNION RATE ZONES
Derivation of Cost Allocation Study Directive Rate Impacts

Line No.	Particulars	Billing Units	2019 Forecast Usage (10^3m^3)(1)	Cost Study Including Proposals Revenue (Deficiency)/ Sufficiency ($000s)(2)	Cost Study Excluding Proposals Revenue (Deficiency)/ Sufficiency ($000s) (3)	Cost Allocation Study Rates Including Proposals (cents / m³)	Cost Allocation Study Rates Excluding Proposals (cents / m³)
			(a)	(b)	(c)	(d)= (b / a)	(e)= (c / a)
	T1 Storage and Transportation						
	Storage ($/GJ's)						
	Demand:						
	Firm injection / withdrawal						
1	Union provides deliverability inventory	GJ/d/mo.	601,860	525	526	-0.769	-0.767
2	Customer provides deliverability inventory	GJ/d/mo.	-	-	-	-0.685	-0.683
3	Incremental firm injection right	GJ/d/mo.	-	-	-	-0.685	-0.683
4	Interruptible	GJ/d/mo.	-	-	-	-0.685	-0.683
5	Space	GJ/d/mo.	16,456,404	21	22	-0.001	-0.001
	Commodity:			-	-		
6	Commodity (Customer Provides)	GJ	4,957,892	18	18	-0.004	-0.004
7	Commodity (Union Provides)	GJ	-	-	-		
8	Customer supplied fuel	GJ	20,129	(41)	(41)	0.268%	0.270%
9	Total Storage - T1		449,463	524	525		
	Transportation (cents/ m3)						
	Demand						
10	First 28,150 m³	10³m³/d/m	13,727	(690)	(469)	5.0254	3.4172
11	Next 112,720 m³	10³m³/d/m	10,475	(364)	(247)	3.4720	2.3609
	Commodity						
12	Firm Volumes	10³m³	422,293	(55)	(37)	0.0129	0.0088
13	Interruptible Volumes	10³m³	27,170	(61)	(41)	0.2233	0.1519
14	Monthly Charges	Meter/mo.	552	(135)	(92)	$245.25	$166.77
15	Customer supplied fuel	GJ	53,258	(45)	(45)	0.087%	0.087%
16	Total Transportation - T1		449,463	(1,349)	(931)		
17	Total Delivery - T1	10³m³	449,463	(825)	(407)		

Notes:

(1) Exhibit B, Tab 1, Schedule 1, Appendix C, Working Papers, Schedule 5, pp. 4-14, column (a), including preliminary rate design changes.

(2) Exhibit B, Tab 1, Schedule 1, Appendix C, Working Papers, Schedule 5, pp. 4-14, column (g).

(3) Rate class totals per Exhibit B, Tab 1, Schedule 1, Appendix C, Working Papers, Schedule 4, p. 1, column (d).

UNION RATE ZONES
Derivation of Cost Allocation Study Directive Rate Impacts

Line No.	Particulars		Billing Units	2019 Forecast Usage (10^3m^3)(1)	Cost Study Including Proposals Revenue (Deficiency)/ Sufficiency ($000s)(2)	Cost Study Excluding Proposals Revenue (Deficiency)/ Sufficiency ($000s) (3)	Cost Allocation Study Rates Including Proposals (cents / m³)	Cost Allocation Study Rates Excluding Proposals (cents / m³)
				(a)	(b)	(c)	(d)= (b / a)	(e)= (c / a)
	T2 Storage and Transportation							
	Storage ($/GJ's)							
	Demand:							
	Firm injection / withdrawal							
1	Union provides deliverability inventory		GJ/d/mo.	1,722,864	1,354	1,349	-0.769	-0.767
2	Customer provides deliverability inventory		GJ/d/mo.	843,000	474	471	-0.685	-0.683
3	Incremental firm injection right		GJ/d/mo.	-	-	-	-0.685	-0.683
4	Interruptible		GJ/d/mo.	415,704	552	552	-0.685	-0.683
5	Space		GJ/d/mo.	105,150,000	157	154	-0.001	-0.001
	Commodity:							
6	Commodity (Customer Provides)		GJ	35,065,549	147	146	-0.004	-0.004
7	Commodity (Union Provides)		GJ	-	-	-		
8	Customer supplied fuel		GJ	142,366	(273)	(276)	0.268%	0.270%
9	Total Storage - T2			4,592,825	2,410	2,397		
	Transportation (cents/ m3)							
	Demand							
10	First	140,870 m³	10^3m^3/d/m	56,526	1,971	96	-3.4872	-0.1702
11	All Over	140,870 m³	10^3m^3/d/m	215,266	3,971	194	-1.8446	-0.0900
	Commodity							
12	Firm Volumes		10^3m^3	4,407,552	99	5	-0.0022	-0.0001
13	Interruptible		10^3m^3	185,273	336	16	-0.1816	-0.0089
14	Monthly Charges		Meter/mo.	462	310	15	-$671.24	-$32.76
15	Customer supplied fuel		GJ	437,794	(462)	(468)	0.088%	0.089%
16	Total Transportation - T2			4,592,825	6,226	(142)		
17	Total Delivery - T2		10^3m^3	4,592,825	8,636	2,255		

Notes:
(1) Exhibit B, Tab 1, Schedule 1, Appendix C, Working Papers, Schedule 5, pp. 4-14, column (a), including preliminary rate design changes.
(2) Exhibit B, Tab 1, Schedule 1, Appendix C, Working Papers, Schedule 5, pp. 4-14, column (g).
(3) Rate class totals per Exhibit B, Tab 1, Schedule 1, Appendix C, Working Papers, Schedule 4, p. 1, column (d).

UNION RATE ZONES
Derivation of Cost Allocation Study Directive Rate Impacts

Line No.	Particulars	Billing Units	2019 Forecast Usage (10^3m^3)(1) (a)	Cost Study Including Proposals Revenue (Deficiency)/ Sufficiency ($000s)(2) (b)	Cost Study Excluding Proposals Revenue (Deficiency)/ Sufficiency ($000s) (3) (c)	Cost Allocation Study Rates Including Proposals (cents / m^3) (d)= (b / a)	Cost Allocation Study Rates Excluding Proposals (cents / m^3) (e)= (c / a)
	T3 Storage and Transportation						
	Storage ($/GJ's)						
	Demand:						
	Firm injection / withdrawal						
1	Union provides deliverability inventory	GJ/d/mo.	-	-	-	-0.769	-0.767
2	Customer provides deliverability inventory	GJ/d/mo.	679,320	210	208	-0.685	-0.683
3	Incremental firm injection right	GJ/d/mo.	-	-	-	-0.685	-0.683
4	Interruptible	GJ/d/mo.	-	-	-	-0.685	-0.683
5	Space	GJ/d/mo.	36,614,256	55	55	-0.001	-0.001
	Commodity:						
6	Commodity (Customer Provides)	GJ	4,867,885	16	16	-0.004	-0.004
7	Commodity (Union Provides)	GJ	-	-	-	-	-
8	Customer supplied fuel	GJ	19,764	(38)	(38)	0.268%	0.270%
9	Total Storage - T3		280,802	244	240		
	Transportation (cents/ m3)						
10	Demand	10^3m^3/d/m	28,200	445	(1)	-1.5784	0.0033
11	Commodity	10^3m^3	280,802	14	(0)	-0.0049	0
12	Monthly Charges	Meter/mo.	12	23	(0)	-$1,916.60	$4.30
13	Customer supplied fuel	10^3m^3	41,562	(5)	(6)	0.016%	0.017%
14	Total Transportation - T3		280,802	477	(7)		
15	Total Delivery - T3	10^3m^3	280,802	720	234		
16	Total In-Franchise Commodity / Admin		4,642,516	1,971	1,971	-0.0425	-0.0425
17	Total In-franchise			(20,654)	(20,646)		

Notes:
(1) Exhibit B, Tab 1, Schedule 1, Appendix C, Working Papers, Schedule 5, pp. 4-14, column (a), including preliminary rate design changes.
(2) Exhibit B, Tab 1, Schedule 1, Appendix C, Working Papers, Schedule 5, pp. 4-14, column (g).
(3) Rate class totals per Exhibit B, Tab 1, Schedule 1, Appendix C, Working Papers, Schedule 4, p. 1, column (d).

UNION RATE ZONES
Typical Small, Large and Average Customer Bill Impact Assumptions

Line No.	Particulars		Firm Contract Demand (m^3/d) (a)	Annual Consumption (m^3) (b)	Commodity Transportation 1 (m^3) (c)
	Union North				
1	Rate 01	Small	-	2,200	
2	Rate 10	Small	-	60,000	
3		Large	-	250,000	
4	Rate 20	Small	14,000	3,000,000	170,800
5		Large	60,000	15,000,000	732,000
6	Rate 25	Small	-	2,275,000	
7	Rate 100	Small	100,000	27,000,000	915,000
8		Large	850,000	240,000,000	7,777,500
	Union South				
9	Rate M1	Small	-	2,200	
10	Rate M2	Small	-	60,000	
11		Large	-	250,000	
12	Rate M4	Small	4,800	875,000	
13		Large	50,000	12,000,000	
14	Rate M5	Small	7,500	825,000	
15		Large	70,000	6,500,000	
16	Rate M7	Small	165,000	36,000,000	
17		Large	720,000	52,000,000	
18	Rate M9	Small	56,439	6,950,000	
19		Large	168,100	20,178,000	
20	Rate M10	Average	-	94,500	
21	Rate T1	Small	25,750	7,537,000	
22		Large	133,000	25,624,080	
23		Average	48,750	11,565,938	
24	Rate T2	Small	190,000	59,256,000	
25		Large	1,200,000	370,089,000	
26		Average	669,000	197,789,850	
27	Rate T3	Large	2,350,000	272,712,000	

ENBRIDGE GAS INC.

Answer to Interrogatory from
OEB Staff ("STAFF")

Interrogatory

Reference:

Exhibit B, Tab 2, Schedule 1, pp. 15-18

Question:

Enbridge Gas has requested incremental capital module (ICM) funding for the Don River Replacement Project. The project is needed to replace approximately 0.25 km of NPS 30 XHP on the Don River Bridge crossing with a new NPS 30 XHP under the Don River. The project was approved in the EB-2018-0108 leave to construct application. In the 2019 rates application (EB-2018-0305), Enbridge Gas requested ICM funding for the Don River Replacement Project but based on the ICM materiality threshold calculation there was no room for ICM funding in the EGD rate zone. However, the project was postponed and is now scheduled to be put into service in May 2020. The total capital cost of the project is $35.4 million which is the same as that identified in the 2019 rates application. In response to an undertaking (JT1.7) in the 2019 rates application, Enbridge Gas noted that the total indirect overhead costs allocated to the project was $9.4 million or 36.4% of the total costs.

a) Please confirm that the total indirect overheads costs are the same in 2020 as identified in JT1.7.

b) Please use the 2019 total overheads and capital projects that were allocated indirect overheads to substantiate an indirect overhead cost allocation of 36.4% for 2019 capital projects. Please provide supporting numbers to show the calculation.

Response

a) Confirmed, the total indirect overheads costs are the same as identified in Exhibit JT1.7 in the 2019 rates application.

b) The calculation is shown in the table below:

2019 EGD Rate Zone Core Capital Budget

	$ Millions
Direct Capital projects eligible for overhead	364
Departmental Labour Charge	96
Administrative & General	37
Overhead %	36.4%

ENBRIDGE GAS INC.

Answer to Interrogatory from
OEB Staff ("STAFF")

Interrogatory

Reference:

Exhibit B, Tab 2, Schedule 1, pp. 15 and 19

Question:

Enbridge Gas requested ICM funding for the Windsor Pipeline Replacement Project. The project will replace approximately 64 kms of existing Windsor NPS 10 pipeline (and some short sections of NPS 8) located in the Municipality of Chatham-Kent and County of Essex with NPS 6 pipeline operating at a pressure of 3,450 kpa. The evidence notes that the proposed pipeline is necessary to replace the existing pipeline due to integrity concerns. The total capital spend in 2020 is $91.9 million of which Enbridge Gas has requested $84.2 million in ICM funding.

a) Please provide a breakdown of the project costs including a breakdown of indirect overheads.

Response

Please see Exhibit I.VECC 6.

ENBRIDGE GAS INC.

Answer to Interrogatory from
OEB Staff ("STAFF")

Interrogatory

Reference:

Exhibit B, Tab 2, Schedule 1, p. 19

Question:

Enbridge Gas filed a leave to construct application with the OEB for the Windsor Pipeline Replacement Project on August 9, 2019 (EB-2019-0172). The application is currently before the OEB and a decision on this application has not yet been issued. In this application, Enbridge Gas has requested ICM funding for the project. The OEB's policy states that an ICM is intended to address the treatment of a distributor's capital investment needs that arise during the Price Cap IR rate-setting plan which are incremental to a materiality threshold (*Report of the Board: New Policy Options for the Funding of Capital Investments: The Advanced Capital Module, EB-2014-0129, September 18, 2014*). An ICM must meet tests for materiality, need and prudence.

a) Please explain how the OEB can approve ICM funding for the project prior to approval of the Windsor Line Replacement leave to construct application where the need and prudence of the project will be examined.

Response

a) The Board could make ICM approval for the Windsor Line Replacement Project within the 2020 Rates application conditional upon the receipt of an approval for the leave to construct application. Without leave to construct approval, there would be no Project and as such, no ICM funding will be required.

ENBRIDGE GAS INC.

Answer to Interrogatory from
OEB Staff ("STAFF")

Interrogatory

Reference:

eBilling, Exhibit B, Tab 3, Schedule 1, p. 1

Question:

Enbridge Gas changed its eBill practices in 2019 to make eBill the default billing method for new customers and to switch existing paper bill customers who, for any reason, had previously provided an email address to the Company without prior specific consent. Enbridge Gas believes that its change in practice is appropriate and does not believe that any OEB approval was or is required.

a) Please explain why Enbridge Gas is of the opinion that it does not require approval of the OEB to involuntarily switch customers from paper bills to eBills.

Response

Please see Exhibit I.VECC.23.

ENBRIDGE GAS INC.

Answer to Interrogatory from
OEB Staff ("STAFF")

Interrogatory

Reference:

eBilling, Exhibit B, Tab 3, Schedule 1, p. 4

Question:

Given customers' evolving expectations, Enbridge Gas has been working to shift as many interactions as possible away from traditional channels (i.e. phone calls, paper bills, letters) to a consumer-centric digital experience (i.e. myAccount, email, text, chat, social media). Prioritizing the use of modern channels of communication is critical to creating an optimal customer experience in line with consumer expectations, as well as driving long-term value for ratepayers by reducing Enbridge Gas's cost-to-serve.

a) Please advise if Enbridge has undertaken a consumer-focused research or consultation with consumers or consumer groups in Ontario that support these statements.

Response

Enbridge Gas did not initiate a targeted research effort on this topic. There is a wide variety of secondary research on the topic of evolving consumer expectations. Enbridge Gas serves home and business owners across Ontario whose expectations are formed by the service they receive from large brands both Canadian and international in scope.

Enbridge Gas utilitizes a voice-of-the-customer program to send surveys to customers following key transactions. The theme of customers wanting to be able to self-serve with ease through digital channels is a common one that Enbridge Gas sees in customer feedback.

ENBRIDGE GAS INC.

Answer to Interrogatory from
OEB Staff ("STAFF")

Interrogatory

Reference:

eBilling, Exhibit B, Tab 3, Schedule 1, p. 11

Question:

The evidence states that Enbridge Gas is now using sophisticated machine learning and artificial intelligence to estimate consumption in months without an actual read.

a) Please explain how Enbridge Gas uses machine learning and artificial intelligence to estimate consumption without an actual read.

b) Does Enbridge Gas have any data demonstrating positive changes to accuracy of estimated readings using the new approach? If so, please file supporting evidence.

Response

a) Enbridge Gas has removed the calculation of estimation factors from its SAP Customer Information System ("CIS"). The old technique using CIS was quite simplistic to ensure it did not negatively impact overnight batch performance of Enbridge Gas's billing routines. Calculation of estimation factors is now performed outside of SAP CIS using additional historical account-specific data regression analysis and other techniques to pick up on anomalies like pool heaters and other equipment that adversely impacts energy use.

b) Enbridge Gas is only beginning to evaluate the impact of the new approach as these changes were just implemented in Q4 2018.

ENBRIDGE GAS INC.

Answer to Interrogatory from
OEB Staff (“STAFF”)

Interrogatory

Reference:

eBilling, Exhibit B, Tab 3, Schedule 1, pp. 18-19

Question:

Within the Enbridge Gas Distribution (EGD) rate zone, 331,480 active customers with an e-mail address in Enbridge Gas’s Customer Information System (CIS) were converted to eBill over the course of 2019. In the first phase in February 2019, 147,756 customers were converted, and they received both a letter and email informing them of the switch to eBilling. Both communications made it clear that if customers wished to revert back to paper they simply needed to contact the Company via the Enbridge Gas call centre.

a) Please indicate if Enbridge Gas required customers to respond to the email sent to them informing them of the switch to eBilling in order to validate and acknowledge the receipt of the notice.

b) Please explain how Enbridge Gas ensured that the email address used for the purpose of eBilling was the primary email used by the customer and was the customer’s preferred email address.

c) Please explain the amount of notice given to customers that they would be transferred to eBilling and the rationale for determining the length of notice given.

d) Please explain Enbridge Gas’s process for transferring customers back to paper bills (e.g., are customers sent replacement paper bills or are they transferred to paper billing for their next upcoming billing period?).

e) Please explain how Enbridge Gas ensures that customers who revert back to paper billing may not be subsequently transferred to eBilling (given that their email addresses may remain on file).

Response

a) No. Enbridge Gas did not require customers to validate and acknowledge receipt of the notice. However, the notice did indicate that if the customer had any questions about the change, they could contact Enbridge Gas.

b) When a customer contacts Enbridge Gas's call centre, they are asked to provide the best contact information to get in touch with them regarding their account. Any email provided is presumed to be the best address.

c) Customers were notified by email 2-3 days prior to their first eBill in order to ensure that the notification was top of mind and customers would be looking for their next bill in their email.

d) To switch back to paper a customer must call the contact centre for an agent to change their bill preference in Enbridge Gas's system. At this time, customers are given the option to receive a paper copy of their most recent bill.

e) When a customer reverts to paper their email address is removed from the system.

ENBRIDGE GAS INC.

Answer to Interrogatory from
OEB Staff ("STAFF")

Interrogatory

Reference:

eBilling, Exhibit B, Tab 3, Schedule 1, pp. 18

Question:

In the second phase in March 2019, customers only received an email. In this phase, 103,359 customers were converted. The final phase undertaken in October 2019, with 107,269 customers being converted in the same manner.

a) Please explain the rationale for not providing a letter in addition to an email to customers in the second phase and the third (final) phase.

b) Please provide a breakdown per phase (i.e., for each of the first phase, second phase and third phase) of the number of customers who chose to revert back to paper bill.

Response

a) Enbridge Gas observed feedback from customers in the first phase to determine the approach going forward. The Company's monitoring suggested that the email was the common driver behind customer interactions and that the letter was not having a significant impact on customer activity related to conversions. Due to this limited impact the decision was made to not continue with the letter in subsequent phases.

b) The breakdown per phase is provided below. Please note that the total number of customers converted using existing email addresses in the EGD rate zone is incorrectly shown as 331,480 at paragraph 37(ii) of Exhibit B, Tab 3, Schedule 1. The number should be shown as 358,384. Enbridge Gas will file a correction to the evidence with the interrogatory response.

Switched back to paper by phase LEGD	Total Converted	Switched back	%
LEGD			
Phase 1	147756	22421	15%
Phase 2	103359	24445	24%
Phase 3	107269	26845	25%
Total LEGD	**358384**	**73711**	**21%**
LUG			
Phase 1	171905	32661	19%

ENBRIDGE GAS INC.

Answer to Interrogatory from
OEB Staff ("STAFF")

Interrogatory

Reference:

eBilling, Exhibit B, Tab 3, Schedule 1, pp. 19-20

Question:

Enbridge Gas has provided the percentage of total eBill customers by rate class for the EGD and Union Gas rate zones for 2019. The distribution of customers on eBill is skewed towards residential customers given they represent a majority of the customers for both legacy utilities.

a) Please confirm if commercial customers were also involuntarily switched to eBilling in 2019 (for commercial customers who had provided an email address to both legacy utilities).

b) Please explain the reasons for the low adoption/conversion to eBilling (1%) for Union Gas commercial customers.

Response

a) Confirmed.

b) Please see Exhibit I.QMA.5 a).

ENBRIDGE GAS INC.

Answer to Interrogatory from
OEB Staff ("STAFF")

Interrogatory

Reference:

eBilling, Exhibit B, Tab 3, Schedule 1, pp. 20-22

Question:

Given the scale of eBill transition, Enbridge Gas experienced increased call and complaint volume relating to eBilling in 2019. In 2019, Enbridge Gas received 55,949 calls in the EGD rate zone relating to eBills and 28,061 calls in the Union Gas rate zones. These figures capture all live, inbound calls related to eBill including routine questions (i.e. the figures do not represent customer complaints).

a) For each of the first, second, and third phase, please provide the total number of calls (for both EGD and Union Gas) that specifically related to customers not knowing that they have been switched to eBilling, customers that called to complain about late payment penalties related to eBills and customers who did not want eBills. Of these, how many customers were switched back to paper bills?

b) For those customers that called to complain about eBills, please provide the general themes of the complaints.

c) For each of the first, second, and third phase, please provide the number of customers with previously demonstrated good payment history, that were converted to eBills, and who subsequently:
    a. fell into arrears,
    b. received a collection notice,
    c. received a disconnection notice, and
    d. were disconnected.

d) Of those customers in c), how many called to advise they were not aware that they had been converted to eBills?

Response

a) Enbridge Gas is not able to provide the breakdown as requested. However, as per the pre-filed evidence[1], Enbridge Gas received 84,010 inbound calls related to eBill. These calls are not specific to the phases of conversion but relate to overall activity. For customers switching back to paper, please see a breakdown by phase.

	Total Converted	Switched back
LEGD Phase 1	147756	22421
LEGD Phase 2	103359	24445
LEGD Phase 3	107269	26845
Total LEGD	**358384**	**73711**
LUG Phase 1	171905	32661

b) The general themes of customer complaints are outlined below:

- Customer does not use the email address that is on file on their account
- Customer wants a paper bill
- Customer was not notified of change to eBill and missed a payment

[1] Exhibit B, Tab 3, Schedule 1, Table 4.

c)

	Total	Phase 1	Phase 2	Phase 3
(A) fell into arrears	109,742	66,380	27,967	15,395
(B) received a collection/reminder notice	109,742	66,380	27,967	15,395
(C) received a disconnection notice	3,220	1,680	1,540	-
(D) were disconnected	684	214	470	-

d) Enbridge Gas does not have sufficiently detailed data on inbound calls to determine the number of inbound calls for this specific group.

ENBRIDGE GAS INC.

Answer to Interrogatory from
OEB Staff ("STAFF")

Interrogatory

Reference:

eBilling, Exhibit B, Tab 3, Schedule 1, p. 21

Question:

In 2019, ombudsman complaints related to eBill rose to 8.5% from 1.9% in 2018 of all complaints in the EGD rate zone while in the Union Gas rate zone, ombudsman complaints increased from 0.6% in 2018 to 9% in 2019.

a) Please explain under what conditions a complaint about eBilling would be escalated to the ombudsman office. Please provide examples.

b) Please provide the general themes of the complaints about eBilling that were escalated to the ombudsman office.

Response

a) Customers can, and may, contact the customer ombudsman office directly. The customer may also be referred to the ombudsman office if they are not satisfied with the resolution offered by the contact centre.

b) The themes for complaints to ombudsman were similar to the complaints logged at the call centre. The general themes of complaints are outlined below.

- Customer does not use the email address that is on file on their account
- Customer wants a paper bill
- Customer was not notified of change to eBill and missed a payment

ENBRIDGE GAS INC.

Answer to Interrogatory from
OEB Staff ("STAFF")

Interrogatory

Reference:

eBilling, Exhibit B, Tab 3, Schedule 1, p. 23-24

Question:

Regarding customer service as measured using Net Promotor Score (NPS), the evidence in Figure 5 shows that overall customer satisfaction has significantly improved alongside implementation of Enbridge Gas's 2019 eBill practices.
Though overall customer satisfaction experienced a short-term decrease in early 2019, a number of factors influenced customers at this time as EGD and Union Gas entered the first few months of their amalgamation. In particular, the decrease in NPS shown in April 2019 was largely driven by customer confusion resulting from the rebranding of legacy Union Gas, in addition to some challenges in April and May of 2019 relating to the direction of payments to the appropriate legal entity. These temporary impacts aside, NPS has experienced a steady upward trend over the past 18 months. By the time that the 2019 eBill conversions were completed, NPS was at its highest level in the recent past.

a) Please extend the view in Figure 5 to the most recent five year period (i.e., 2015-2019) to provide context to the NPS changes seen since March 2018.

b) Please confirm if it is Enbridge Gas's position that the steady upward trend in NPS over the past 18 months is related to eBill adoption. Please provide rationale to support the position.

Response

a) Enbridge Gas only started tracking NPS using this method and channel (email survey) with the launch of the Voice-of-the-customer project in March 2018. As a result, data on NPS is not available prior to this date.

b) It is not Enbridge Gas's position that the upward trend in NPS is specifically related to eBill adoption. However, Enbridge Gas does believe that improvements to self-service and other projects implemented as part of the Customer Experience program have had a positive overall impact on NPS.

ENBRIDGE GAS INC.

Answer to Interrogatory from
OEB Staff ("STAFF")

Interrogatory

Reference:

eBilling, Exhibit B, Tab 3, Schedule 1, p. 25

Question:

Additionally, as stipulated in the Settlement Proposal, Enbridge Gas has agreed to refund Late Payment Penalty (LPP) amounts paid by customers converted to eBilling in 2019 where such customers had previously demonstrated good payment history. In the Union Gas rate zones, Enbridge Gas will refund $289,240 in LPP to customers; representing 5% of all LPP amounts paid from March through November of 2019. In the EGD rate zones, Enbridge Gas will refund $446,242 in LPP to customers; representing 4% of all LPP amounts paid over the same time period.

a) Regarding the $289,240 in LPP, please provide the total amount of arrears and the total number of customers with otherwise good payment history that this relates to.

b) Regarding the $446,242 in LPP, please provide the total amount of arrears and the total number of customers with otherwise good payment history that this relates to.

Response

a) The $289,240 was refunded across 33,948 customers. Stating the total arrears is difficult as the LPP amounts relate to a large number of accounts, some of which would have been in arrears over multiple months (with different amounts of arrears for the same account at different times).

b) The $446,242 was refunded across 60,370 customers. Stating the total arrears is difficult as the LPP amounts relate to a large number of accounts, some of which would have been in arrears over multiple months (with different amounts of arrears for the same account at different times).

ENBRIDGE GAS INC.

Answer to Interrogatory from
OEB Staff ("STAFF")

Interrogatory

Reference:

eBilling, Exhibit B, Tab 3, Schedule 1, p. 25-26

Question:

The cost difference between paper billing and eBilling is approximately $10 per customer per year. As Enbridge Gas continues to transition customers to eBill, Enbridge Gas's total postage budget will continue to decrease, however this expenditure remains significant at over $15 million annually.

Both EGD and Union began offering eBill options over ten years ago. Taking into account present day bill production and postage costs, Enbridge Gas estimates the total bill production budget including postage absent eBilling would be close to $45 million annually. Having now reached 58% eBill adoption, the current combined cost of paper and digital bill delivery is approximately $28 million annually, resulting in savings of approximately $17 million on this item alone.

a) What was the combined cost of paper and digital bill delivery / savings when eBill adoption was at 40% (December 2018).

Response

The combined cost of paper and digital bill delivery when eBilling adoption was at 40% was approximately $27.5 million.

Enbridge Gas notes two corrections that need to be made to the pre-filed evidence at paragraph 53. The current combined cost of paper and digital bill delivery shown as $28 million should be shown as $21 million. The total cost absent eBilling shown as $45 million should be shown as $42.5 million. Enbridge Gas will file a correction to the evidence with the interrogatory response.

ENBRIDGE GAS INC.

Answer to Interrogatory from
OEB Staff ("STAFF")

Interrogatory

Reference:

Exhibit C, Tab 1, Schedule 1, Appendix A: EGD Asset Management Plan, section 5.4.15.2 and Wells Upgrade, Business Case ID: 6376

Question:

Wells at Crowland are much older than other wells. Due to age, the wells were constructed to a production standard which would normally be retired after 10 years. Instead the wells were converted to storage service in the early 1970's and continue to operate ever since. Many wells have been relined, increasing the risk of leaks. Most wells possess only two casings – the current standard requires a minimum of three, and also do not possess a suitable master valve and wellhead. Replacement of well assets at Crowland is expected to be a significant capital request within the scope of the 10-year Asset Management Plan.

In response to OEB staff interrogatory #53 in EB-2018-0305, Enbridge Gas indicated that the total costs related to upgrade and maintenance of Crowland wells and field lines is $11,648,000 and $3,457,000 respectively. Station upgrades are not included in the maintenance capital portfolio, because the scope and cost are unclear. An updated financial assessment will be completed in 2019 when additional information is available.

a) Please confirm if the updated financial assessment has been completed and please provide the outcome of the financial assessment including updated costs.

b) What is the total storage capacity of the Crowland wells?

c) In OEB staff interrogatory #53 (EB-2018-0305), Enbridge Gas indicated that additional analyses of various options to manage Crowland were underway. Please confirm if the additional analyses has been completed and provide the results of the analyses.

d) Considering that the amalgamated utility has significant storage, has Enbridge Gas considered other options such as abandoning the Crowland wells? If no, why not?

Response

a) The updated financial assessment has not yet been completed. The scope of work at the site is currently under review and Enbridge Gas is striving to have the associated costs updated as part of the 2021 budget and AMP update process. As seen in the Wells Upgrade, Business Case ID: 6376 noted in the question, the most recent AMP forecasts that the wells upgrade project will not commence until 2024.

b) The storage capacity of the Crowland pool is 8,100 10^3m^3.

c) Further testing is required to determine the optimal long-term solution for the Crowland assets. Enbridge Gas is currently in the process of operational testing of the facilities to better understand their performance. Enbridge Gas is testing the assets to understand the future need for compression at the site.

d) Enbridge Gas continues to see strong demand for incremental storage services. Abandoning of the Crowland wells is not the preferred option at this time, the pool itself provides value to the local operation that cannot be replaced with incremental storage space at Dawn.

ENBRIDGE GAS INC.

Answer to Interrogatory from
OEB Staff ("STAFF")

Interrogatory

Reference:

Exhibit C, Tab 1, Schedule 1, Appendix A: EGD Asset Management Plan, Section 5.8 – Technology and Information Services

Question:

The Technology Information Services (TIS) asset class includes the hardware, software and communications subclasses. Software assets consist of packaged applications (purchased from and generally supported by a vendor), developed applications (custom built in-house) and application infrastructure software.

In response to OEB staff interrogatory 67 in EB-2018-0305, Enbridge Gas indicated that it had not yet completed a detailed review of the EGD and Union Gas rate zones' Information Technology (IT) business applications. The plan is currently under development and is expected to be completed by the end of 2019.

a) Please confirm if the review of EGD and Union Gas's IT business applications is complete. If the review has been completed, please provide the outcome. If not, please provide reasons for the delay.

b) Has Enbridge Gas changed or modified any of its planned capital expenditures with respect to IT business applications based on the outcome of the review? If yes, please identify the changes. If there are no changes to the planned capital expenditures, please provide reasons.

Response

a) A review has been completed and will be an ongoing process as more information becomes available to address the business priorities of the company. The Enbridge Gas Asset Plan Addendum reflects pre-integration planning, and further review has led to changes in the TIS capital portfolio.

b) Yes. Changes have been made to align with business priorities. Sequencing has been adjusted to reduce execution risk and deliver the greatest value to the company and our customers.

For legacy EGD, adjustments were made to the portfolio, however there is little change to the total TIS capital expenditures. The addendum total amount was $15.145 million and it now $15.762 million. There was approximately $7 million that shifted within the portfolio, in most cases it was the creation of specific projects rather than forecast program spends, plus the advancement of meter hand held replacements and a reduction in WAMS enhancement releases. The cost pressures driving the increase are being managed through the Asset Management process.

For legacy Union, there was a net reduction of $8.5 million in total TIS capital expenditures as integration investments were removed from the budget. The TIS capital expenditure total has been reduced from $30.955 million to $22.45 million. Please see the table below for the major drivers of this reduction. The reduction in TIS spending is offset by the advancement of the replacement of the Hamilton Gate Station ($6 million) and relocation work related to London Rapid Transit ($5.2 million).

Legacy UnionTIS Investment changes	AMP Capital Cost (2020) $ millions	Revised Capital Cost (2020) $ millions	Difference $ millions
Banner enhancements	2.076	0.500	(1.576)
Energy Services integration	6.326		(6.326)
Business support for amalgamation	2.025	0	(2.025)
Emergency Service Address Listing	0.155	0	(0.155)
USR Toughbooks Lifecycle	2.874	4.027	1.153
Subtotal	13.456	4.527	(8.929)

The dynamic process by which the portfolio of projects is managed through the year is described in Exhibit I.VECC.10. The specific examples of emerging risks and cost pressures in the Union rate zone are identified in Exhibit I.EP.5.

ENBRIDGE GAS INC.

Answer to Interrogatory from
OEB Staff ("STAFF")

Interrogatory

Reference:

Exhibit C, Tab 1, Schedule 1, Appendix B: Union Gas Rate Zones Asset Management Plan, section 2.6, p. 194

Question:

Minimum Operating Pressure (MOP) verification is the process of reviewing all existing records for a pipeline system and confirming the maximum operating pressure of pipelines that are greater than 30 percent SMYS. While this is not currently mandated by code in Canada, it is required in the United States and is expected to become a requirement in Canada in the future. Given that Union Gas has approximately 2,980 km of pipelines greater than 30 percent SMYS, MOP verification will be a multi-year project requiring a dedicated team to complete the verifications and determine if any pipeline remediation is required. The intent of the MOP verification program is to spread the verifications over several years to keep costs down and mitigate the need for higher expenditures in a shorter time frame to meet these expected future mandated requirements.

a) In EB-2018-0305, Enbridge Gas indicated (OEB staff IR#65) that it does not know when the verification will become a requirement in Canada. Please indicate if Enbridge Gas has updated information on when MOP verification will become a requirement in Canada.

b) The total capital expenditure for this program is $30 million from 2023 to 2028. Please explain why ratepayers should pay for a verification program that is not yet a requirement in Canada.

c) Does Enbridge Gas intend to proceed with the verification program if it does not become a requirement by 2023? Please explain your response.

d) In response to OEB staff IR#65e (EB-2018-0305), Enbridge Gas indicated that if the verification program is implemented in Canada, the Canadian authorities will give sufficient time to utilities to implement the verification process. Please explain why

Enbridge Gas cannot defer the implementation of the program until it becomes a requirement in Canada.

Response

a) Enbridge Gas does not have any updated information on when MOP Verification will become a requirement in Canada.

b) MOP Verification Programs are a regulated requirement in the United States with drivers directly tied to the San Bruno incident. MOP Verification Programs are fundamentally tied to safety and operational reliability through their relation to Integrity Management and having an Integrity Management Program is a regulated requirement in Canada. MOP Verification Programs can underpin Integrity Management by ensuring Operators are able to validate that they have included all required Pipelines in their respective Integrity Management Programs and can demonstrate their fitness for service. In this way, MOP Verification Programs provide value, whether they are a regulated requirement or not.

c) Through the integration of Enbridge Gas Distribution and Union Gas, Enbridge Gas has leveraged the existing MOP Verification program at Legacy Enbridge Gas Distribution and has begun MOP Verification Assessments on Legacy Union Gas Assets which is anticipated to result in capital requirements as early as 2023. Enbridge Gas does however fully expect that this work will continue to be prioritized and reviewed from a pacing perspective on an annual basis.

   As noted in EB-2018-0305 Exhibit I.STAFF.65 part d), Enbridge Gas views this work as a priority from a safety and operational reliability perspective. Within part e) Enbridge Gas notes that taking a proactive approach allows Enbridge Gas to spread out the required costs in alignment with customer preferences for steady pace of spend and allows for more flexibility than that of a regulated period of compliance.

ENBRIDGE GAS INC.

Answer to Interrogatory from
OEB Staff ("STAFF")

Interrogatory

Reference:

Exhibit C, Tab 1, Schedule 1, Appendix B: Union Gas Asset Management Plan, section 4.1, p. 205

Question:

Dawn C Plant is one of the nine centrifugal compressors located at the Dawn Compressor Station. Siemens, the original equipment manufacturer of the Dawn C compressor, has indicated that 40 years is the typical timeframe over which they support supply of engine parts required to recover from a critical engine failure or to complete recommended overhauls. Dawn Plant C was installed in 1984 and the RB211-24A engine is reaching end of life. The engine has non-standard dimensions and cannot be retrofitted with more modern editions of the RB-211 without significant plant retrofits. As the entire plant is out of specification in terms of the new standard compressor station designs, it is recommended that Plant C be replaced in its entirety. The cost of a new RB211 DLE plant is estimated at $155.9 million. Design is proposed to begin in 2022 with an in-service date of 2024 and abandonment of the obsolete Plant C structures in 2025.

a) Please provide the total estimated cost of the project including the new engine, installation, new structures and cost of existing engine removal and abandonment of Plant C structures.

Response

The cost estimate of $155.9 million is currently based on a 2017 class 5 estimate that will be updated this year. The cost estimate of $155.9 million includes the new engine, installation, new structures and cost of existing engine removal and abandonment of Plant C structures.

ENBRIDGE GAS INC.

Answer to Interrogatory from
OEB Staff ("STAFF")

Interrogatory

Reference:

Exhibit C, Tab 1, Schedule 1, Appendix B: Union Gas Asset Management Plan, section 9.1, p. 255

Question:

The legacy Union Gas uses a Banner Enlogix customer information system (CIS) to provide billing services for 1.4 million non-contract general use customers. The software was implemented across Union Gas in 2000. Banner is the system of record for customer, premise, account, service and meter information, and all related processes. Enbridge Gas has planned capital expenditures to enhance certain services and implement a major life cycle replacement from 2024 through to 2027.

a) Please indicate if the legacy EGD and Union Gas intend to operate separate CIS for the foreseeable future (2025 and beyond).

b) Has Enbridge Gas considered integrating the CIS for the EGD and Union Gas rate zones? If no, why not?

c) Please explain why Enbridge Gas intends to implement a major life cycle replacement of the Union Gas CIS starting in 2024 considering that it has sufficient time until 2024 to consider and implement a common CIS platform across the legacy utilities.

Response

a) No. Enbridge Gas plans to amalgamate the two existing CIS systems into one by the end of 2021.

b) Yes. Please see the response to part a)

c) This is no longer the case, due to the decision to implement a common CIS platform across the legacy utilities.

ENBRIDGE GAS INC.

Answer to Interrogatory from
OEB Staff ("STAFF")

Interrogatory

Reference:

Exhibit C, Tab 1, Schedule 1, Appendix B: Union Gas Asset Management Plan, section 9.3, p. 257

Question:

The Construction Administration Records Systems (CARS) application is a legacy Union Gas application used to manage construction work orders used for new customer service lateral attachments. This application consists of an internally based application, an Internet facing application (GetConnected) as well as the business to business component. It was developed in-house in 2009. The underlying technologies are aging and it is becoming increasingly difficult to enhance and support the application. The evidence states that Union Gas intends to consider an off-the-shelf solution rather than custom-built solutions as part of the lifecycle projects. The total capital expenditure for the project is $27.9 million. During 2021 to 2024, CARS will have a major lifecyle replacement to ensure it continues to operate effectively.

a) Are effective off-the-shelf solutions available to replace CARS?

b) What software application is currently used by the legacy EGD to manage construction work orders and perform similar functions as CARS?

c) Is the legacy EGD software a custom-built solution or an off-the-shelf product and when is it expected to undergo a major lifecycle replacement?

d) Has Enbridge Gas considered a common application to manage construction work orders and related processes for the legacy EGD and Union Gas rate zones? If no, why not?

e) Has Enbridge Gas reviewed all software applications that are expected to undergo a major lifecycle replacement in the next three years and planned to harmonize the replacement software applications across the legacy EGD and Union Gas rate zones? If yes, please provide a detailed response including results of the review. If not, please indicate when such a review will be completed?

Response

a) to c) Please refer to the response for to part d).

d) The legacy EGD equivalent to CARS is the Work and Asset Management Solution (WAMS), which is comprised of a number of off-the-shelf products. Both legacy utilities will be migrated to one solution as part of the Enbridge enterprise Unify project. The Enbridge enterprise Unify project will align all business units, including Enbridge Gas, to a common suite of applications for finance, supply chain and work and asset management. This will include work and asset management functions in use today at Enbridge Gas, including construction work orders.

e) Enbridge Gas has reviewed and prioritized a subset of applications which will have significant impact and/or benefits for the utility and there are now plans and work in place to harmonize the following specific applications: CIS, Maximo and Oracle. No major application lifecycle refreshes are currently planned for the next three years other than those planned integration activities being done through integration capital. Please see Exhibit I.Staff.20. As such, Enbridge Gas does not expect expenditure on the CARS application in 2021 to 2024. Enbridge Gas will be revising its planned investments from 2021-2030 and submitting details as part of the 10-year consolidated asset plan which will be submitted with the 2021 Rates Application.

ENBRIDGE GAS INC.

Answer to Interrogatory from
OEB Staff ("STAFF")

Interrogatory

Reference:

Exhibit C, Tab 1, Schedule 1, Appendix C: List of EGD Rate Zone Business Cases, ID: 10088 and ID:1796

Question:

Enbridge Gas has provided a business case to replace vintage steel main from Cherry street to Bathurst in Toronto. The project is scheduled for replacement in 2021. Two options were identified with the same risks and Lifetime Risk Return on Investment (LRROI). The cost for option 1 is approximately $150 million and for option 2, the cost is $165 million. Enbridge Gas has selected option 2 but has not provided any reasons for selecting the more expensive option.

Similarly, for the Brampton Operations Centre alterations, Enbridge Gas has selected the more expensive option to add a 9,000 square foot expansion to the existing building. In this case option 1 was selected which is estimated to cost $9.325 million with a LRROI of 74. Option 1 is estimated to cost $8.240 million and has a higher LRROI at 84.

a) Please explain why Enbridge Gas has selected option 2 for the vintage steel main replacement (Cherry to Bathurst) considering that both options have similar risk mitigation (number of customers at risk) and LRROI.

b) Please explain why Enbridge Gas has selected option 1 for the Brampton Operations Centre alterations considering that option 2 has the same risk mitigation but lower capital costs and higher LRROI.

Response

a) Option 1 and option 2 for the main replacement (Cherry to Bathurst) project have the same solution and reflect cost estimate updates. They are not actually two different options. The cost estimates differ because they were developed at different points in time. The “option 1” cost estimate was a high-level estimate calculated in May 2017. At the time, total costs were forecast at $176 million (including an estimate for cost of retirement at 15% of total project costs, which equates to a total of $150 million for direct project costs). For “option 2” (again, the same solution), the cost estimate was revised to a Class 4 estimate in June 2019. This revision resulted in forecast project costs of $168 million (including $2.8 million estimate for cost of retirement and therefore $165 million in direct project costs). In other words “ option 1” should have had the cost estimate revised instead of presenting the updated cost estimate as a separate “option 2”. This occurred due to system changes related to budgeting.

The LRROI for the two “options” (i.e., revised cost estimates for the same solution) are different, however this difference is di minimis. The system optimization not permitted to do a comparison of the “options” because, as noted, above there was only one option to consider with different cost estimates prepared at different points in time.

b) The business case for the Brampton Operations Centre Alterations (Business Case 1796) was completed several years ago, and the work on the project began around 2016. Option 1 has been chosen and is in execution. The costs for Option 1 have increased since the time that the original choice was made and work was commenced, and this is what makes the LROI lower (as can be seen in the earlier business case (Business Case 1796 attached to the 2019-2028 Asset Plan, Exhibit C, Tab 1, Schedule 1, the LROI for Option 1 was lower when the choice was made, and the costs that would have been associated with Option 2 have not been updated since that option was not chosen). The increase in costs for the chosen Option 1 is due to the split of the interior and exterior works into separate phases allowing for continued operations during construction. The completed first phase of execution was exterior site improvements. The second phase will renovate and expand the current building to meet physical and functional needs.

ENBRIDGE GAS INC.

Answer to Interrogatory from
OEB Staff ("STAFF")

Interrogatory

Reference:

Report on Unaccounted for Gas (UFG), p.6

Question:

The report provides a figure (2A) showing the breakdown of primary sources of UFG for the legacy Union Gas rate zones. The largest contributor to UFG is unknown or unexplained.

a) Please confirm that the figure shows the breakdown for both the Union South and Union North rate zones.

b) The Unknown/Unexplained is the largest contributor to UFG. Please explain if any additional information was sought by ScottMadden on this issue or if there was any additional analysis conducted to understand the unknown/unexplained sources of UFG.

c) Please explain why the report does not believe that further investigation is required to understand the largest contributor (unknown/unexplained) to UFG.

Response

a) Figure 2A on page 6 of the Report on Unaccounted for Gas reflects UFG sources for both the southern and northern operating areas of legacy Union Gas.

b) ScottMadden's approach was to identify and quantify those sources of UFG generally found in the industry. The Report reflects information and data collected from legacy Union Gas and legacy EGD on the sources of UFG. The Report notes on page 18 that it can be challenging to identify all sources of UFG that would provide for a comparison across gas utilities. Specifically, NRRI states:

> …it is not a straightforward task to measure LAUF [Lost and Unaccounted for] gas. Even after adjusting for measurable factors, uncertainty prevails over the precision of those measurements. LAUF gas has a “black box” element that makes it difficult for state commissions to quantify the effect of individual sources.[1]

As a result, some of the unknown and unexplained may be estimation variances within those sources that have been identified and quantified. Enbridge Gas has an ongoing process to identify and standardize practices to better monitor and manage UFG across the legacy Companies. The Report recommends periodic investigations into the sources of UFG, including unknown and unexplained.

c) The Report states that further investigation is needed into all sources of UFG, including the unknown and unexplained. Please refer to the conclusions on page 9. The reason to investigate all sources is that some of the unknown and unexplained may be estimation variances within those sources that have been identified and quantified.

[1] National Regulatory Research Institute (NRRI), Lost and Unaccounted-for Gas: Practices of State Utility Commissions, Ken Costello, June 2013, Executive Summary, page v

ENBRIDGE GAS INC.

Answer to Interrogatory from
OEB Staff ("STAFF")

Interrogatory

Reference:

Report on Unaccounted for Gas (UFG), p.9

Question:

Based on the report findings, ScottMadden has made certain recommendations.

a) Does Enbridge Gas intend to implement all the recommendations of ScottMadden? Please provide a detailed response including any timelines for implementation.

Response

Enbridge Gas intends to implement all of the recommendations of ScottMadden but no formal timeline has yet been established. Enbridge Gas continues to identify best practices in all areas of operations (including those related to UFG) and is committed to better monitor and manage UFG. Enbridge Gas expects to report on implementation progress in its 2022 Rates filing.

ENBRIDGE GAS INC.

Answer to Interrogatory from
OEB Staff ("STAFF")

Interrogatory

Reference:

Report on Unaccounted for Gas (UFG), p.16

Question:

The report indicates that over the past 10 years the legacy companies (Union Gas and Enbridge Gas Distribution) demonstrated lower UFG levels than any group of U.S. and Canadian gas utilities reviewed by ScottMadden. Specifically, the UFG levels for legacy Union and legacy Enbridge Gas Distribution (EGD) averaged, respectively, 0.31 percent and 0.81 percent of total sendout.

a) Did the report try to further investigate or explore the reasons for the lower UFG levels in the Union Gas rate zone versus the EGD rate zone? If no, please explain why.

b) Please explain why the UFG level for the Union Gas rate zone is lower than EGD considering that the franchise area for Union Gas is much larger than EGD.

c) What measures will Enbridge Gas adopt to ensure that the UFG level of EGD is closer to or lower than the legacy Union Gas rate zone?

Response

a) ScottMadden's primary focus was to compare legacy Union Gas and legacy EGD's practices and initiatives to monitor and manage UFG to those in the industry (rather than to one another). The Report notes on page 18 that it can be challenging to identify all sources of UFG that would provide for such a comparison across gas utilities. Specifically, the NRRI report states:

> …it is not a straightforward task to measure LAUF [Lost and Unaccounted for] gas. Even after adjusting for measurable factors, uncertainty prevails over the precision of those measurements. LAUF gas has a “black box” element that makes it difficult for state commissions to quantify the effect of individual sources*”*[1]

b) ScottMadden’s focus was related to comparing legacy Union and legacy EGD to the industry UFG rather than comparing legacy Union and legacy EGD UFG. There are many factors that might explain the UFG differences between the legacy utilities but ScottMadden didn’t specifically examine that question. It should be noted that the scope of infranchise systems being examined are different between Union (which includes transmission and storage, with an overall much larger volume/throughput) and EGD (which has minimal in-franchise transmission and storage). Additionally, differences in UFG may be the results of variations in facilities, systems, processes and procedures. For example, the age and composition of the distribution system may create variations in UFG across gas utilities. Enbridge Gas has an ongoing process to identify and standardize practices to better monitor and manage UFG across the legacy Companies.

c) Enbridge Gas intends to follow up on the recommendations that ScottMadden provided in their UFG report including identifying and standardizing best practices to monitor and manage the sources of UFG, documenting UFG data and processes, investigating the sources of UFG on a periodic basis and implementing, as appropriate, new practices and initiatives to better monitor and manage UFG. Enbridge Gas expects to report on implementation progress in its 2022 Rates filing.

[1] National Regulatory Research Institute (NRRI), Lost and Unaccounted-for Gas: Practices of State Utility Commissions, Ken Costello, June 2013, Executive Summary, page v

ENBRIDGE GAS INC.

Answer to Interrogatory from
OEB Staff ("STAFF")

Interrogatory

Reference:

Report on Unaccounted for Gas (UFG), pp. 20-21

Question:

Figures 8 and 9 provide a breakdown of the sources of UFG for the legacy Union Gas and EGD rate zones.

a) The largest contributor to UFG for EGD is Gate Station Meter Variation. Please explain the significant variance in the contribution of Gas Station meters to UFG for EGD versus the Union Gas rate zone (0.33% for EGD versus 0.01% for Union Gas).

b) What steps does Enbridge Gas intend to implement to reduce the contribution of Gas Station meter variation to UFG for the EGD rate zone?

Response

a) Please see Exhibit I.EP.24 c).

b) Please see Exhibit I.FRPO.17 a) for discussion of how Enbridge Gas is addressing potential issues at the Victoria Square gate station.

ENBRIDGE GAS INC.

Answer to Interrogatory from
OEB Staff ("STAFF")

Interrogatory

Reference:

Report on Unaccounted for Gas (UFG), pp. 24-27

Question:

The report provides data for fugitive emissions and natural gas leaks for the legacy Union Gas and EGD rate zones that is submitted to Environment Canada (figures 11 and 12). Although leaks and fugitive emission has reduced for the Union Gas rate zone, from approximately 17 10^6m^3 in 2015 to 8 10^6m^3 in 2018, there is no measurable reduction in the EGD rate zone during this period.

a) Please explain how Union Gas has succeeded in reducing natural gas leaks and fugitive emissions while EGD has not been able to achieve similar outcomes.

b) What measures does Enbridge Gas intend to implement to ensure that natural gas leaks and fugitive emissions are significantly reduced for the EGD rate zone. Please provide a detailed response including estimated timelines and target reductions.

Response

a) The reduction in fugitive emissions for legacy Union Gas is primarily due to a methodology change for the fugitive emissions calculation for storage and transmission operations. In 2015, the fugitive emissions from storage and transmission operations were estimated using industry standard default component counts and emission factors. In 2018, the calculation methodology utilized site specific data collected from the annual leak surveys completed at compressor stations.

   The same methodology change was implemented for the calculation of fugitive emissions for the legacy EGD service area. Impacts of the methodology change for the EGD rate zone would not be shown in the Scott Madden report because the volumes considered for the EGD rate zone for UFG purposes do not include storage injections and withdrawals from the Dawn/Tecumseh operations as those are upstream of the franchise area.

Furthermore, during the time period in question, the alignment of the legacy Union Gas transmission station types with industry station types was improved and the resulting emission factors being utilized in the emissions estimates have been adjusted, resulting in a decrease in associated fugitive emissions. This was not necessary for legacy EGD.

Additionally, the use of updated emission factors and improved activity factors for quantifying emissions due to customer meter sets has also led to a reduction in the estimated fugitive emissions for legacy Union Gas. These changes are planned to be implemented for the 2019 reporting year for legacy EGD along with further updates to industry emission factors.

b) As outlined in part (a), the primary contributor to the reduction in fugitive emissions for legacy Union Gas was a methodology change for the fugitive emissions calculation for storage and transmission operations. It is expected that fugitive emission estimates for storage and transmission operations will continue to decline due to an increase in the frequency of leak surveys (2020) and increased efforts focused on leak repair (2019) within both the Union and EGD rate zones. Note, however, that this will not have a significant impact on in-franchise UFG for EGD rate zone (since there is limited storage and transmission within the franchise).

ENBRIDGE GAS INC.

Answer to Interrogatory from
OEB Staff ("STAFF")

Interrogatory

Reference:

Report on Unaccounted for Gas (UFG), p. 43

Question:

With respect to company use of natural gas, the report found that Enbridge Gas has an ongoing effort to identify and standardize "best practices" across the legacy companies.

a) Please describe the "best practices" and the measures in place to implement these best practices across legacy Union Gas and EGD.

Response

The referenced section of the UFG report describes the practices and initiatives taken to monitor and manage company use as a potential (and very small) source of UFG.

Enbridge Gas will continue to examine best practices to monitor and manage the sources of UFG, including company use. Company use is not a significant source of UFG at Enbridge Gas[1] but efforts will continue to ensure that the measurement and accounting of company use is accurate and complete.

[1] See Report on Unaccounted for Gas, Figure 8 (page 20) for Legacy Union Gas sources of UFG and Figure 9 (page 21) for Legacy EGD sources of UFG.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Association of Power Producers of Ontario ("APPrO")

Interrogatory

Reference:

Exhibit B Tab 1 Schedule 1 Appendix C

Preamble:

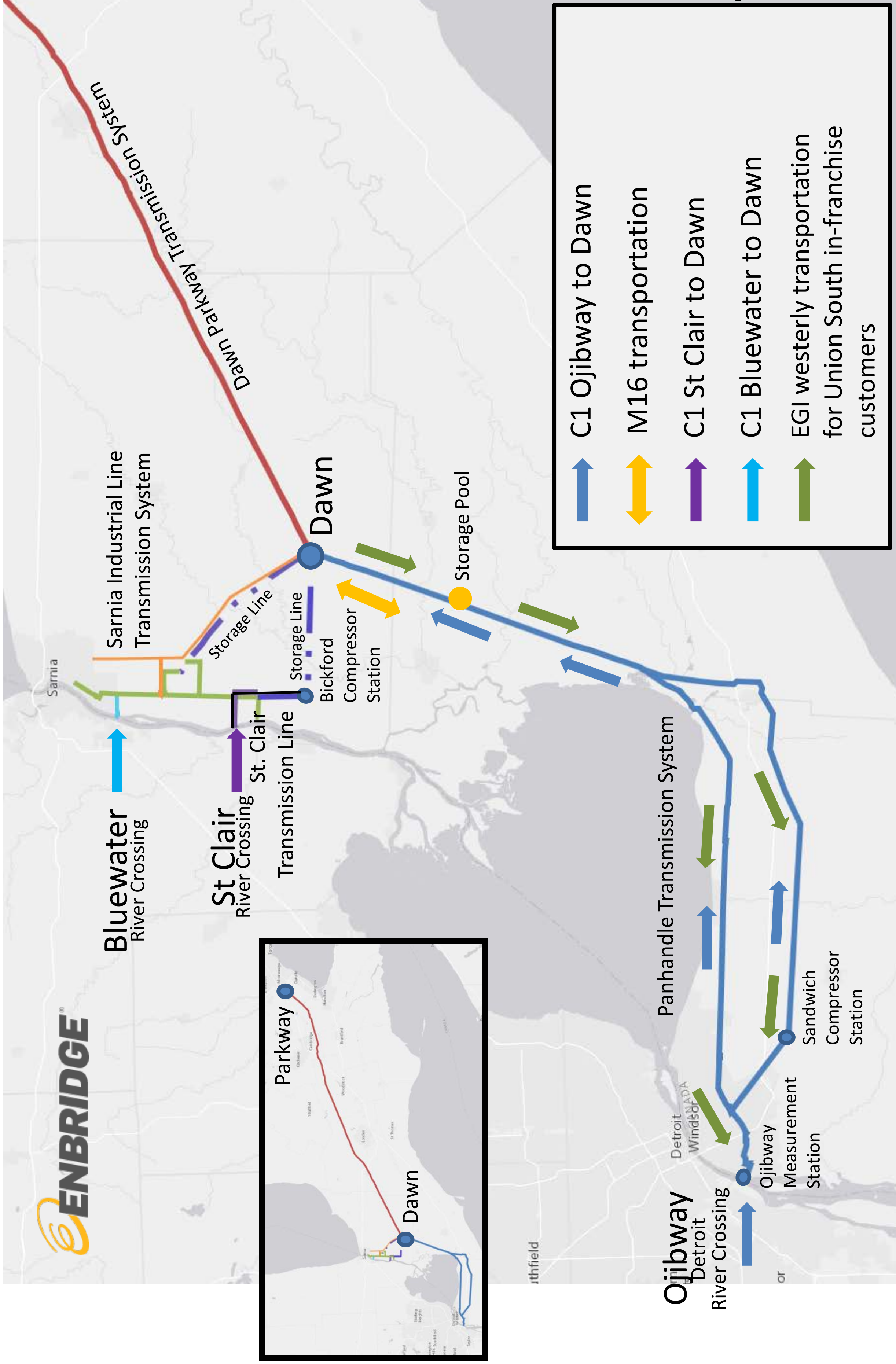
Enbridge discusses the individual systems that were the subject of the cost allocation study. To account for certain major capital projects, Enbridge Gas is seeking Board approval of cost allocation methodology changes to the Panhandle System and St. Clair System, Parkway Station and Dawn Station.

Question:

a) Please provide a map for each system that clearly illustrates the assets that are subject to the cost allocation study and how such assets integrate into the surrounding assets.

Response

Please see Attachment 1, which shows the Panhandle and St. Clair System (as well as Dawn Station and Parkway Station).


ENBRIDGE
C1 Ojibway to Dawn
M16 transportation
C1 St Clair to Dawn
C1 Bluewater to Dawn
EGI westerly transportation for Union South in-franchise customers
Dawn Parkway Transmission System
Dawn
Storage Pool
Sarnia Industrial Line Transmission System
Storage Line
Storage Line
Bickford Compressor Station
Sarnia
Bluewater
River Crossing
St Clair
River Crossing
St. Clair Transmission Line
Panhandle Transmission System
Sandwich Compressor Station
Ojibway Measurement Station
Ojibway
Detroit
River Crossing
Detroit
Windsor
Parkway
Dawn

ENBRIDGE GAS INC.

Answer to Interrogatory from
Association of Power Producers of Ontario ("APPrO")

Interrogatory

Reference:

Exhibit B Tab 1 Schedule 1 Appendix C Table 1

Preamble:

In Table 1, Enbridge provides a summary of the results of the 2019 cost allocation study directive using Board-Approved cost allocation methodologies and the proposed cost allocation methodologies provided in response to the Board's directive and as described in this evidence.

Enbridge proposes to defer the implementation of the cost allocation study until 2024. APPrO would like to understand the average customer impacts of the net revenue deficiency/sufficiency if the Board was to order Enbridge to instead implement the results of the proposed cost allocation methodology in the test year.

Question:

a) Please provide an estimate of the difference in the annual costs for an average customer within each rate class as noted in Table 1, using the current rates and an estimate of the rates that would result if the Board were to require Enbridge to incorporate the proposed new revenue deficiency/sufficiency as noted in Table 1.

b) Please provide an estimate of the difference in annual costs for a T2 customer who has contracted for 3,000,000 m^3/d of capacity, using the current rates and an estimate of the rates that would result if the Board were to require Enbridge to incorporate the proposed new revenue deficiency/sufficiency as noted in Table 1.

c) Similarly for a M12 customer, please provide an estimate of the annual cost impact to a customer who has contracted for 120,000 GJ/d of capacity under current rates, and an estimate of the rates that would result if the Board were to require Enbridge to incorporate the proposed new revenue deficiency/sufficiency as noted in Table 1.

d) Please indicate if the annual costs noted in b) and c) above are reasonably linear for customers with more or less capacity under contract. If not, please explain clearly why not.

Response

a) Please see Exhibit I.STAFF.4 part c).

b) The estimated annual impact for a Rate T2 customer that has contracted for 3,000,000 m^3/d of capacity is a bill decrease of approximately $0.7 million based on current approved 2020 Rates and the cost allocation study including proposals. The bill impact was calculated using a load factor of 50% and does not include impacts related to storage. Please see Exhibit I.STAFF.4 part c) for the assumptions used in calculating bill impacts and Attachment 3 of the same response for the unit rate changes used in the calculation of the Rate T2 bill impact.

c) The estimated annual impact for a Rate M12 customer that has contracted for 120,000 GJ/d of Dawn-Parkway transportation capacity is a bill decrease of approximately $0.4 million based on current approved 2020 Rates. Please see Exhibit I.TCPL.1, Attachment 1, column (f) for the unit rate change used in the calculation of the Rate M12 bill impact.

d) For Rate T2, the annual costs are not linear and vary for each customer based on the proportionate level of the monthly charge, contract demand and annual volumetric usage. Enbridge Gas has prepared estimated bill impacts for small, average and large Rate T2 customers at Exhibit I.STAFF.4 part c).

For Rate M12, the annual demands costs are linear based on the level of contract demand for each transportation service option. The annual fuel costs are also linear based on volumetric usage.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Association of Power Producers of Ontario ("APPrO")

Interrogatory

Reference:

Exhibit B Tab 1 Schedule 1 Appendix C Section 3.1
EB-2016-0186 Exhibit B.FRPO.6 c)

Preamble:

In paragraph 28 of Reference i) Enbridge states that the C1 capacity on the Panhandle System is only being allocated for 214 days of the year, since during the winter months the imported gas is being used in the Windsor market. APPrO would like to better understand the rationale behind this logic.

Question:

a) Please confirm that the Panhandle System includes:
   i. a transmission main between the international border and Ojibway
   ii. a transmission main between Ojibway and Dawn
   iii. Sandwich Compressor Station, metering and other station piping.

If not confirmed, please explain.

b) Please provide the maximum import capability at Ojibway.

c) Please provide a list of the C1 import contracts at Ojibway, the respective contract capacities and the contractual delivery point. Please indicate if the sum of these capacities were used to allocate costs to C1, or if some other capacity was used.

d) Please confirm that for the contracts noted in c) above that Enbridge is obligated during the term of the contract to deliver gas to Dawn or another delivery point on a firm basis each day of the contract not just during the summer months.

e) Please provide the amount firm capacity that is used by Enbridge to secure system gas supplies imported at Ojibway.

f) Please explain if these system gas supplies imported at Ojibway attract any costs in the cost allocation methodology. Please explain why, or why not, and quantify the specific costs (if any).

g) Please provide the import capacity that is being used to allocate costs to C1. Please explain any differences between this capacity and the capacity referred to in Reference ii) and in the response to b) above.

h) Enbridge does not appear to explicitly indicate if the costs of the transmission mains between the international border and Ojibway are directly allocated to C1, as is done with the St. Clair and Bluewater pipelines. Please explain if such costs are directly allocated, and if not, why

<u>Response</u>

a) Confirmed.

b) The maximum imports Enbridge Gas can accept at Ojibway from PEPL is 210 TJ/d which is limited by a Presidential Permit. The maximum amount of Ojibway to Dawn C1 transportation capacity that Enbridge Gas guarantees (firm receipts at Ojibway) is 140 TJ/d in the winter and 115 TJ/d in the summer less the amount of capacity being utilized by gas supply deliveries (58 TJ/d). The remaining capacity can be sold on a short-term (daily, monthly) discretionary basis when; 1) the market demand is greater in the Windsor area, and 2) short term capacity is available on the PEPL system.

c) The following forecasted Rate C1 import contracts and system supply attracting the Rate C1 Ojibway to Dawn rate were used in the cost allocation study:
   - Rover Pipeline LLC – 36,927 GJ/d (Dawn delivery point)
   - System Supply (from Emera Energy LP and PEPL at Ojibway) – 58,028 GJ/d (Dawn delivery point)

   Enbridge Gas confirms the forecasted contracted capacity total of 94,955 GJ/d was used in the allocation of costs to Rate C1.

d) Confirmed.

Enbridge Gas has contracted for 58,028 GJ/d of firm capacity to secure system gas supplies imported at Ojibway.

e) As described in part c), the system gas supplies imported at Ojibway are included in the allocation of costs to Rate C1. Enbridge Gas sales service customers are charged Rate C1 for their use of the Panhandle System.

f) Please see part c). The allocation of costs to Rate C1 is derived using the sum of the contracted capacities at Ojibway, not the import capacity.

g) The Detroit River crossing transmission assets between the international border and Ojibway are included as part of the Panhandle System and directly assigned to Rate C1. The Detroit River crossing assets are fully depreciated and the annual revenue requirement is immaterial.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Association of Power Producers of Ontario ("APPrO")

Interrogatory

Reference:

Exhibit B Tab 1 Schedule 1 Appendix C Section 3.1

Preamble:

Enbridge states that the demand costs related to Enbridge's contracted capacity on the St. Clair Pipelines LP system is included in the demand costs of Enbridge's St. Clair System (i.e. the St Clair and Bluewater pipelines).

Question:

a) Please explain why the demand costs of a third-party pipeline system are included in Enbridge's St. Clair demand costs.

b) Please provide the maximum import capacity of each of the St. Clair and Bluewater Pipelines and the capacity under contract by Enbridge.

c) Please provide Enbridge's usage history graph for each of the St. Clair Pipelines and the Bluewater Pipeline both by Enbridge and third parties for each of the last 5 years.

Response

a) The demand costs for Enbridge Gas's contracted capacity on the St. Clair Pipelines LP system are included in the St. Clair Demand functional classification because these pipelines provide the capacity required to facilitate Enbridge Gas's Rate C1 transportation service between Dawn and St. Clair and Bluewater. As described in Exhibit I.APPrO.3, part h), the costs of the Detroit river crossing, which are Enbridge Gas owned assets, and not third party costs, are also associated with the Rate C1 transportation service and allocated to Rate C1.

b) The maximum import capacity of the St. Clair river crossing on a firm basis is 0.23 PJ/d with Enbridge Gas currently contracting for 0.214 PJ/d of capacity on this pipeline. When available on a one day operational basis, more gas can be imported, however, Enbridge Gas may not be able to sustain or guarantee this additional capacity.

The maximum import capacity of the Bluewater river crossing is 0.30 PJ/d with Enbridge Gas currently contracting for 0.127 PJ/d of capacity on this pipeline.

The maximum import capacity does not represent Enbridge Gas's annual firm daily capability due to the constraints of the Sarnia market.

c) Please see Figure 1 and Figure 2 for the physical activity associated with the St. Clair and Bluewater river crossings for the last 5 years.

Figure 1

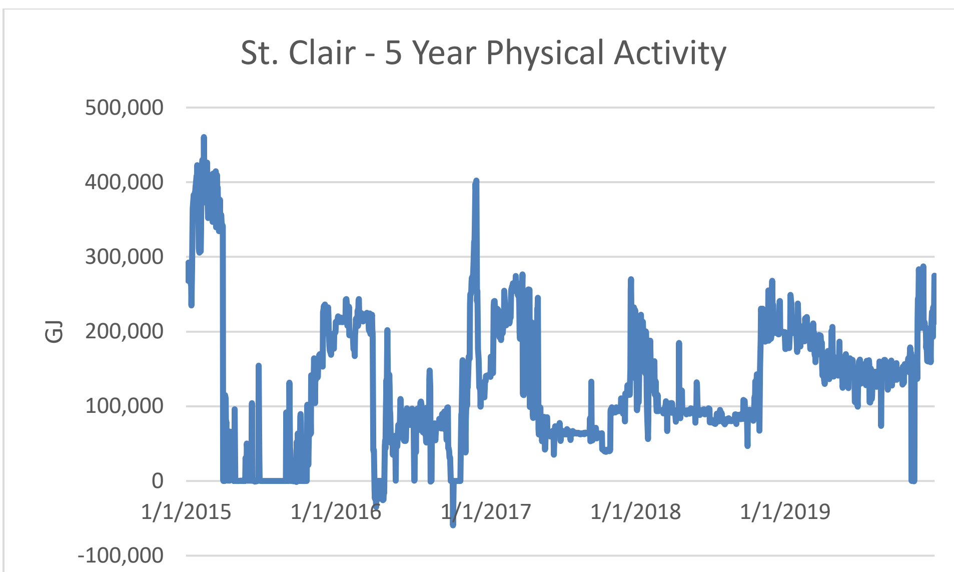
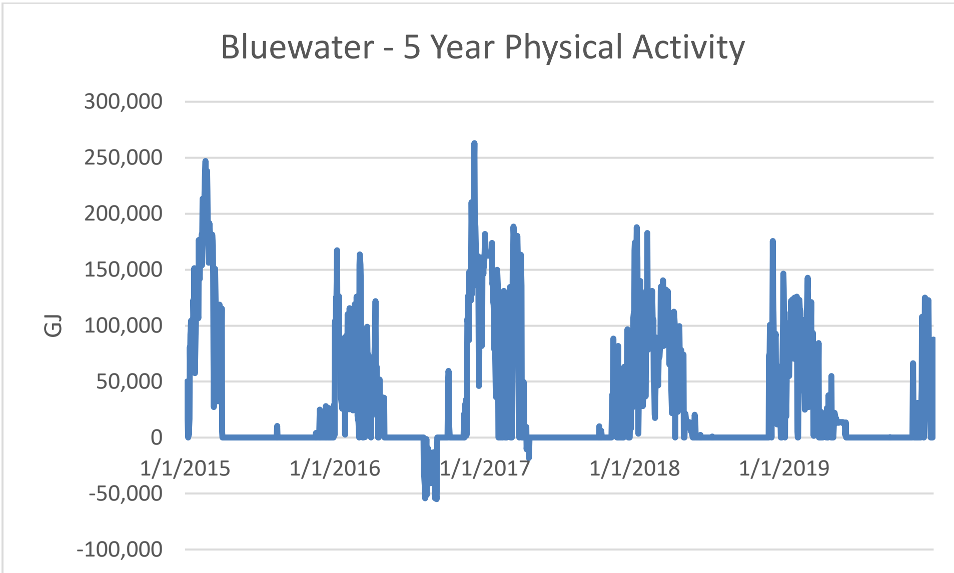


Figure 2


Bluewater - 5 Year Physical Activity
GJ
300,000
250,000
200,000
150,000
100,000
50,000
0
-50,000
-100,000
1/1/2015
1/1/2016
1/1/2017
1/1/2018
1/1/2019

ENBRIDGE GAS INC.

Answer to Interrogatory from
Association of Power Producers of Ontario (“APPrO”)

Interrogatory

Reference:

Exhibit B Tab 1 Schedule 1 Appendix C Section 3.1

Preamble:

Enbridge states that the Parkway measuring and regulating costs are allocated in proportion to the bidirectional design day demands.

Question:

a) Please provide the easterly and westerly design day flows at Parkway and explain how these are determined.

Response

The total westerly design day demands at Parkway are 39.058 $10^6m^3/d$ and includes the Parkway Delivery Obligation for Union South rate zone customers of 5.621 $10^6m^3/d$ and ex-franchise C1 Parkway to Dawn demands of 33.437 $10^6m^3/d$.

The total easterly design day demands at Parkway are 147.708 $10^6m^3/d$ and includes the Union North rate zone Dawn-Parkway transportation requirements of 10.170 $10^6m^3/d$, ex-franchise C1 Dawn to Parkway transportation for Union North rate zone T-service customers of 0.857 $10^6m^3/d$, ex-franchise Rate M12/C1 Dawn to Parkway demands of 125.868 $10^6m^3/d$ and ex-franchise M12 Kirkwall to Parkway demands of 10.813 $10^6m^3/d$.

Ex-franchise shippers directly contract for C1 and M12 transportation services and the contracted values are summed by direction for those with a Parkway receipt or delivery point.

The Union South Parkway Delivery Obligation values are determined by the obligated deliveries at Parkway for Union South direct purchase contract rate customers.

The Union North Dawn to Parkway transportation requirements are determined by the reference to the Company’s gas supply plan.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Association of Power Producers of Ontario ("APPrO")

Interrogatory

Reference:

EB-2017-0306/EB-2017-0307 Decision and Order dated August 30, 2018, amended September 17, 2018 (the "MAADs Decision")

Preamble:

Page 41 of the MAADs Decision states:

"**OEB Findings**

Amalco is expected to prepare and file a comprehensive cost allocation proposal to be filed with its next rebasing application following the five year deferred rebasing period.

However, the OEB is concerned about the cost allocation issues raised by parties for Union Gas' Panhandle and St. Clair systems. The OEB therefore requires Amalco to file a cost allocation study in 2019 for consideration in the proceeding for 2020 rates that proposes an update to the cost allocation to take into account the following projects: Panhandle Reinforcement, Dawn- Parkway expansion including Parkway West, Brantford-Kirkwall/Parkway D and the Hagar Liquefaction Plant. This should also include a proposal for addressing TransCanada's C1 Dawn to Dawn TCPL service. The OEB accepts that this proposal will not be perfect, but is intended to address the cost allocation implications of certain large projects undertaken by Union Gas that have already come into service."

Question:

a) Please explain how the OEB's concerns about the cost allocation issues raised in the MAADs Decision are being addressed if Enbridge defers rate changes to Enbridge's next rebasing in 2024?

Response

a) Please see Exhibit I.STAFF.4 part a).

ENBRIDGE GAS INC.

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

INTERROGATORY

Reference:

Exhibit B, Tab 1, Schedule 1, Appendix C, p5

Question:

a) Please provide a full explanation for the substantial increase in the Board-approved increase in revenue deficiency for M4 customers ($5,491,000, or about 20%), as shown in Table 1, line 5.

b) Why is the increase for M4 customers so much larger in percentage terms than the approved rate increase for Rates 1 and 2 customers?

c) Please explain how the further increase in revenue requirement for M4 customers, due to the company's cost allocation proposals of $3,414,000, is calculated, and why is it so much larger on a percentage basis of the 2019 Board-approved and 2020 proposed revenue requirement than the proposed increases in M1 and M2 customers' revenue requirement.

Response

a) The revenue deficiency of Rate M4 is primarily driven by two factors.

First, distribution-related rate base has increased since Union's 2013 Cost of Service proceeding (EB-2011-0210) which is the base year for current rates. Throughout Union's 2014-2018 IRM, transmission-related rate base has increased in rates for the approved capital pass-through projects and allocated to rate classes using the 2013 cost allocation study. The 2019 cost allocation study includes the rate base for distribution additions since 2013 which results in a revenue deficiency compared to current approved revenue.

Second, as part of Union's 2013 Cost of Service proceeding (EB-2011-0210), Rate M4 costs were reduced by $3.4 million of S&T margin resulting in a revenue to cost ratio for the rate class of 0.783[1]. The $3.4 million of S&T margin includes an adjustment of $2.9 million for rate design considerations for the rate class. The revenue deficiency provided at Exhibit B, Tab 1, Appendix A, Table 1 does not include adjustments for rate design considerations.

b) Please see part a). The 2013 revenue to cost ratio for Rate M1 and Rate M2 was 0.998 and 0.972, respectively, as compared to the revenue to cost ratio for Rate M4 of 0.783. The cost allocation study directive has not been adjusted for rate design considerations, which has resulted in a larger revenue deficiency for Rate M4 relative to Rate M1 or Rate M2.

c) The increase of $3.414 million in the revenue requirement for Rate M4 customers related to Enbridge Gas's cost allocation proposals is driven by the proposed cost allocation methodology of the Panhandle and St. Clair Systems, as shown at Exhibit B, Tab 1, Schedule 1, Appendix C, page 9, Table 2, line 8, column (a).

The Panhandle/St. Clair cost allocation proposal results in a $3.829 million increase to the revenue requirement of Rate M4, which is partially offset by a reduction of $0.403 million related to the Parkway Station cost allocation proposal and a reduction of $0.012 million related to the Dawn Station cost allocation proposal.

The proposed cost allocation methodology results in an allocation to Rate M4 that is higher than the allocation to Rate M1 and Rate M2 primarily as a result of two factors:

- The cost allocation increase of the Panhandle and St. Clair System proposal is offset in a greater proportion to Rate M1 and Rate M2 by the proposed cost allocation decreases of the Parkway Station and Dawn Station proposals than to Rate M4. Rate M4 design day demands on the Panhandle System are a greater proportion of the total Panhandle System design day demands than Rate M4 is of the distance-weighted design day demands of the Dawn-Parkway system.

- The cost allocation of the Panhandle and St. Clair System results in a larger proportion of costs to Rate M4 as a result of the removal of the St. Clair design day demands from the allocator of Panhandle Demand costs.

[1] Exhibit I.LPMA.3, Attachment 1.

ENBRIDGE GAS INC.

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

INTERROGATORY

Reference:

Ibid

Question:

Please provide the approximate rate impact for a typical M4 customer, resulting from the rate changes proposed in 2020 with and without the cost allocation proposals.

Response

Enbridge Gas is not proposing any rate changes in this application.

Please see Exhibit I.STAFF.4 part c) for the estimated in-franchise bill impacts associated with the cost allocation study results, including Rate M4. Exhibit I.STAFF.4, Attachment 1 provides bill impacts including the cost allocation proposals and Attachment 2 provides bill impacts excluding the cost allocation proposals.

ENBRIDGE GAS INC.

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

INTERROGATORY

Reference:

Ibid

Question:

Please explain the reasons for the large decrease in revenue requirement in 2020 over 2019 for the M12/Cl revenue requirement ($24,593,000) and the offsetting adjustment of $7,676,000, due to the cost allocation proposals.

Response

The Rate M12/C1 revenue sufficiency result[1] of the cost allocation study is primarily driven by two factors.

First, the cost of capital parameters have been updated in the 2019 cost allocation study to reflect the 2019 forecast cost of capital. The Board-approved cost allocation study from Union's 2013 Cost of Service proceeding (EB-2011-0210) reflected a weighted average return on rate base of 7.32% compared to 5.93%[2] in the 2019 cost allocation study directive. The decrease in the weighted average return on rate base contributes to the revenue sufficiency of Rate M12 because current approved revenue reflects the 2013 return on rate base, updated for the incremental return on rate base from the approved capital pass-through projects. The rate base underpinning Rate M12 current approved revenue has been largely updated during Union's 2014-2018 IRM through the approved capital pass-through projects.

Second, the 2019 cost allocation study directive reflects an increase to distribution-related rate base and operating costs since Union's last rebasing in 2013. The allocation of costs to Rate M12 is predominantly transmission-related. The majority of transmission-related rate base and operating costs since 2013 have been updated in

[1] Rate M12 revenue sufficiency of $24.593 million using Board-approved cost allocation methodologies.
[2] Calculated as total return on rate base of $371.140 million divided by total rate base of $6,256.966 million per Exhibit B, Tab 1, Appendix C, Working Papers, Schedule 1, p.2, line 5.

rates during Union's 2014-2018 IRM through the approved capital pass-through projects revenue requirement. Consistent with the response to Exhibit I.BOMA.1, the 2019 cost allocation study includes distribution-related rate base and operating costs additions since 2013 which has resulted in a shift of indirect costs away from transmission-related functions and into the distribution-related functions within the cost study. This shift of costs into distribution-related functions results in a reduction to transmission-related costs relative to current approved rates.

The proposed Parkway Station cost allocation methodology largely contributes to the decrease in the Rate M12/C1 – Dawn/Parkway revenue sufficiency by $7.676 million from $24.593 million to $16.916 million. The Parkway Station cost allocation proposal increases the allocated revenue requirement to Rate M12/C1 by $7.669 million as shown at Exhibit B, Tab 1, Schedule 1, Appendix C, page 9, Table 2, line 17, column (b).

The increase in the revenue requirement to Rate M12/C1 of the Parkway Station cost allocation methodology proposal is due to the larger proportion of Rate M12/C1 demands at Parkway Station compared to the proportion of Rate M12/C1 distance weighted demands on the Dawn-Parkway system. As described in evidence, Enbridge Gas has proposed to separate the Parkway Station costs from the Dawn-Parkway Easterly Demand functional classification in the cost allocation study.

The Board-approved cost allocation methodology includes Parkway Station costs in the Dawn-Parkway Easterly Demand functional classification which is allocated based on distance-weighted design day demands and results in an allocation of 76.5% of costs to Rate M12/C1.

The proposed cost allocation methodology for Parkway Station costs allocates measuring and regulating costs in proportion to the bi-directional design day demands of the Parkway Station; compressor costs in proportion to the easterly design day demands requiring compression at Parkway; and all remaining Parkway Station costs in proportion to the Parkway Station measuring and regulating and compressor net plant. The allocation to Rate M12/C1 is 90.5%, 91.1%, and 90.6% of Parkway Station measuring and regulating, compressor, and all other costs, respectively.

The proposed cost allocation methodology increases the Parkway Station costs allocated to Rate M12/C1 from 76.5% to approximately 91% resulting in the increase in allocated costs of $7.669 million.

ENBRIDGE GAS INC.

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

INTERROGATORY

Reference:

Exhibit B, Tab 2, Schedule 1, p4 of 31

Question:

a) Please discuss the extent to which capital expenditures for system access, system service, general plant, and overheads, for the Union and EGD rate zones, are different from one another.

b) Are the same as one another.

c) The extent to which each type of investment project may be labeled differently in two rate zones. Please lease provide examples for any differences.

Response

a) The categories of system access, system service, system renewal and general plant are outlined in Chapter 5 of the Filing Requirements for Electricity Applications. Legacy EGD and legacy Union each mapped their unique investment categories based on the descriptions of the categories.

The Union and EGD rate zones have similar types of projects, however capital spend between the rate zones will vary based on differences associated with the locations being served. For example, the number of customer attachments and the prioritization of risks are specific to each rate zone. More specifically:

- EGD rate zone has significantly higher spend in the category of system access. This is a result of higher customer additions in the EGD rate zone, which experience higher urban growth compared to the Union rate zones which are more rural.

- The Union rate zone has higher capital spend in the category of system service. Union rate zones have a larger need for transmission projects compared to EGD rate zone due to the footprint of the legacy system and growth with the Dawn-Parkway system.

- The capital spend for both EGD and Union rate zones varies in the category of system renewal based primarily on the timing of in-service dates for future projects.

- The overheads capitalized differ between Union and EGD rate zones as each legacy utilities operated under different overhead capitalization processes. Harmonization of overheads will be achieved through the utility integration activities.

b) The nature of capital spend is similar between the Union and EGD rate zones, however the amount of spend will not be similar due to the differences noted in part a).

c) Program names vary by legacy utility, however the nature of the capital spend is the same. For example, EGD rate zone uses the term ‘rebillable relocations’ which is equivalent to the Union rate zones term of ‘municipal replacement’. One notable difference in the categorization is the treatment of Integrity program costs. EGD rate zone separates Integrity work between system renewal and system service whereas Union categorizes Integrity entirely under system renewal. Also, the EGD rate zone separates the Meter Exchange Program between system access and system renewal to distinguish the growth related meters whereas Union rate zones presents all meter purchases under system renewal. This is a function of how programs have been historically tracked within the utilities and will be aligned beginning in 2020 as a result of using a common Asset Management tool.

ENBRIDGE GAS INC.

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

INTERROGATORY

Reference:

Exhibit B, Tab 2, Schedule 1, Appendix C, p18

Question:

Please provide a copy of the Request to Vary for the project.

Response

Please see Exhibit I.VECC.1.

ENBRIDGE GAS INC.

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

INTERROGATORY

Reference:

Ibid, p23

Question:

The evidence states that the current forecast cost of the project of $35.4 million has increased from the $25.6 million included in the EB-2018-0108 filing, an increase of $10.2 million, or 40%, which appears excessive.

a) Please confirm that the cost categories included in the two budgets, namely material, construction and labour, land costs, contingencies, overheads, and interest during construction, are the same for both forecasts.

b) Are any new cost categories included in the current 2019 estimate?

c) Please provide details of the proposed cost increases for each cost category noted above.

Response

a) The table below was filed at Exhibit I.EP.16, page 2 in EB-2018-0305. This table confirms that the cost categories are the same for both forecasts:

Item No.	Description	Cost As Filed in EB-2018-0108	Updated Cost Estimate	Variance
		a	b	b-a
1.0	Material Costs	$710,107	$710,107	$0
2.0	Labour Costs	$17,060,285	$17,060,285	$0
3.0	External & Regulatory Costs	$860,000	$1,433,528	$573,528
4.0	Land Costs	$301,000	$2,264,746	$1,963,746
5.0	Overhead Costs	$759,000	$9,989,358	$9,230,358
6.0	Interest During Construction	$208,255	$209,093	$838
7.0	Contingency Costs	$5,698,892	$3,687,764	($2,011,128)
8.0	Total Project Cost	$25,597,539	$35,354,881	$9,757,342

b) No new cost categories are included. However, it is important to note that the cost estimate in the LTC Application (EB-2018-0108) includes only direct overhead costs, and not indirect overheads (fully burdened costs). The inclusion of indirect overheads in the ICM request is the main driver of the noted cost difference. The OEB confirmed that indirect overhead costs (capitalized overheads) are appropriately included in the ICM funding calculation in the September 12, 2019 Decision and Order in EB-2019-0305.

c) As indicated in Exhibit I.EP.16, page 2 in EB-2018-0305, variances in estimated costs relative to what was filed in the LTC application can be attributed to an increase in the cost related to the required permanent and temporary working easements for the project and the inclusion of indirect overhead costs.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Building Owners and Managers Association, Greater Toronto (“BOMA”)

INTERROGATORY

Reference:

Windsor Line Leave to Construct Application (EB-2019-0172)

Question:

Please provide a copy of EGI's Argument-in-Chief in EB-2019-0172, EGI's leave to construct application for the Windsor Line.

Response

Please see Attachment 1.

Rakesh Torul
Technical Manager
Regulatory Applications
Regulatory Affairs

tel 416-495-5499
EGIRegulatoryProceedings@enbridge.com

Enbridge Gas Inc.
500 Consumers Road
North York, Ontario M2J 1P8
Canada

VIA EMAIL, RESS and COURIER

January 27, 2020

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

Re: EB-2019-0172 Enbridge Gas Inc. ("Enbridge Gas")
Windsor Line Replacement Project – Argument-in-Chief

Dear Ms. Long:

In accordance with Procedural Order No.5 dated January 15, 2020, enclosed is Enbridge Gas' Argument-in-Chief in the above noted proceeding.

Please contact the undersigned if you have any questions.

Yours truly,

(Original Signed)

Rakesh Torul
Technical Manager,
Regulatory Applications

cc: Guri Pannu, Sr. Legal Counsel
EB-2019-0172 Intervenors

ONTARIO ENERGY BOARD

IN THE MATTER OF The Ontario Energy Board Act, 1998, S.O. 1998, c.15, Schedule B, and in particular, S.90.(1) and S.97 thereof;

AND IN THE MATTER OF an Application by Enbridge Gas Inc. for an Order granting leave to construct natural gas pipelines and ancillary facilities in the Municipality of Chatham-Kent and County of Essex.

ARGUMENT-IN-CHIEF OF ENBRIDGE GAS INC.

1. In this project Enbridge Gas Inc. ("Enbridge Gas") has applied for a leave to construct a natural gas pipeline in the Municipality of Chatham Kent and the County of Essex.

2. Enbridge Gas has requested the following orders from the Ontario Energy Board ("OEB").

   (a) Pursuant to Section 90 (1) of the Ontario Energy Board Act ("the Act"), granting leave to construct approximately 64 kilometres of NPS 6 pipeline and ancillary facilities and,

   (b) Pursuant to Section 97 of the Act, granting approval of the form of easement agreements as referenced in evidence at Exhibit B, Tab 1, Section 7.

Overview

3. A significant portion of the existing pipeline consists of pipe that is between 70 to 90 years old. Along with the age of the pipeline there has been an increasing amount of pipeline integrity issues. Accordingly, Enbridge Gas is proposing to construct approximately 64 kilometres of NPS 6 hydrocarbon (natural gas) pipeline ("Proposed Pipeline", "Windsor Line" or the "Project") in order to replace a section of the existing Windsor NPS 10 pipeline (along with short sections of

NPS 8 pipe). The Proposed Pipeline will extend between an interconnect at the existing Enbridge Gas Port Alma Transmission Station (located in the Municipality of Chatham-Kent) and the intersection of Concession 8 and County Road 46 (located in the Town of Tecumseh). Construction will take place within the Towns of Tecumseh and Lakeshore as well as the Municipality of Chatham-Kent and the County of Essex.

4. The Windsor Line receives natural gas from the existing Enbridge Gas Panhandle Transmission Pipeline Line and in turn serves as a trunkline to bring service to a number of downstream distribution systems as well as residents and businesses located along its path from Port Alma to the City of Windsor. As stated in pre-filed evidence at Exhibit B, Tab 1, Schedule 1, pg. 1, a total of 399 customers are currently being served off the section of Windsor Line being replaced.

Design and Construction of the Proposed Pipeline and Ancillary Facilities

5. Enbridge Gas has designed the Project to meet or exceed all applicable codes and regulations. Enbridge Gas is proposing to construct the Project in 2020 following its standard construction practices which have been continuously reviewed and updated to ensure the Project will be constructed safely and that impact to the lands and environment are minimized. As noted at Exhibit B, Tab 1, Schedule 5, material is readily available to construct the Project.

6. As described at Exhibit B, Tab 1, Schedule 5, the Project will be designed and constructed in accordance with the Ontario Regulations 210/10 under *the Technical Standards and Safety Act 2000, Oil and Gas Pipeline Systems*. This is the regulation governing the installation of pipelines in Ontario. The Proposed Pipeline will also meet or exceed the design and construction requirements of the applicable current edition of CSA Z662. Areas where abandonment of the existing pipe is to occur, Enbridge Gas will also comply with all applicable guideline and code requirements.

7. Enbridge Gas is proposing to commence construction of the Project in the spring of 2020 and be complete by year-end. Additional work such as clean up, abandonment and the installation of new services will continue into 2021.

Environmental Matters

8. The OEB's Environmental Guidelines for the Location, Construction and Operation of Hydrocarbon Pipelines in Ontario is addressed at Exhibit B, Tab 1, Schedule 6 of Enbridge Gas's pre-filed evidence and a copy of Enbridge Gas's Environmental Report ("ER") for the Project is filed in Exhibit C, Tab 6, Schedule 1. In Enbridge Gas's submission, subject to the implementation of the recommendations in the ER any potential adverse residual environmental and socio-economic effects of the Project are not anticipated to be significant.

9. Following the completion of the ER by Stantec Consulting Ltd., a copy was provided to the Ontario Pipeline Coordination Committee ("OPCC") on July 22, 2019. A copy of the ER was also forwarded to the local Conservation Authority, municipalities including the Town of Tecumseh, the Town of Lakeshore, County of Essex, Municipality of Chatham-Kent and local First Nations for review and comment.

10. The ER identifies various mitigation measures to minimize the impacts of the Project on the environment. Enbridge Gas will use its standard environmental inspection program to ensure that the recommendations in the ER are followed and that all activities comply with whatever Conditions of Approval are mandated by the OEB.

Landowner Matters

11. With the Proposed Pipeline being constructed entirely within road allowance, the land rights necessary for the construction of the Project involve the acquisition of temporary easement land rights from individual landowners. Fee simple purchases are also required at the site where existing stations along the proposed route are being upgraded.

12. Enbridge Gas will offer to all landowners where temporary land use is required a form of Temporary Land Use (“TLU”) agreement. Enbridge Gas has had several discussions with private landowners. As a result of these discussions and as noted at Exhibit I.STAFF.10 b), Enbridge Gas amended its land right requirements. Enbridge Gas maintains that all necessary land rights will be in place prior to the commencement of construction.

13. To construct the Project, Enbridge Gas also requires permits or agreements with various agencies and municipalities along the route. These permits and agreements will be in place prior to construction.

14. As stated in response to OEB staff interrogatories, Enbridge Gas is installing a portion of the pipeline (i.e. 29 kilometres) in the County of Essex (the “County”). Enbridge Gas is currently in negotiations with the County regarding the location of the Proposed Pipeline in road allowance. Enbridge Gas and the County have agreed to 23 of 29 kilometres. To date, Enbridge Gas and the County have not agreed to the location of 6 kilometres of the pipeline within road allowance. For the remaining 6 kilometres, Enbridge Gas is working with the County on a pipeline alignment that takes into account a potential road widening the County is planning to undertake in the future.

Indigenous and Métis Nations Consultation

15. As detailed at Exhibit B, Tab 1, Schedule 8 and further updated in Enbridge Gas’s responses to Exhibit I.STAFF.11, Enbridge Gas has followed the OEB/Ministry of Energy Northern Development and Mines (“MENDM”) processes in relation to Indigenous consultation. On January 20, 2020 Enbridge Gas received a letter from the MENDM advising that Enbridge Gas’s consultation activities were sufficient.

Project Need: Pipeline Integrity Concerns

16. As set out in Enbridge Gas's pre-filed evidence, the Windsor Line has been deemed an operational risk. This was further addressed at Exhibit I.STAFF.2 where Enbridge Gas states the Windsor Line first became a potential operational risk back in 2015. As described at Exhibit C, Tab 3, Schedule 1, Enbridge Gas reviewed a series of alternatives before determining the Project to be the preferred option.

17. Below is a summary of the integrity issues that have been highlighted throughout the evidence including Enbridge Gas's application, additional interrogatories that Enbridge Gas provided in advance of the Technical Conference and its answers to undertakings from the Technical Conference. Enbridge Gas believes if these issues are not addressed, they impact both the safety and security of the pipeline. The following is a summary of the main integrity issues impacting the line:

i) Leaks

There is a history of leakages on the Windsor Line with significant costs to repair the pipeline in the near future. As indicated in Exhibit I.STAFF.2, the latest leak survey in 2019 confirmed that there are currently 24 active leaks and 3 inoperable mainline valves. Additionally, if the pipeline were to be isolated, there would be significant customer outages.

ii) Weldability

All joints prior to the 2000s were made with unrestrained mechanical couplings and portions of the older vintage pipe are not weldable.

iii) Depth of Cover/Damage

The Windsor Line also has sections that have poor depth of cover with less than 0.6 metres that could also pose safety and security of supply risks if not addressed. There are several exposed ditch crossings and areas in agricultural fields with depth of cover issues[1]. In JT1.18, there would be an incremental cost of $10 million to $18 million in 2020 through 2022 to address the depth of cover issues.

iv) Costs Spent on Maintenance

As indicated in Exhibit JT1.18, the cost for repair and maintenance is expected to increase each year. The estimated maintenance costs for the leak repairs are shown in the table below.

	2017	**2018**	**2019**	**2020**	**2021**	**2022**
Total	$203,085	$169,185	$250,485	$381,000	$685,000	$857,000

The estimated costs shown in the table include, but are not limited to, such things as leak surveys, leak monitoring, leak repairs, rectifier replacements and station maintenance.

v) Service Interruptions

(a) As indicated in part i) above, there are 3 inoperable mainline valves on the Windsor Line. If the pipeline had to be isolated, this will result in significant customer outages.

[1] Enbridge Gas Interrogatory Exhibit I.STAFF.2

18. Delaying the Project's in-service date of November 2020 will result in these integrity concerns becoming increasingly serious and additional funds will be required to mitigate concerns.

The Facilities:

19. The NPS 6 Proposed Pipeline is replacing a larger diameter NPS 10 (and smaller sections of NPS 8 pipe). As stated at Exhibit B, Tab 1, Schedule 2, the Proposed Pipeline will feature a decrease in pipe diameter and an increase in Maximum Operating Pressure ("MOP") as compared to the NPS 10 pipe being replaced. The existing Windsor Line, the majority of which is NPS 10, operates at a pressure of 1380 kPa where the Proposed Pipeline would operate at 3450 kPa. Despite the reduction in diameter, as a result of the increased MOP there will be no significant change in the capacity available from the Proposed Pipeline at this time.

20. The proposed design incorporates the NPS 6 replacement as well as smaller networks of plastic distribution piping. With the new design, 270 service connections will connect to the new NPS 6 pipeline and 129 services will connect to the new distribution network. The Project also involves upgrading 14 existing stations in order to handle the increase in MOP. Five new stations are planned to be installed and four existing stations are targeted for abandonment.

21. The majority of the existing Windsor Line will be removed. However, in areas where it is not practical to remove the existing pipeline (i.e. road and water crossings) the pipe will be abandoned in place.

22. The estimated total cost of the Project is $106.8 million (including indirect overheads of $14.1 million). The total cost includes the cost of the mainline NPS 6 pipeline as well as the costs of the ancillary facilities (i.e. services, stations and plastic distribution mains). As detailed at Exhibit I.STAFF.6 b), since the Project was underpinned by integrity requirements (and not growth) a discounted cash flow ("DCF") report was not completed. As noted at Exhibit B, Tab 1, Schedule 4,

Enbridge Gas expects the Project will meet the criteria for rate recovery during the deferred rebasing period through the use of the OEB's Incremental Capital Module ("ICM") mechanism. The ICM request for the Project was included as part of Enbridge Gas's 2020 Rates application (EB-2019-0194)[2].

23. The balance of these submissions is organized based on the issues that were raised by the intervenors, Energy Probe ("EP") and the Federation of Rental-Housing Providers ("FRPO"), OEB staff in its interrogatories and the Technical Conference. Apart from integrity concerns, the issues for which the parties above sought further clarity are listed below:

(a) Sizing of the Proposed Pipeline (NPS 6) and Project Alternatives

(i) Load growth (forecast and unforecast)

(b) Costing of the Proposed Pipeline compared to Project Alternatives

<u>Sizing of the Proposed Pipeline (NPS 6) and Project Alternatives</u>

24. Although Enbridge Gas has seen increased natural gas demand within the Region of Windsor Facilities Business Plan ("FBP") Study, due to the location of this forecasted growth it was not a major consideration when designing the Proposed Pipeline. Rather, the Proposed Pipeline was designed as a "like-for-like" replacement with the existing NPS 10 Windsor Line in terms of capacity.

25. Enbridge Gas in its pre-filed evidence and interrogatory responses proposed the installation of an NPS 6 pipeline because the size of the pipeline is capable of meeting the forecasted demand as well as unforecasted demand that may be requested in the area. FRPO questioned the use of an NPS 6 pipeline design based on current demands on the system. FRPO proposed the use of an NPS 4

[2] See EB-2019-0194 evidence update submission dated January 15, 2020

alternative as well as a "hybrid" option that involved the installation of a portion of NPS 4 and NPS 6 pipe. In its response to Exhibit I.FRPO.12, Enbridge Gas dismissed the use of an NPS 4 exclusively by stating, that the *"NPS 4 pipeline will not serve the existing demand requirements on design day."* As for the proposed hybrid option (NPS 4 and NPS 6) Enbridge Gas responded that since 40% of the proposed line requires the capacity of NPS 6 if the hybrid option were used, Enbridge Gas would be unable to meet unforecasted demand of commercial and industrial customers outside the Windsor FBP (see Exhibit I.FRPO.15).

26. In addition to the limitations of meeting unforecasted demand, Enbridge Gas also expressed the operational restrictions that the NPS 4 provides:

> Downsizing any portion of the Project to NPS 4 will limit future growth potential, including any unanticipated future growth as a portion of NPS 4 will be a bottleneck on the system. It is also inefficient and imprudent to downsize any portion of a pipe that is capable of flow in both directions for emergency and/or maintenance related events[3].

With an NPS 6 pipeline there is a lower chance of customer outages/impacts in operational or emergency situations due to cold weather. This operational flexibility was further addressed in response to a series of pre-Technical Conference questions submitted by FRPO (Exhibit KT1.3 and KT1.6). It was also addressed in response to Undertaking JT1.3 where Enbridge Gas once again confirmed that any inclusion of NPS 4 and NPS 2 piping will restrict capacity for future unforecasted growth, as well as operational and emergency flexibility.

27. The unforecasted demand is generally received in the rural Windsor areas from large agricultural and greenhouse customers. As stated at Exhibit KT1.5 part b) ii), the locations and demands of these customers are difficult to predict. For this reason, they are generally not included in the scope of an FBP. Enbridge Gas

[3] Enbridge Gas letter dated November 14, 2019

also acknowledged it has received inquiries surrounding the Port Alma area in the past two years[4]. In its response to Undertakings, Enbridge Gas advised it had received inquiries of approximately 8,000 m3/hour east of Comber. These total loads demonstrate the importance of the NPS 6 design in order to meet unforecasted demands in the area of the pipeline. Also, Enbridge Gas received letters of support from municipalities and other agencies[5] in the area, such as the Town of Essex, Windsor-Essex Economic Development, Town of Tecumseh, Windsor-Essex Regional Chamber of Commerce and the Municipality of Chatham-Kent. They all unanimously agreed that the Windsor Line Replacement Project will support future growth in the Windsor-Essex region.

28. As indicated in response to Undertaking JT1.15, "the Windsor Line would be able to feed similar customer requests in the future as they are in the area supplied by the Windsor Line through Port Alma." At Exhibit KT1.6 Enbridge Gas also raised the fact that when assessing the NPS 4 and NPS 4 and NPS 6 hybrid options, future growth on the Windsor Line system will require reinforcement sooner than if all NPS 6 was installed. This further supports the overall prudency of Enbridge Gas's proposal to replace the existing NPS 10 pipeline entirely with NPS 6.

<u>Costing of the Proposed Pipeline compared to Project Alternatives</u>

29. FRPO also raised concerns with the cost difference between the NPS 4, the hybrid of NPS 4/6, and the Proposed Pipeline. FRPO has suggested that the hybrid of NPS4/6 would reduce the cost of the Project by "millions of dollars"[6]. FRPO attempted to support this claim by requesting Enbridge Gas to provide costing details of historical examples of pipeline projects. As part of its November 28, 2019 pre-Technical Conference submission, FRPO requested Enbridge Gas to provide costing data for specific projects over the last 10 years that range in size from NPS 2 to NPS 6. Enbridge Gas responded to the request on a best

[4] Enbridge Gas Undertaking Response Exhibit JT1.15
[5] Enbridge Gas Application, Exhibit C, Tab 1, Schedule 2, pp 1-6
[6] FRPO letter dated November 9, 2019

effort basis (see Exhibit KT1.4). The response included actual cost schedules and post construction financial reports that were filed with the OEB for three pipeline projects that best met the criteria identified in the question.
FRPO requested a unit cost to construct per kilometre for these projects. In addition, at Exhibit JT1.9 Enbridge Gas was able to provide an average unit cost to install NPS 2, NPS 4 and NPS 6 in the Windsor Region over the past five years. FRPO is relying on the unit costs and cost differences to support the submission that the Windsor Line at NPS 6 and the hybrid NPS 4/6 option cannot be a difference of $800,000. The primary difference between the NPS 6 and the hybrid NPS 4/6 stems from materials.

30. Enbridge Gas cautioned that using the projects above were not appropriate comparison data points because these average unit costs resulted from small pipeline projects such as new general infill expansion enhancement to existing pipelines (i.e. small reinforcements). As mentioned above the Windsor Line replacement is a much larger project as the pipeline requires a construction of 64 kilometres of pipeline.

31. Enbridge Gas submits as stated throughout the evidence that the NPS 6 option provides greater flexibility (maintenance and emergency response), and the ability to meet unforecasted demand and therefore preventing the need for a future reinforcement. Considering the difference in cost of $800,000 between the NPS 6 and the hybrid NPS 4/6, the NPS 6 provides the best option when considering the factors above.

<u>Conclusion</u>

32. The Project is needed to address the existing integrity concerns on Windsor Line. Similarly, as addressed earlier in this submission, if the Project is not constructed as proposed, the ongoing effort and resources required to address these integrity concerns will only increase in the future. The proposal to replace the existing NPS 10 Windsor Line with NPS 6 is prudent from both an operational and

engineering perspective as well as ratepayer perspective. The Project is the most effective and prudent way of managing the ongoing safety and reliability of the Windsor Line.

33. The proposed in-service date for the Project is November 1, 2020. In Exhibit I.STAFF.12, OEB staff proposed certain Conditions of Approval, one of which was the requirement at 2(b), part i) for Enbridge Gas to give the OEB notice in writing of the commencement of construction, at least ten days prior to the date construction commences. Enbridge Gas respectfully requests the 10-day requirement be removed and that Enbridge Gas be required to provide notice, at the latest, at the beginning of construction. Enbridge Gas would like to begin construction immediately in order to ensure the in-service date of the project is preserved and submits that no party will be adversely affected by this timing. In order to facilitate efficient project development and meet its proposed in-service date, Enbridge Gas respectfully requests the OEB issue its approval in a timely manner.

All of which is respectfully submitted, this 27th day of January 2020

ENBRIDGE GAS INC.

[original signed by]

Guri Pannu, Senior Legal Counsel

ENBRIDGE GAS INC.

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

INTERROGATORY

Reference:

Exhibit B, Tab 2, Schedule 1, Appendix C, p27

Question:

a) Please provide any documents related to customer consultations for the Windsor Line, including the formal consultation process, any letters or other communications, either in support of or opposed to the proposed Windsor Line investment.

b) Please provide any studies done by EGI on the pipeline integrity issues, including studies pursuant to the pipeline integrity management program, which prompted the decision to propose the Windsor Line.

Response

a) Please see Exhibit I.EP.12.

b) The question of need for the Windsor Line Replacement project is being addressed in the LTC application (EB-2019-0172). As described in evidence in that proceeding, the Windsor line was risk assessed based on the known integrity issues associated with the pipeline supported by past surveys and inspections such as leakage and depth of cover to underpin the justification to senior management. For additional detail regarding the integrity concerns specific to the Windsor line please refer to EB-2019-0172 Exhibit B Tab 1 Schedule 1, pages 1-2; EB-2019-0172 Exhibit I.Staff.2, page 2; and EB-2019-0172 Exhibit JT1.19, page 1. No additional studies pursuant to the Pipeline Integrity Management Program were completed in association with the justification of this pipeline replacement.

ENBRIDGE GAS INC.

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

INTERROGATORY

Reference:

Windsor Line Leave to Construct Application (EB-2019-0172)

Question:

The Leave to Construct application is ongoing and EGI's Argument-in-Chief was filed on January 27, 2020 (a few days ago). The intervenors' arguments are due February 10, 2020, and the Reply Argument is due February 24, 2020. Given the fact that the need for the project has not yet been determined by the Board, and that the Board will not likely make a decision until later this spring, and that EGI has stated in its Argument-in-Chief (p12) in the Leave to Construct application that it objects to providing the Board with ten days' notice of commencement of construction, due to the need to commence construction the day after the Board approves its application, if the Board does approve the application, please discuss why the Board should approve ICM status for the project in 2020 at this time, given the likelihood that the project will not be completed and in-service by December 31, 2020. Please discuss fully.

Response

Enbridge Gas does not agree with the premise of the question that suggests the Windsor Line Replacement Project will not be completed and in-service by December 31, 2020. As stated in its EB-2019-0172 Argument-in-Chief (dated January 27, 2020), Enbridge Gas requested the removal of the condition of approval that requires 10 days' notice of commencement of construction. Rather, Enbridge Gas proposed it be allowed to provide notice to the Board, at the latest, at the beginning of construction. Not only will this ensure Enbridge Gas meets the Project in-service date of November 1, 2020, but as stated in its Argument-in-Chief, no party would be adversely affected by this timing.

ENBRIDGE GAS INC.

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

INTERROGATORY

Reference:

Exhibit B, Tab 2, Schedule 1, Appendix C, p28

Question:

Please provide the cost of capital parameters provided by the Board for Union's 2013 cost of service application.

Response

Union's 2013 Board approved cost of capital parameters are provided at Note (1), to Exhibit B, Tab 2, Schedule 1, Appendix E, page 2 of this proceeding. Within Union's 2013 Rates Application, EB-2011-0210, the Board approved cost of capital parameters were provided at Schedule 3 of the Draft Rate Order Working Papers, which were filed on December 13, 2012, and is provided as Attachment 1 to this response.

UNION GAS LIMITED
Summary of Cost of Capital
Calendar Year Ending December 31, 2013

Line No.	Particulars	Utility Capital Structure ($000s)	(%)	Cost Rate %	Requested Return ($000s)
		(a)	(b)	(c)	(d)
	As Filed				
1	Long-term debt	2,257,972	60.35	6.50%	146,868
2	Unfunded short-term debt	(115,296)	(3.08)	1.31%	(1,510)
3	Total debt	2,142,676	57.27		145,358
4	Preference shares	102,248	2.73	3.05%	3,117
5	Common equity	1,496,617	40.00	9.58%	143,376
6	Total rate base	3,741,542	100.00		291,851
	Per Settlement Agreement				
7	Long-term debt	2,234,597	60.17	6.53%	145,957
8	Unfunded short-term debt	(108,513)	(2.92)	1.31%	(1,422)
9	Total debt	2,126,084	57.25		144,535
10	Preference shares	102,248	2.75	3.05%	3,117
11	Common equity	1,485,555	40.00	9.58%	142,316
12	Total rate base	3,713,887	100.00		289,969
13	Change	(27,655)			(1,883)
	Per Board Decision				
14	Long-term debt	2,289,139	61.66	6.53%	149,481
15	Unfunded short-term debt	(15,221) (1)	(0.41)	1.31%	(199)
16	Total debt	2,273,918	61.25		149,281
17	Preference shares	102,248	2.75	3.05%	3,117
18	Common equity	1,336,593	36.00	8.93% (2)	119,358
19	Total rate base	3,712,759	100.00		271,756
20	Change	(1,128) (1)			(18,212)
	Board Approved				
21	Long-term debt	2,289,139	61.30	6.53%	149,481
22	Unfunded short-term debt	(1,287) (3)	(0.03)	1.31%	(17)
23	Total debt	2,287,852	61.26		149,464
24	Preference shares	102,248	2.74	3.05%	3,117
25	Common equity	1,344,432 (3)	36.00	8.93% (2)	120,058
26	Total rate base	3,734,532	100.00		272,639
27	Change	21,773 (3)			883

Notes

(1) Reduction to rate base reflects non-utility allocation changes and the depreciation during the time the St. Clair Line was removed from rate base. This adjustment reduces the unfunded short-term debt found in J5.4 line 8 as follows:

Utility / non-utility cost allocation	(104)	
St Clair Line rate base reduction	(1,024)	
	(1,128)	
debt component at 64%		(722)
Unfunded short-term debt per J5.4 line 8 column (a)		(14,499)
Adjusted total		(15,221)

(2) ROE is calculated per EB-2009-0084 based on September 2012 data.

(3) Updated for January 2013 QRAM, 36% equity and 64% unfunded short-term debt.

ENBRIDGE GAS INC.

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

INTERROGATORY

Reference:

Exhibit B, Tab 2, Schedule 1, pp4 and 5

Question:

Please provide the costs of the proposed community expansion capital projects, which will be constructed in 2020, which are not included in the budget figures contained in Tables 1 and 2. Please confirm which of those costs are for the account of the regulated utility and which costs will be covered by government or customer contributions

Response

The economic feasibility for each community expansion project is derived using the Board's EBO 188 Guidelines. Pursuant to those guidelines and Enbridge Gas' community expansion program, economic feasibility is calculated to ensure that each project is not subsidized by existing customers (i.e., each community expansion project has an expected profitability index (PI) of 1.0). The costs for each community expansion project are recovered through existing rates, the system expansion surcharge (SES), contributions from municipalities and/or First Nations (in the form of tax or levy holidays for a period of time which serves to reduce project costs) and government grants. The contributions to each project are expected to recover all costs associated with each project, inclusive of capital, O&M, taxes, depreciation and return.

The table below lists the community expansion projects for which construction will commence subsequent to Enbridge Gas obtaining all required approvals. The total forecast capital cost and the government grant provided under Bill 32 are provided for each project. Also provided are the forecast present value of contributions from customers (i.e., revenues derived through the SES) and contributions from municipalities and/or First Nations (i.e., avoided costs due to tax or levy holidays).

Project Name	Total Capital Project Cost*	Contribution from Enbridge (Recovered from rates)**	Recovery from System Expansion Surcharge ***	Contribution from municipality or First Nation**	Government Funding (Bill 32) ($Millions)
Cornwall Island Project	$8,418,045	$728,320	$4,037,867	$201,858	$3,450,000
Hiawatha First Nation Project	$5,286,857	$417,407	$1,671,300	$58,150	$3.140,000
Northshore and Peninsula Roads Project	$9,866,268	$506,611	$559,647	$130,010	$8,670,000
Saugeen First Nation Project	$2,510,834	$248,647	$424,447	$37,740	$1,800,000

*The total project capital cost is the present value (discounted) of the gross capital spend

**The contribution from Enbridge includes discounted regular rate revenue as well as the discounted impact of O&M expense, property tax expense, and income tax expense.

***The recovery from System Expansion Surcharge and contribution from municipality & First Nation numbers are discounted to present equivalent dollars.

ENBRIDGE GAS INC.

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

INTERROGATORY

Reference:

Ibid

Question:

Please provide the projected 2020 in-service additions for the capital expenditures shown on these Tables.

Response

The capital expenditure amount in 2020 represents the in-service additions. Also, please see Exhibit I.LPMA.8 b).

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

Ex. B/T3/S1/p. 2

Question:

The evidence states that customers have responded positively to the changes EGI has made to its e-billing practices. Please provide evidence to support this. Please provide copies of all relevant customer research specific to EGI undertaken prior to making these changes.

Response

Enbridge Gas believes that the execution of the customer experience program is the main driver of the increase in NPS. As shown in Figure 5 in the pre-filed evidence, the NPS has experienced a steady upward trend from Q1 2018 to Q4 2019.

Enbridge Gas did not undertake any customer research prior to making the changes to its eBilling practice. Please see Exhibit I.CCC.2.

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

Ex. B/T3/S1/p. 1

Question:

EGI has made e-billing the default billing method for new customers and has switched existing paper bill customers to e-billing for all customers who, for any reason, had previously provided an email address to the Company without prior consent on their part. Did EGI undertake any customer research regarding the decision to switch customers to e-billing without their prior consent? If so, what were the results of this research?

Response

Please see Exhibit I.CCC.1.

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

Ex. B/T3/S1/p. 5

Question:

The evidence states that EGI will continue to develop strategies that increase myAccount adoption to all customers. Please explain the ways in which EGI will increase myAccount adoption.

Response

Enbridge Gas will continue to promote myAccount adoption through ongoing interaction with customers. This includes:

- Utilizing the Interactive Voice Response (IVR) system to promote the availability of self-service for many transactions via myAccount
- Having contact centre agents encourage customers to try the most straight-forward transactions via myAccount
- Having contact centre agents co-browse with customers to navigate through a transaction using myAccount (co-browsing technology allows an agent to view the customer's screen and see exactly what they are seeing to help them navigate)
- Adding new transactions to the virtual assistant (cozE)
- Adding other new and convenient features to myAccount including additional billing/energy use insights

Every time Enbridge Gas interacts with a customer, it is an opportunity to educate them on the features and benefits of myAccount.

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

Ex. B/T3/S1/p. 15

Question:

The evidence indicates that from January 2018 to November 2019 e-billing adoption went from 32% to 57%. To what extent was this adoption related to switching customers without their prior consent?

Response

Information about the number of customers converted to eBill in 2019 is set out in paragraph 38 (Table 1) of Exhibit B, Tab 3, Schedule 1. As explained in paragraphs 35 to 37, Enbridge Gas's 2019 eBill strategy included three core components. One of these was to switch customers who had previously provided an email address from paper bills to eBill. The total number of customers switched was just over 530,000[1]. However, some customers did revert back to paper billing and the 58% adoption rate reflects these losses. After incorporating these losses approximately 11% of the 25% increase in adoption from January 2018 to November 2019 can be attributed to switching customers who had previously provided an email address.

[1] The total number of customers switched is the sum of Union rate zone customers of 171,905 and EGD rate zone customers of 358,384 as shown in paragraph 37 (ii) of Exhibit B, Tab 3, Schedule 1. The number of customers switched in the EGD rate zone was incorrectly shown as 331,480 at paragraph 37 (ii). Enbridge Gas will file a correction to the evidence with the interrogatory response.

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

Ex. B/T3/S1/p. 17

Question:

Please identify when the decision was made to move customers who had provided EGI an email address to e-billing? Was there a business case developed in support of this decision. If so, please provide that business case analysis.

Response

The final decision was made in January 2019.

The overall strategy was developed to deliver savings as contemplated under the MAADs incentive regulatory framework which includes a 0.3% stretch factor. The details of this strategy were documented in a PowerPoint presentation included in the attachment to this interrogatory.

2019

Paperless Strategy

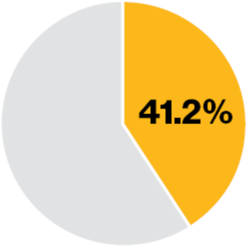
unionGas
An Enbridge Company

ENBRIDGE
Life Takes Energy™

Current **Paperless Status**

Union Gas — An Enbridge Company

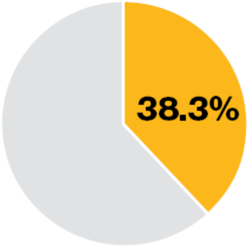
613,000
accounts



Average of
~4% adoption per year.

Enbridge — Life Takes Energy

830,000
accounts



Average of
~4% adoption per year.
2018 on pace for 6%

2019 Common Strategy

New strategy will be aggressive to accelerate adoption.

- Maintain or expand on methods that are currently driving adoption and augment with new strategic initiatives to accelerate adoption rate.
- Built around three core elements:

1. **Default**
   In all customer interactions take the position that paperless is primary option.

2. **Convert**
   Switch existing My Account customers to notify and automatically enroll in Paperless.

3. **Attract**
   Continue to attract customers that we don't otherwise interact with to enroll in Paperless.

2019 Paperless Adoption Plan

	Strategy	Tactics	Target: Union Gas	Target: Enbridge
1	**Default to eBill on all interactions**	All new My Account signups default to eBill	25,000	40,000
		Agent scripting and upsell on all call types	75,000	100,000
2	**Convert active email addresses**	Switch all existing My Account customers to eBill	75,000	100,000
		Solicit email and convert to eBill	25,000	40,000
3	**Promotions and marketing**	Reach customers with no email, no interaction with call centre	25,000	40,000
		New enrollments	**225,000**	**320,000**
		Increase in penetration	**15%**	**15%**

uniongas An Enbridge Company

ENBRIDGE Life Takes Energy™

2019 Paperless Budget Impacts

Tactics	Impact: Union Gas		Impact: Enbridge	
Default new accounts	• Waive $35 new account fee to process move though My Account • Vertex enhancement • Extra staff to handle additional AHT	$250 $100 $25	• Waive $25 new account fee to process move though My Account • SAP enhancement • Additional AHT could negatively impact Call Volume saving with Accenture	$350 $100 $ -
Default call centre interactions	• Agent Incentives • Vertex enhancement for dual billing option	$220 $ -	• Agent Incentives • SAP/Kubra enhancement for dual billing option	$300 $ -
Convert My Account to paperless		$ - $120	• Direct mail to customer with first eBill email to communicate change • Additional call volumes impact savings with Accenture	$ - $ -
Solicit email and convert to eBill	• Extra staff to handle AHT • Vertex enhancement for dual billing option	$60 $ -	• Additional AHT could negatively impact Call Volume savings with Accenture • SAP/Kubra enhancement for dual billing option	$ - $ -
Promotions and marketing	• Email campaigns only to minimize cost to acquire • TBD on use of incentives	$ - $250	• Email campaigns only to minimize cost to acquire • TBD on use of incentives	$ - $250
	Total Budget	**$1,025**		**$1,450**

uniongas An Enbridge Company

ENBRIDGE Life Takes Energy™

2019 Risks & Mitigation

Risk	Mitigations
Increase calls and call handle time that may impact TSF	• Complement all executions with proactive and highly accessible communication plans • Ensure all calls to action lead to digital channels, myaccount • Ensure 2019 call forecasts reflect paperless plans to prevent TSF impacts • Continually refine scripting to ensure delivery is kept as contained as possible • Utilize temp staff as required • Explore implementation of "loyalty team" to minimize impact on other calls
Decreased customer satisfaction	• Make bill delivery choice message clear and accessible • Develop scripting around key benefits for customers • Train staff including Team Lead training to act as specialized escalation prevention • Pilot training and scripting to ensure key messages are well received before full execution rolls out • Leverage Voice of the Customer research to monitor any early on trends or concerns to be addressed
Escalation risks, internal, OEB and media	• Work closely with Ombudsmen/Customer Relations and Public Affairs to ensure any customers upset with the new approach are resolved quickly • Develop key messaging around benefits and continuation of bill choice for use in escalations and media if required
Increased marketing and contact centre costs	• Monitor results and adjust plan as necessary • Use increased funding proportional with savings and results achieved
Data Discrepancies	• Actively work any bounceback or undeliverable emails • Monitor any trends visible once email addresses are used in this new manner • Adjust go forward plans to address any identified trends

uniongas An Enbridge Company

ENBRIDGE Life Takes Energy™

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

Ex. B/T3/S1

Question:

What have been the annual savings achieved by EGI in 2018 and 2019 as a result of the conversions to e-billing? What are the overall savings expected for 2020? Please explain how these amounts were derived.

Response

Savings related to eBill are approximately $10 per customer, which is almost all related to savings for postage. Any savings achieved from avoiding paper bill production costs are offset by electronic imaging, storage and hosting costs.

During 2018, the legacy utilities were operated separately. The practice of converting customers who had provided email addresses was not in place at either legacy utility in 2018, so no savings were achieved from conversions in 2018. However, the legacy utilities would have achieved savings of around $10 per customer for each customer who switched to eBill that year (adjusted for how far into the year when the switch took place).

Enbridge Gas achieved approximately $3.7 million in savings in 2019 from converting customers to eBill. This reflects the fact that savings are not fully effective in the first year as conversions are achieved throughout the year.

Savings expected in 2020 are between $5.5 million and $6.0 million based on what was achieved in 2019. Further savings may be achieved depending on the additional adoption of eBill in 2020.

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

Ex. B/T3/S1/p. 25

Question:

The evidence indicates that Late Payment Charges in 2019 were $18.7 million. Please explain why LPP charges are so high? What is the LPP amount embedded in base rates?

Response

As outlined in the table below, LPP charges in 2019 were in line with the most recent Board-approved amounts embedded in base rates, as well as actual LPP experience in recent years.

($ millions)	Most Recent Board Approved	2018 Actuals
Union Gas (1)	$6.5 (2013)	$7.3
EGD (2)	$10.1 (2018)	$11.9
Total	**$16.6**	**$19.2**

(1) EB-2019-0105 Exhibit C, Tab 2, Appendix A, Schedule 12

(2) EB-2019-0105 Exhibit B, Tab 2, Appendix C, Schedule 5

ENBRIDGE GAS INC.

Answer to Interrogatory from
Canadian Manufacturers & Exporters (“CME”)

Interrogatory

Reference:

Exhibit A, Tab 3, Schedule 1, page 3 of 4

Question:

At Exhibit A, Tab 3, Schedule 1, page 3, EGI states: "To account for certain major capital projects, Enbridge Gas is seeking Board approval of cost allocation methodology changes to the Panhandle System and St. Clair System, Parkway Station and Dawn Station. Enbridge Gas is proposing to implement the cost allocation methodology changes as part of its next rebasing proceeding."

As CME understands it, EGI is looking for the Board's approval of an updated cost-allocation methodology as part of this proceeding, but this new methodology would not be put into rates until EGI's next rebasing. In this regard:

a) Please confirm if CME's understanding of EGI's proposal is correct.

b) To the extent that CME's understanding is correct, is it EGI's view that the issue of cost allocation methodology would already be fully decided and approved by the Board and thus out of scope or unnecessary for the next rebasing application?

c) If the answer to (b) is no, please explain EGI's view on what it believes the Board's role would be during the rebasing application. Please give specific reference to the interaction between any undecided elements of the cost allocation methodology, and those elements that EGI is seeking the Board to approve as part of this application.

Response

a) Confirmed.

b) No. The cost allocation methodologies changes to the Panhandle System and St. Clair System, Parkway Station and Dawn Station may be approved by the Board in this proceeding, but these methodologies would then be part of Enbridge Gas's overall cost allocation study, which is subject to Board review and approval at rebasing. Please see Exhibit I.LPMA.2.

c) Please see Exhibit I.LPMA.2.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Canadian Manufacturers & Exporters (“CME”)

Interrogatory

Reference:

Exhibit B, Tab 2, Schedule 1, page 7 of 31

Question:

At Exhibit B, Tab 2, Schedule 1, page 7, EGI states: "EGD rate zone system renewal capital expenditures are mainly driven by Main Replacements, Meter Exchanges/Replacements, Compressor Equipment, Regulator Refits and Service Relays. Union rate zones system renewal capital expenditures are mainly driven by Stations Replacements, Vintage Pipeline Replacement, the Integrity Management Program, Compression Equipment, and the Meter Exchange Program."

a) Please explain why the drivers of system renewal capital expenditures are so varied as between the EGD rate and Union rate zones.

Response

Please see Exhibit I.BOMA.4.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Canadian Manufacturers & Exporters ("CME")

Interrogatory

Reference:

Exhibit B, Tab 2, Schedule 1 page 17 of 31

Question:

At Exhibit B, Tab 2, Schedule 1, page 17, EGI describes the NPS 30 Don River Replacement Project.

a) Please update the table provided at Energy Probe Interrogatory 16(a) in EB-2018-0305 to include the current proposed Don River Replacement Project Cost. Please also explain any delta between the costs set out in EB-2018-0305 to now.

Response

The project is still in progress and has not yet been completed. There is no change in the estimated project costs as shown in the table in Exhibit I.EP.16 a) in the EB-2018-0305 proceeding.

Please see Exhibit I.VECC.1. In this response Enbridge Gas provides the change request approved by the Board for the Project. In that request Enbridge Gas indicates that there are no changes to the current estimate of project costs.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Canadian Manufacturers & Exporters ("CME")

Interrogatory

Reference:

Exhibit B, Tab 2, Schedule 1 page 18 of 31

Question:

At Exhibit B, Tab 2, Schedule 1, page 18, EGI describes why the NPS 30 Don River Replacement Project has been rescheduled. With respect to the scheduling of the project:

a) When did EGI originally anticipate receiving the necessary permits to proceed with the NPS 30 Done River Replacement, and when were they actually received?

b) What was the original construction schedule?

c) Did EGI investigate the possibility of changing the timing of the customer's planned maintenance shutdown? If so, what was the result of that investigation. If not, why not?

Response

a) Enbridge Gas originally anticipated receiving the permits by December 2018. Different permits were received at various times. The delay of receiving permits resulted in Enbridge Gas adjusting the construction schedule to complete segments in allowable areas as those permits were received. The first segment was permitted in May 2019.

b) Please see Exhibit I.VECC.2.

c) Enbridge Gas could not alter the timing of the planned maintenance shutdowns.

   Enbridge Gas has investigated the possibility of changing the timing of the customer's planned maintenance shutdowns on prior projects and these discussions were also held for the Don River Replacement project. It has been Enbridge Gas' experience in the past that the timing of these planned shutdowns cannot be altered. This was the case for the Don River Replacement project as well. As a result, Enbridge Gas has had to plan and work around the planned shutdowns to ensure that it does not impact the customer's business and operations.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Canadian Manufacturers & Exporters ("CME")

Interrogatory

Reference:

Exhibit B, Tab 2, Schedule 1 page 19 of 31

Question:

At Exhibit B, Tab 2, Schedule 1, page 19, EGI describes the Windsor Line Replacement Project.

a) Please provide a table similar to those provided by EGI at Energy Probe Interrogatory 16(a) in EB-2018-0305 regarding the Windsor Line Replacement Project and the costs both during the leave to construct application, and the current anticipated costs.

Response

Please see Exhibit I.SEC.11.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Canadian Manufacturers & Exporters ("CME")

Interrogatory

Reference:

Exhibit B, Tab 2, Schedule 1 page 20 of 31

Question:

At Exhibit B, Tab 2, Schedule 1, page 20, EGI provides business case summaries for the NPS 30 Don River Replacement Project and the Windsor Line Replacement Project.

a) Please provide the full business cases for the NPS 30 Don River Replacement Project
and the Windsor Line Replacement Project rather than simply the business case summaries.

Response

a) The business case for the NPS 30 Don River Replacement Project can be found at Exhibit C, Tab 1, Schedule 1, Appendix C (Business Case ID: 6423).

   The business case for the Windsor Line Replacement Project can be found at Exhibit C, Tab 1, Schedule 1, Appendix D (AMP ID 212, 913).

ENBRIDGE GAS INC.

Answer to Interrogatory from
Canadian Manufacturers & Exporters (“CME”)

Interrogatory

Reference:

Exhibit B, Tab 2, Schedule 1 page 21 of 31

Question:

At Exhibit B, Tab 2, Schedule 1, page 21, EGI states: "Rather, the Bridge itself would be remediated to ensure structural stability against future flood events. Preliminary discussions identified the need for the use of some kind of sheet pile structures as a permanent remediation for the erosion around the bridge abutments. Based on the sensitivity of the adjacent 1911 (107 year old) twin bell and spigot 30" cast iron sanitary sewer mains (on wood piles), this option was deemed not viable."

a) Was the determination that this option was not viable made by Enbridge, or another stakeholder, such as the City of Toronto, TRCA or Metrolinx?

Response

a) Enbridge Gas determined it was not viable due to the risk associated with working in the vicinity of the twin sanitary sewers.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Canadian Manufacturers & Exporters ("CME")

Interrogatory

Reference:

Exhibit B, Tab 2, Schedule 1 page 21 of 31

Question:

At Exhibit B, Tab 2, Schedule 1, page 21, EGI states: "In addition, from an Enbridge construction and maintenance perspective, the installation of a pipeline on a bridge is deemed to be a last resort."

a) Why are pipeline installation on bridges deemed to be a last resort?

Response

a) Please see Exhibit I.EGDI.Staff.12 from the EB-2018-0108 proceeding which can be found at the following link:

   http://www.rds.oeb.ca/HPECMWebDrawer/Record?q=casenumber:EB-2018-0108&sortBy=recRegisteredOn-&pageSize=400#form1

   In addition to the rationale for avoiding pipeline installation on bridges provided in the response above, pipeline installation on bridges creates several issues not typically found with buried infrastructure. These issues include:

   - Corrosion issues – weather and road salt damages pipe coating leading to corrosion of pipe.
   - Potential damage issues – exposed pipe on bridge structure is subject to damage from debris or other hazards.
   - Maintenance, inspection and repair issues – pipe on bridge structure presents challenges for proper inspection, maintenance and required repairs to the pipe or support systems.

- Vandalism and security issues – exposed pipe on bridge structure is subject to damages from vandalism resulting in security concerns.
- Issues with pipeline supports (hangers and guides) attached to bridge – corrosion resulting in failure of support systems.
- Bucking and bending of pipe issues – pipe hanging on bridge structure experience movement and stress transferred by bridge structure results in pipe damage and possible failure.
- Higher O&M expenses – based on Enbridge Gas experience, there are ongoing maintenance costs associated with pipelines on bridges, especially every three/five years when a full detailed inspection is completed and has resulted in costly refurbishment and repairs of pipe, coating and pipe support systems.

For these reasons Enbridge Gas believes that pipeline installation on bridges are a last resort.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Canadian Manufacturers & Exporters ("CME")

Interrogatory

Reference:

Exhibit B, Tab 2, Schedule 1 page 21 of 31

Question:

a) Please confirm that EGI did not engage in a cost or timeline estimate for any of the other proposed options for the NPS 30 Don River Replacement Project.

Response

a) Confirmed. Please see Exhibit I.EGDI.Staff.12 in the EB-2018-0108 leave to construct proceeding for the Project which can be found at the following link:

http://www.rds.oeb.ca/HPECMWebDrawer/Record?q=casenumber:EB-2018-0108&sortBy=recRegisteredOn-&pageSize=400#form1

ENBRIDGE GAS INC.

Answer to Interrogatory from
Canadian Manufacturers & Exporters (“CME”)

Interrogatory

Reference:

Exhibit B, Tab 2, Schedule 1 pages 25 and 26 of 31

Question:

At Exhibit B, Tab 2, Schedule 1, pages 25-26, EGI states: "Enbridge investigated replacing the entire pipeline including the section that does not have a major leak history and has no active leaks (Remaining Pipeline)

The City of Windsor is planning phased road reconstruction along the Remaining Pipeline which is expected to take place over the coming years. Enbridge plans to complete the replacement of portions of the Remaining Pipeline in phases alongside the municipal roadwork."

a) Please explain why Enbridge would need/plan to replace the Remaining Pipeline at all if it does not have a major leak history and has no active leaks.

Response

a) As stated in EB-2019-0172 at Exhibit C, Tab 3, Schedule 1, pg. 18,

> Enbridge Gas proposes that the Remaining Pipeline be replaced in the future when the integrity risk of this portion of the line becomes a larger concern or when the capacity created by this replacement is required.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Canadian Manufacturers & Exporters (“CME”)

Interrogatory

Reference:

Exhibit B, Tab 3, Schedule 1, pages 2 and 20 of 29;

Question:

At Exhibit B, Tab 3, Schedule 1, page 2, EGI states: "Customers have responded positively to this change and relevant business metrics indicate Enbridge Gas has been successful thus far in both improving customer service and reducing costs."

At Exhibit B, Tab 3, Schedule 1, page 20, EGI states: "As anticipated given the scale of the eBill transition, Enbridge Gas experienced increased call and complaint volume relating to eBilling in 2019."

a) Has EGI conducted customer engagement to determine if the eBilling change, and the method of implementing EGI's eBilling was either:

   i. Desired by customers; or
   ii. Positively received by customers.

b) If the answer to (a) is yes, please provide the results of those customer engagements to the extent that they are not already a part of the record. If the answer to (a) is no, why not?

Response

a)
   i) No
   ii) No

b) Enbridge Gas utilizes a voice-of-the-customer program to regularly monitor customer engagement and feedback. It is not being used to specifically track how customers received the change in eBilling. However, it is used to monitor quality on various transactions and overall Net Promotor Score. Also, please see Exhibit I.Staff.9 a).

ENBRIDGE GAS INC.

Answer to Interrogatory from
Canadian Manufacturers & Exporters ("CME")

Interrogatory

Reference:

Exhibit B, Tab 3, Schedule 1, pages 2 and 20 of 29;

Question:

At Exhibit B, Tab 3, Schedule 1, page 19, EGI states: "While commercial customers have been included within the transition to eBilling, the distribution of customers on eBill skews toward residential customers given they represent the lion's share of Enbridge Gas's customer accounts."

a) Does EGI possess disaggregated data on commercial and/or industrial customers regarding:

   i. The adoption rate of the eBilling system as compared to how many continue to use paper bills; and
   ii. The number of complaints received from these customer segments relative to the number of total customers?

b) If the answer to (a) is yes, please provide that data to the extent that it is not already part of the record.

Response

a)
   i. The adoption rate of eBilling for commercial customers can be found in Table 2 in the pre-filed evidence.

   ii. The information requested is not available.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Energy Probe ("EP")

INTERROGATORY

Reference:

Exhibit B, Tab 2, Schedule 1, Page 4, Tables 1 and 2

Question:

a) Please explain the category of capital expenditures shown in Tables 1 and 2 as Total Overheads.

b) Please explain how the amount of Total Overheads was determined in each table.

c) Please file a table showing the percentage of capital costs that are due to Total Overheads for each year from 2014 to 2023 for the EGD Rate Zone and for the Union Rate Zone.

d) Please explain the differences from year to year and between EGD and Union Rate Zones in the percent of capital costs that are due to Total Overheads.

Response

a) The overheads per rate zone differ between Union and EGD as the utilities each operated under different overhead capitalization policies and processes. Harmonization of overheads will be achieved through the utility integration activities. As noted in the response to an OEB Staff Interrogatory to the EB-2018-0305 Rates Application filed at Exhibit I.Staff.32(c), the category of total overheads is made up the following:

EGD overheads are comprised of four cost components:

- Administrative & General overheads (A&G). A&G are costs that support the delivery of capital projects but cannot be tied directly to a particular project. It is the capitalization of support services based on an approved OEB rate of capitalization for departments such as HR, Finance, and IT, Legal, Executive, Supply Chain, Regulatory, etc.

- Departmental Labour Costs (DLC). DLC are determined by the degree of support each functional group provides directly to capital projects. DLC is generally allocated from Operations and Engineering departments.
- Interest during construction
- Alliance partner overheads

Union overheads are comprised of three cost components:

- Indirect overhead allocations (OH). OH are costs that support the delivery of capital projects but cannot be tied directly to a particular project. It is the capitalization of support services such as HR, IT, Finance, Legal, etc. and direct capital support (Engineering, Operations)
- Alliance partner overheads
- District contractor pre-work costs

b) The total overheads are calculated as the sum of the inputs per rate zone as explained in a) above.

c) Please see the tables below:

Line No.	EGD Rate Zone	2014 Actual	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 Actual	2020 Budget	2021 Budget	2022 Budget	2023 Budget
1	Total Capital	610.1	1,015.3	593.5	427.8	411.6	507.4	517.2	536.0	701.1	493.4
2	Total Overheads	141.3	145.9	156.4	148.1	140.2	151.6	156.8	140.8	143.9	148.4
3	Overhead %	30.1%	16.8%	35.8%	52.9%	51.7%	42.6%	43.5%	35.6%	25.8%	43.0%

Line No.	Union Rate Zone	2014 Actual	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 Actual	2020 Budget	2021 Budget	2022 Budget	2023 Budget
1	Total Capital	482.9	695.2	1,038.2	717.5	513.1	509.6	528.3	746.3	493.5	629.9
2	Total Overheads	68.2	71.5	77.2	78.6	81.0	83.1	76.4	80.0	80.0	80.0
3	Overhead %	16.4%	11.5%	8.0%	12.3%	18.7%	19.5%	16.9%	12.0%	19.3%	14.5%

Note that years 2014-2018 represent capital expenditure and years 2019-2023 represent in-service capital additions These overheads percentages are for illustrative purposes only and do not represent the overheads capitalization rate for ICM projects

d) The overheads per rate zone differ between Union and EGD as the utilities each operated under different overhead capitalization processes prior to amalgamation. Harmonization of overheads will be achieved through the utility integration activities.

The overhead as a percentage of capital projects will fluctuate on an annual basis depending on the amount of in-service capital projects in the year.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Energy Probe ("EP")

INTERROGATORY

Reference:

EB-2014-0219 Report of the OEB – New Policy Options for the Funding of Capital Investments: The Advanced Capital Module, September 18, 2014, p.17. Exhibit B, Tab 2 Schedule 1, Page 10, Table 3

Question:

Please provide the Working Papers for the Rate Zone threshold calculations, including all relevant references and assumptions and explanatory notes

Response

Please refer to the Updated Evidence: 2020-01-15, EB-2019-0194, Exhibit B, Tab 2, Schedule 1, page 10 for Table 3: ICM Threshold Capital Expenditure Calculation by Rate Zone.

Price Cap Index Assumption:

- For the PCI assumption update please refer to the Interrogatory response of the Technical Conference 2019-11-20, EB-2019-0194, Exhibit KT1.2.
- PCI update was updated to 1.61% from 1.66% as stated in original evidence due to Stats Canada revised figures.

Growth Factor Assumption:

- For details of the growth factor calculation for both Rate Zones please refer to Exhibit B, Tab 2, Schedule 1, page 10, Table 4 of the evidence.
- For the inputs required for the growth factor calculation please refer to the evidence Exhibit B, Tab 2, Schedule 1, Appendix B, page 4 and page 8 of the evidence.

Rate Base and Depreciation Expense Assumption

- For the Rate Base and Depreciation details please refer to Exhibit B, Tab 2, Schedule 1, page 13, Table 5 of the evidence.

The detailed 2020 threshold calculation for EGD Rate Zone is presented below:

ICM THRESHOLD CALCULATION (EGD RZ)

ICM Threshold calculation	2018	2020
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	**2018**	
Rate base	6,246	
Rebasing Depreciation Expense	305	
Growth Factor		1.04%
PCI		1.31%
	Base Year	
N - Number of years since rebasing	*1*	2
Calculation of multiplier	-	
i. Growth factor 1st bracket: ((rb/d)(g + PCI * (1 + g)))*		*48.33%*
*ii. Growth factor 2nd bracket: ((1 + g) * (1 + PCI))^n-1*		*102%*
iii. ICM multiplier		*1.59*
2020 ICM Threshold value (ICM multiplier * base year depr'n)		**$ 487.1**

The detailed 2020 threshold calculation for UG Rate Zone is presented below:

ICM THRESHOLD CALCULATION (UG RZ)

ICM Threshold calculation		2013	2020
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**	
Rate base		5,331	
Rebasing Depreciation Expense		239	
Growth Factor			1.54%
PCI			1.31%
		Base Year	
N - Number of years since rebasing		*1*	7
Calculation of multiplier	-		
i. Growth factor 1st bracket: ((rb/d)(g + PCI * (1 + g)))*			*64.10%*
*ii. Growth factor 2nd bracket: ((1 + g) * (1 + PCI))^n-1*			*119%*
iii. ICM multiplier			*1.86*
2020 ICM Threshold value	**(ICM multiplier * base year depr'n)**	**$**	**444.1**

ENBRIDGE GAS INC.

Answer to Interrogatory from
Energy Probe ("EP")

INTERROGATORY

Reference:

EB-2014-0219 Report of the OEB – New Policy Options for the Funding of Capital Investments: The Advanced Capital Module, September 18, 2014, p.20; Exhibit B, Tab 2 Schedule 1, Page 11- Growth factor

Preamble:

ACM Report: *"The value for g is the percentage difference in distribution revenues between the most recent complete year and the approved base year, for ICM requests and for ACM rate rider approvals in a Price Cap IR application. In the first or second IR years following rebasing, a distributor may not have a complete year of data following the cost of service base year. Therefore, for these years, the growth factor may be updated to the difference between the Board approved distribution revenues from the last cost of service application and the most recent complete year prior to the rebasing year."*

Question:

a) For the Union rate Zone the average growth rate from 2013-2018 has been used; for the EGD Rate zone a single year 2017-2018 is used. Please indicate EGI's interpretation of how the ACM Report applies to calculation of the annual growth rates post amalgamation.

b) Please provide the actual annual growth rates for each of Union and EGD for each of the last 5 years and calculate the average for each and the standard deviation.

c) Please provide for each rate zone the growth rates and threshold calculations using

   i) the 5-year average growth rate
   ii) the last complete rate year
   iii) 2019 rate year.

d) Compare the percentages to those filed at Exhibit B, Tab 2, Schedule 1, Appendix B, Page 4 and Page 8.

Response

a) Enbridge Gas has used the Board approved parameters[1], which includes the growth factor, Price Cap index, Rate Base and Depreciation to calculate the ICM materiality threshold for the EGD and Union rate zones.

b) to d).

Not applicable to the current proceeding since the growth factor is being calculated as per the Board policy. See the response to part a) above.

[1] EB-2014-0219 Report of the OEB – New Policy Options for the funding of Capital Investments: Supplemental Report, January 22, 2016; Section 4.2 and Appendix A & Appendix B; EB-2017-0306 and EB-2017-0307 Decision and Order, August 30, 2018

ENBRIDGE GAS INC.

Answer to Interrogatory from
Energy Probe ("EP")

INTERROGATORY

Reference:

EB-2014-0219 Report of the OEB – New Policy Options for the Funding of Capital Investments: The Advanced Capital Module, September 18, 2014, p.22; Exhibit B Tab 2 Schedule 1, Page 14 Eligible Capital Amount Tables 2, 5 and 6.

Preamble:

The ACM Report indicates *"If the forecasted total capital expenditures identified in a Price Cap IR application, are higher than what the distributor documented in its DSP in its previous cost of service application, the distributor needs to document the increases and the reasons for these. This approach is unchanged from the current ICM policy".*

Question:

a) Please provide a version of Table 2 showing Actual and Forecast capital expenditures for 2017, 2018 and estimate for 2019.

b) Please indicate at, a high level, changes from the DSP filed in the EB-2017-0306/0307 amalgamation/rebasing application, including those listed in paragraph 5, and the impact of the changes on the 2018 Rate base.

c) Specifically, indicate the impact of the delays and increase in costs of the Don River Replacement Project on the 2018 and 2019 capital expenditure budgets and the 2020 ICM Threshold.

Response

a) Please find the requested table below, 2017 forecast data is not available.

Line no.	**EGD Rate Zone**	**2018 A**	**2018 F**	**2019 A**	**2019 F**
1	General Plant	47.3	42.9	70.4	66.3
2	System Access	108.9	118.5	151.1	133.2
3	System Renewal	92.3	112.0	110.4	125.1
4	System Service	22.9	17.9	23.9	24.9
5	Total Overhead	140.2	146.5	151.6	135.9
6	**Total EGD Rate Zone**	**411.6**	**437.8**	**507.4**	**485.5**

Line no.	**Union Rate Zone**	**2018 A**	**2018 F**	**2019 A**	**2019 F**
1	General Plant	48.0	47.8	51.8	49
2	System Access	83.5	100.8	104.4	114
3	System Renewal	102.5	107.5	120.1	119.7
4	System Service	198.1	215.3	148.4	181.2
5	Total Overhead	81.0	77.2	83.1	76
6	**Total Union Rate Zone**	**513.1**	**548.6**	**507.8**	**539.9**

Notes – 2018 represents capital expenditure, 2019 represents in-service capital. Excludes Community Expansion and CNG.

b) In the MAADs decision in EB-2017-0306/0307, the Board approved the rate base amount to be used for the ICM threshold determination in the EGD and Union rate zones[1] (see page 33). In the EGD rate zone, the rate base to be used for ICM threshold calculation is the 2018 OEB-approved amount from the Custom IR application. In the Union rate zones, the rate base amount to be used for ICM threshold calculation is the 2013 OEB-approved rate base including the rate base amount for capital pass-through projects during Union's 2014-2018 IRM term. In the MAADs proceeding, the Asset Management Plans for the legacy utilities were provided as part of an interrogatory response and did not support a cost of service application. The difference between the capital amounts included in the Asset Management Plans provided for information purposes in the MAADs application and the amounts that underpin the previously approved rate base amounts for ICM determination is not relevant in this proceeding.

c) Please refer to BOMA 6b) for a summary of the change in costs for the Don River Replacement Project. The main driver for the change is the inclusion of overheads. These costs are included in the annual budgets and do not cause any additional impacts. With the delay of the in-service date for the Don River Replacement

[1] Decision and Order, EB-2017-0306 and EB-2017-0307, August 30, 2018, p.33.

Project (which moved the recognition of the capital expenditures of the project into 2020) Asset Management re-prioritized work, which accommodated $5.3 million of the Don River Project within the 2020 ICM threshold.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Energy Probe ("EP")

INTERROGATORY

Reference:

Exhibit B, Tab 2, Schedule 1, Pages 18 and 19

Preamble:

"Consistent with Enbridge Gas AMP principles, as noted in EB-2018-0305, Exhibit C1, Tab 2, Schedule 1, Page 87 of 1459, 'EGD acknowledges that the identification of risks and the execution of projects is dynamic. As a result, the portfolio is reviewed twice following optimization, to account for execution status, outstanding risks and opportunities, and emerging risks and opportunities. During the year, the project scope may change, or new projects may arise, resulting in cost pressures to the current portfolio. As these pressures are identified, trade-off decisions are made based on risk and available capital, a direct demonstration of EGD's Plan-Do-Check Act model'."

Question:

a) Please file the portfolio list of projects as it was at the time of the EB-2018-0305 and the current portfolio list of projects and explain the changes if any.

b) Please explain the process for identification of risks and file a portfolio risk analysis or a similar report that is presented to management to assist them in investment decisions. If there is no such report, please explain why not and how managers are informed of portfolio risks without it.

c) What is EGD's Plan-Do-Check Act model. Please file a document that explains to employees how to use the model.

d) Please explain how the Plan-Do-Check Act model was used in the Don River Replacement Project.

Response

a) The variances between the Asset Management Plans filed for EGD and Union rate zones respectively in 2018 relative to the planned spend in the 2020 Asset Management Plan Addendum can be found in Exhibit C, Tab 1, Schedule 1, Table 2.1-1 and Table 2.2-1. The projects and other factors that have led to these variances have been articulated in those tables.

b) In establishing the 10-year Asset Management Plans, both legacy EGD and Union performed risk assessments at the project or program level as appropriate and where required in order to prioritize and optimize the work. This process was described in the Asset Management Plans filed by the two companies in 2018 and included in the addendum filed in this proceeding, at Exhibit C, Tab 1, Schedule 1, Appendix A Section 4.2, and Exhibit C, Tab 1, Schedule 1, Appendix B Sections 4.2.1.1.3 and 4.2.1.1.4. Risks are identified and brought forward to the Asset Class Manager on a day-to-day basis and incorporated into the portfolio as appropriate. Example of emerging risks that were recently incorporated into the portfolio are the advancement of the replacement of Hamilton Gate Station ($6 million) and relocation work related to London Rapid Transit ($5.2 million).

c) Plan-Do-Check Act is an underlying principle of striving for continual improvement in the Asset Management Program as well as other management systems across the organization.

   The Integrated Management System (IMS) describes how Enbridge Gas manages its business to be safe and reliable. Specifically, the IMS outlines high-level management expectations which are common across the organization. The Asset Management Program (MP-01) is one of eight Management Programs that comprises Enbridge Gas's Integrated Management System – it provides more detail on how the program meets its regulatory and corporate obligations related to safety and operational reliability. The IMS is predicated on the underlying principle of striving for continual improvement through the implementation of the Plan-Do-Check-Act quality cycle.

   As a model for continual improvement, Enbridge Gas applies the Plan-Do-Check-Act (PDCA) cycle to macro and micro-level activities of the organization. The PDCA cycle outlines the activities that the Asset Management Program performs to ensure that changes are executed effectively, and that continual improvement opportunities are identified.

Plan-Do-Check-Act principles are:

- **Plan**: Establish objectives and processes necessary to deliver results in accordance with expected outcomes and performance targets.

- **Do**: Implement the plan and execute the process.

- **Check:** Monitor the actual results using assessments, internal reviews and audits to compare against the expected outcomes and to ascertain any differences.

- **Act:** Apply corrective and preventive actions on significant differences between actual and planned results. Analyze differences between actual and expected outcomes to determine root causes and how to improve the process.

d) Without defining it as such, the Don River Replacement project has followed the Plan-Do-Check Act model. As can be seen in Exhibit B, Tab 2, Schedule 1, pages 17-19, Enbridge Gas conducted various studies to determine the integrity of the bridge structure, short- and long-term remediation options were identified and executed. During the construction execution phase of the project the PDCA model was also used in addressing a change to the in-service date as illustrated below:

- Plan – original project plan to go in-service Q4 2019

- Do – started the work, encountered permit and land issues/delays

- Check – re-evaluated project plan and risk in relation to in-service timing and submitted Request to Vary

- Act – revised project plan and in-service date to Q2 2020

ENBRIDGE GAS INC.

Answer to Interrogatory from
Energy Probe ("EP")

INTERROGATORY

Reference:

Exhibit B, Tab 2, Schedule 1, Pages 20-22, Table 8

Question:

a) Please provide a table that shows the amounts spent on the Don River Replacement project in 2019 and expected to be spent in 2020.

b) Please provide more details on the almost $10 million increase in Don River Replacement Project costs from that approved in EB-2018-0108.

c) Please Explain the ICM Project Revenue Requirement calculation based on Capex of $26,293 million at Exhibit B, Tab 2, Schedule 1, Appendix E, Page 1.

Response

a) Please see Exhibit I.VECC.4.

b) Please see Exhibit I.BOMA.6.

c) Please refer to Exhibit B, Tab 2, Schedule 1, Appendix E, page 1, Updated 2020-01-15. The ICM revenue requirement calculation is based on a capital expenditure of $30,047,000. An explanation of this capital expenditure amount can be found on page 15, Table 7 and on page 27, Section 4 of the pre-filed evidence Exhibit B, Tab 2, Schedule 1, Updated 2020-01-15.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Energy Probe ("EP")

INTERROGATORY

Reference:

Exhibit B Updated, Tab 2, Schedule 1, Page 23

Preamble:

Energy Probe believes that Incremental Capital Module funding for capital projects should not be used to recover non-incremental costs from ratepayers. Incremental costs are costs that would only be incurred if the project does proceed. Non-incremental costs are costs that would be incurred whether the project proceeds or does not proceed.

Question:

Please provide a detailed cost estimate of the Don River replacement project with supporting calculations for each cost. For each cost please indicate if the cost is an incremental cost or a non-incremental cost.

Response

Please see Exhibit I.CME.3 and Exhibit I.BOMA.6. Based on the definition provided in this interrogatory 100% of the Don River Replacement Project costs were incremental.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Energy Probe ("EP")

INTERROGATORY

Reference:

Exhibit B, Tab 2, Schedule 1, Page 19

Preamble:

"The proposed NPS 6 pipeline is necessary to replace the existing pipeline due to integrity concerns. Results from surveys and inspections conducted as part of the Enbridge Gas Integrity Management Program identified multiple integrity and depth of cover issues which could pose safety and security of supply concern if not addressed."

Question:

a) Please explain the nature of integrity concerns and the year in which they were first raised.

b) Is the Windsor Line the only pipeline in the Enbridge Gas Inc. natural gas distribution and transmission system in Ontario that has integrity concerns? If there are other pipelines with integrity concerns, please file the list of these pipelines, describe the nature of the concerns, and explain the decision process used to prioritize pipeline replacement projects.

c) What are the "surveys" mentioned in the quote? How frequently were these surveys conducted and the length of pipeline surveyed? Were survey reports produced? If not, why not and how were the results communicated to management? If survey reports were produced, please file them.

d) What are the "inspections" mentioned in the quote? How frequently were these inspections conducted and the length of pipeline inspected? Were inspection reports produced? If not, why not and how were the results communicated to management? If inspection reports were produced, please file them.

e) Please describe the Enbridge Gas Integrity Management Program. How are results of the program communicated to management? If Integrity Management reports are produced, please file them. If they are not produced, please explain why not.

Response

a) The need for the replacement of the Windsor Line is being addressed in the EB-2019-0172 leave to construct proceeding. For a description of the integrity concerns associated with the Windsor Line please refer to EB-2019-0172 Exhibit B, Tab 1, Schedule 1, p.1-2. For the timelines associated with the identification of Windsor Line integrity risks please refer to Exhibit I.Staff.2 page 2 in EB-2019-0172.

b) Any specific pipelines that have integrity-related concerns will have mitigation strategies within the previously filed Asset Management Plans for the respective legacy companies. Please refer to Legacy Union Asset Plan section 5.4.1.3 Summary of Pipeline Maintenance Capital Projects Page 82. For Legacy EGD, please refer to the Asset Management plan 2019 section 5.2 Pipe, pages 105-163.

c) Please refer to EB-2019-0172 Exhibit B, Tab 1, Schedule 1, p 1-2 for a description of the surveys and inspections completed on the Windsor Line and their frequency. Please also refer to EB-2019-0172 Exhibit I.Staff.2 p. 2 and EB-2019-0172 Exhibit JT1.19 p. 1 for a summary of results.

d) See response to c).

e) The Enbridge Gas Integrity Management program is based off the Legacy Enbridge Gas Distribution Program which is explained in the 2019 Asset Management Plan, section 5.2 Pipe, pages 105-163 and section 5.3 Stations, pages 164-198, and section 5.4 Storage, pages 199-230. Results of the program are communicated quarterly to management, however these reports are not relevant to the relief being sought in this application.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Energy Probe ("EP")

INTERROGATORY

Reference:

Exhibit B, Tab 2, Schedule 1, Page 19

Question:

a) As a part of the consideration of Prudence of the Windsor Line Replacement project was management presented with a repair vs replace discounted cash flow analysis? If it was, please file a copy of the analysis. If not, please explain why not, and explain how a prudent decision could be made without such an analysis.

b) As a part of the consideration of Prudence of the Windsor Line Replacement project was management presented with an analysis of alternative replacement pipe sizes? If it was, please file a copy of the analysis. If not, please explain why not, and explain how a prudent decision could be made without such an analysis.

Response

a) No. A repair vs replace discounted cash flow analysis was not completed. As indicated in EB-2019-0172, Exhibit B, Tab 1, Schedule 1, page 1-2, the vast majority of the Windsor line is 70-90 years old and the identified integrity risks highlight the extensive concerns on this pipeline that demonstrate it has reached end of life. Coupled with the fact that significant portions of the pipeline have shallow depth of cover (refer to EB-2019-0172 Exhibit I.STAFF.2 page 2 b)) where the only practical and viable solution to the depth of cover issues is replacement, the overall replacement of this pipeline to address all concerns is the most prudent decision.

b) Please refer to EB-2019-0172, Exhibit C, Tab 3, Schedule 1, Appendix 1 for the alternatives reviewed by management for the project.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Energy Probe ("EP")

INTERROGATORY

Reference:

Exhibit B, Tab 2, Schedule 1, Page 23

Preamble:

Energy Probe believes that Incremental Capital Module funding for capital projects should not be used to recover non-incremental costs from ratepayers. Incremental costs are costs that would only be incurred if the project does proceed. Non-incremental costs are costs that would be incurred whether the project proceeds or does not proceed.

Question:

Please provide a detailed cost estimate of the Windsor Line replacement project with supporting calculations for each cost. For each cost please indicate if the cost is an incremental cost or a non-incremental cost.

Response

Please see Exhibit I.VECC.6. Based on the definition provided in this interrogatory 100% of the Windsor Line replacement project costs were incremental.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Energy Probe ("EP")

INTERROGATORY

Reference:

Exhibit B, Tab 2, Schedule 1, Page 23

Question:

a) Please provide a summary update of the capital expenditures and timing of the Windsor Line Replacement project

b) Please Explain the ICM Project Revenue Requirement calculation based on Capex of $80,448 million at Exhibit B Tab 2, Schedule 1 Appendix E Page 2

c) Please confirm there are no incremental revenues from the project.

Response

a) Please see Exhibit I.SEC.11 for a summary update of the capital expenditures of the Windsor Line Replacement project. For the timing of the Project, please see Exhibit I.SEC.12, Attachment 2.

b) Please refer to Exhibit B, Tab 2, Schedule 1, Appendix E, page 2, Updated 2020-01-15. The ICM revenue requirement calculation is based on a capital expenditure of $84,248,000. An explanation of this capital expenditure amount can be found in pre-filed evidence Exhibit B, Tab 2, Schedule 1, page 15, Table 7, Updated 2020-01-15.

c) Confirmed.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Energy Probe ("EP")

INTERROGATORY

Reference:

Exhibit B, Tab 2, Schedule 1, Page 27 - Customer Consultation

Question:

Please provide a copy of the specific Customer Consultation Reports for the Don River Replacement and Windsor Line Replacement.

Response

The reference cited pertains to the Company's overall efforts related to incorporating customer feedback in the services it provides and the investments it makes (including the development of the Asset Management Plan). This is discussed in Exhibit I.STAFF.33 in the 2019 rate proceeding (EB-2018-0305).

In addition to the consultation discussed above, Enbridge Gas, pursuant to the requirements related to a leave to construct application, also conducts extensive consultation with government ministries, cities and municipalities, conservation authorities, Indigenous communities and the general public (i.e., Enbridge Gas customers). The results of this consultation are documented and summarized in the Environmental Report (ER) associated with each leave to construct project.

Consultation activities related to the Don River Replacement project can be found in the ER and the Indigenous Consultation Report (ICR) for the project at the following link:

http://www.rds.oeb.ca/HPECMWebDrawer/Record?q=casenumber:eb-2018-0108&sortBy=recRegisteredOn-&pageSize=400#form1

Consultation activities related to the Windsor Line Replacement project can be found in the ER and the ICR for the project at the following link:

http://www.rds.oeb.ca/HPECMWebDrawer/Record?q=CaseNumber=EB-2019-0172&sortBy=recRegisteredOn-&pageSize=400

ENBRIDGE GAS INC.

Answer to Interrogatory from
Energy Probe ("EP")

INTERROGATORY

Reference:

Exhibit B Updated, Tab 2, Schedule 1, Appendix F, Pages 1 and 2

Question:

a) Please reconcile the 2020 RR for Don River to Exhibit B, Tab 2, Schedule 1, Appendix E, Page 1, line 16.

b) Please reconcile the 2020 RR for Windsor Line to Exhibit B, Tab 2, Schedule 1, Appendix E, Page 2, line 16.

Response

a) The 2020 revenue requirement associated with the Don River Replacement project of \$0.465 million[1] is included in the calculation of the average annual revenue requirement of \$2.048 million[2]. The average annual revenue requirement of \$2.048 million is used in the rate class allocation at Exhibit B, Tab 2, Schedule 1, Appendix F, p. 1.

b) The 2020 revenue requirement associated with the Windsor Line Replacement project of \$(3.616 million)[3] is included in the calculation of the average annual revenue requirement of \$5.648 million[4]. The average annual revenue requirement of \$5.648 million is used in the rate class allocation at Exhibit B, Tab 2, Schedule 1, Appendix F, p. 2.

[1] Exhibit B, Tab 2, Schedule 1, Appendix E, p. 1, column (a).
[2] Exhibit B, Tab 2, Schedule 1, Appendix E, p. 1, column (e).
[3] Exhibit B, Tab 2, Schedule 1, Appendix E, p. 2, column (a).
[4] Exhibit B, Tab 2, Schedule 1, Appendix E, p. 2, column (e).

ENBRIDGE GAS INC.

Answer to Interrogatory from
Energy Probe ("EP")

INTERROGATORY

Reference:

Exhibit B, Tab 2, Schedule 1, Appendix G, Pages 1 and 2

Question:

a) Please reconcile the 2020 RR for Don River to Exhibit B, Tab 2, Schedule 1, Appendix F, Page 1, line 13.

b) Please reconcile the 2020 RR for Windsor Line to Exhibit B, Tab 2, Schedule 1 Appendix F, Page 2, line 12.

Response

a) The 2020 revenue requirement associated with the Don River Replacement project of $0.465 million[1] is included in the calculation of the average annual revenue requirement of $2.048 million[2]. The average annual revenue requirement of $2.048 million is used in the rate class allocation and unit rate calculation at Exhibit B, Tab 2, Schedule 1, Appendix G, p. 1.

b) The 2020 revenue requirement associated with the Windsor Line Replacement project of $(3.616) million[3] is included in the calculation of the average annual revenue requirement of $5.648 million[4]. The average annual revenue requirement of $5.648 million is used in the rate class allocation and unit rate calculation at Exhibit B, Tab 2, Schedule 1, Appendix G, p. 2.

[1] Exhibit B, Tab 2, Schedule 1, Appendix E, p. 1, column (a).
[2] Exhibit B, Tab 2, Schedule 1, Appendix E, p. 1, column (e).
[3] Exhibit B, Tab 2, Schedule 1, Appendix E, p. 2, column (a).
[4] Exhibit B, Tab 2, Schedule 1, Appendix E, p. 2, column (e).

ENBRIDGE GAS INC.

Answer to Interrogatory from
Energy Probe ("EP")

INTERROGATORY

Reference:

Exhibit B, Tab 1, Schedule 1, Appendix C, Page 5, Table 1

Question:

a) Confirm that the major impacts of the current Cost allocation are to Rates T2 and M1/C1 other that are paying too much.

b) Provide an analysis of the impact of the Revised Cost allocation on EGD Rate zone customers that pay the M1/C1 Rate for Dawn Parkway transportation.

c) Provide an analysis of the impact on T2 customers.

Response

a) Confirmed. Rate T2, Rate M12 and Rate C1 have a revenue sufficiency as a result of the 2019 cost allocation study, including the cost allocation proposals. There is also a revenue sufficiency for Rate M9, M10, Rate T3 and the gas supply administration charge.

b) Please see the response at Exhibit I.SEC.8.

c) Please see Exhibit I.STAFF.4 part c) for the estimated in-franchise bill impacts associated with the cost allocation study results, including Rate T2.
Exhibit I.STAFF.4, Attachment 1 provides bill impacts including the cost allocation proposals and Attachment 2 provides bill impacts excluding the cost allocation proposals.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Energy Probe ("EP")

INTERROGATORY

Reference:

Exhibit B, Tab 1, Appendix C, Working Papers, Schedule 3, Page 2

Question:

a) Please confirm that the revised Panhandle cost allocation shows Rates T2 and C1 Firm are currently overpaying.

b) Please show the Impact to these rates based on their total rate revenue.

c) Confirm that currently Rates M1, M2, M4 and M7 are underpaying. Show the relative impact based on total revenue, if these rates were increased.

Response

a) Confirmed. The proposed cost allocation methodology changes for the Panhandle and St. Clair System result in a revenue sufficiency for Rate T2 and Rate C1.

b) Please see Table 1 below.

Table 1
Rate Class Impacts of the Proposed Panhandle / St. Clair
Cost Allocation Methodology Change

Line No.	Rate Class	Current Approved Revenue (1) ($000's)	Proposed Panhandle / St. Clair (2) ($000's)	Rate Class Impact (%)
		(a)	(b)	(c) = (b / a)
1	Rate M1	455,310	5,121	1.1%
2	Rate M2	67,068	1,742	2.6%
3	Rate M4	28,675	3,829	13.4%
4	Rate M7	12,450	1,216	9.8%
5	Rate T2	67,147	(4,886)	-7.3%
6	Rate C1 - Other (3)	30,793	(6,948)	-22.6%

Notes:
(1) Exhibit B, Tab 1, Schedule 1, Appendix C, Table 1, column (a).
(2) Revenue (sufficiency)/deficiency per Exhibit B, Tab 1, Appendix C, Working Papers, Schedule 3, p.1, column (a).
(3) Excludes Rate C1 Dawn-Parkway Transportation Services.

c) Confirmed. Please see part b), Table 1.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Energy Probe ("EP")

INTERROGATORY

Reference:

Exhibit B, Tab 1, Appendix C, Working Papers, Schedule 3, Page 3

Question:

a) Please confirm that Rates M1, M2 are under-paying and M12 are over-paying.

b) Please provide the relative impact on the above rates based on Total Revenue.

Response

a) Confirmed. The proposed cost allocation methodology changes for the Parkway Station result in a revenue sufficiency for Rate M1, Rate M2 and a revenue deficiency for Rate M12.

b) Please see Table 1 below.

Table 1
Rate Class Impacts of the Proposed Parkway Station
Cost Allocation Methodology Change

Line No.	Rate Class	Current Approved Revenue (1) ($000's)	Proposed Parkway Station (2) ($000's)	Rate Class Impact (%)
		(a)	(b)	(c) = (b / a)
1	Rate M1	455,310	(4,535)	-1.0%
2	Rate M2	67,068	(1,543)	-2.3%
3	Rate M12/C1 (3)	252,682	7,775	3.1%

Notes:
(1) Exhibit B, Tab 1, Schedule 1, Appendix C, Table 1, column (a).
(2) Revenue (sufficiency)/deficiency per Exhibit B, Tab 1, Appendix C, Working Papers, Schedule 3, p.1, column (b).
(3) Includes Rate C1 Dawn-Parkway Transportation Services.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Energy Probe ("EP")

INTERROGATORY

Reference:

Exhibit B, Tab 1, Appendix C, Schedule 5

Question:

a) Please indicate for each of the Cost Allocation changes, an assessment of the materiality of each to the Union Rate Zone rate classes and to Ex-franchise customers including EGD Rate zone customers over-paying the M12/C1 rate ($16.9 million?).

b) What advice does EGI have to the Board based on this assessment?

Response

a) Please see Attachment 1 for the cost allocation study directive impacts for each rate class shown as a percent of current approved revenue. The impact for the EGD rate zone for the Rate M12/C1 transportation service is provided at line 23.

   Please also see Exhibit I.STAFF.4 part c) for the estimated bill impacts for Union in-franchise rate classes and Exhibit I.SEC.8 for the estimated bill impacts for EGD rate classes.

b) Please see Exhibit I.STAFF.4 part b).

ENBRIDGE GAS INC.

Impacts of the Cost Allocation Study Directive by Rate Class as Percent of Current Approved Revenue

Line No.	Particulars ($000's)	Current Approved Revenue (1)	Revenue (Deficiency)/Sufficiency: Board-Approved Methodology (1)	Cost Allocation Study Proposals: Panhandle St. Clair (2)	Cost Allocation Study Proposals: Parkway Station (2)	Cost Allocation Study Proposals: Dawn Station (2)	Cost Allocation Study Proposals: Total (1)	Total Impact (1)	Percent of Current Approved Revenue (3): Board-Approved Methodology	Cost Allocation Study Proposals: Panhandle St. Clair	Cost Allocation Study Proposals: Parkway Station	Cost Allocation Study Proposals: Dawn Station	Cost Allocation Study Proposals: Total	Total Impact
		(a)	(b)	(c)	(d)	(e)	(f) = (c + d + e)	(g) = (b + f)	(h) = (b / a)	(i) = (c / a)	(j) = (d / a)	(k) = (e / a)	(l) = (f / a)	(m) = (g / a)
	Union North													
1	Rate 01	197,961	(1,932)	-	(817)	(247)	(1,064)	(2,996)	1.0%	0.0%	0.4%	0.1%	0.5%	1.5%
2	Rate 10	27,412	(4,396)	-	(254)	(77)	(331)	(4,727)	16.0%	0.0%	0.9%	0.3%	1.2%	17.2%
3	Rate 20	27,521	111	-	(131)	(40)	(170)	(60)	-0.4%	0.0%	0.5%	0.1%	0.6%	0.2%
4	Rate 25	2,450	(1,631)	-	(3)	(1)	(4)	(1,635)	66.6%	0.0%	0.1%	0.0%	0.2%	66.7%
5	Rate 100	10,089	(1,156)	-	(3)	(1)	(5)	(1,160)	11.5%	0.0%	0.0%	0.0%	0.0%	11.5%
	Union South													
6	Rate M1	455,310	(3,308)	(5,121)	4,535	135	(451)	(3,760)	0.7%	1.1%	-1.0%	0.0%	0.1%	0.8%
7	Rate M2	67,068	(3,773)	(1,742)	1,543	46	(154)	(3,927)	5.6%	2.6%	-2.3%	-0.1%	0.2%	5.9%
8	Rate M4	28,675	(5,491)	(3,829)	403	12	(3,414)	(8,905)	19.1%	13.4%	-1.4%	0.0%	11.9%	31.1%
9	Rate M5	2,486	(136)	(18)	2	0	(17)	(153)	5.5%	0.7%	-0.1%	0.0%	0.7%	6.1%
10	Rate M7	12,450	(2,916)	(1,216)	274	8	(933)	(3,849)	23.4%	9.8%	-2.2%	-0.1%	7.5%	30.9%
11	Rate M9	1,158	(74)	-	82	2	85	11	6.4%	0.0%	-7.1%	-0.2%	-7.3%	-1.0%
12	Rate M10	20	2	-	1	0	1	3	-10.7%	0.0%	-3.7%	-0.1%	-3.8%	-14.6%
13	Rate T1	11,829	(407)	(644)	220	7	(418)	(825)	3.4%	5.4%	-1.9%	-0.1%	3.5%	7.0%
14	Rate T2	67,147	2,255	4,886	1,452	43	6,381	8,636	-3.4%	-7.3%	-2.2%	-0.1%	-9.5%	-12.9%
15	Rate T3	6,728	234	-	473	14	487	720	-3.5%	0.0%	-7.0%	-0.2%	-7.2%	-10.7%
								-						
	Ex-Franchise							-						
16	Rate M12/C1 - Dawn-Parkway	252,682	24,593	-	(7,775)	98	(7,677)	16,916	-9.7%	0.0%	3.1%	0.0%	3.0%	-6.7%
17	Rate M13	328	(98)	-	-	0	0	(98)	29.8%	0.0%	0.0%	0.0%	0.0%	29.8%
18	Rate M16	920	(744)	738	-	0	738	(6)	80.9%	-80.2%	0.0%	0.0%	-80.2%	0.7%
19	Rate C1 - Other	30,793	(2,228)	6,948	-	0	6,948	4,720	7.2%	-22.6%	0.0%	0.0%	-22.6%	-15.3%
20	Commodity / Admin	8,928	1,971	-	-	-	-	1,971	-22.1%	0.0%	0.0%	0.0%	0.0%	-22.1%
21	Gas Supply and Transportation	593,230	-	-	-	-	-	-	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
22	Total	1,805,184	880	-	-	-	-	880						
	Rate M12/C1													
23	EGD Rate Zone Only	123,082	14,128	-	(3,989)	93	(3,897)	10,231	-11.5%	0.0%	3.2%	-0.1%	3.2%	-8.3%

Notes:
(1) Exhibit B, Tab 1, Schedule 1, Appendix C, Table 1.
(2) Exhibit B, Tab 1, Appendix C, Working Papers, Schedule 3, p.1.
(3) Current approved revenue by rate class excludes gas supply and transportation revenue shown at line 21.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Energy Probe ("EP")

INTERROGATORY

Reference:

Exhibit B, Tab 1, Appendix C, Schedule 6

Question:

Please discuss what if any, adjustment should be made due to the change in Cost Allocation on the S&T transactional Margin and Gas supply Optimization Margin.

Response

Enbridge Gas is not proposing a change to rates for the cost allocation directive as part of this proceeding. Should a change to rates be made, the S&T Transactional Margin is incorporated into the cost allocation results provided at Exhibit B, Tab 1, Schedule 1, Appendix C, Table 1.

Enbridge Gas would not propose a change to the gas supply optimization margin included in rates because any variance between the actual margin and the amount refunded to ratepayers in rates is recorded in the Upstream Transportation Optimization deferral account (179-131).

ENBRIDGE GAS INC.

Answer to Interrogatory from
Energy Probe ("EP")

INTERROGATORY

Reference:

ScottMadden Report, Figure 5, Page 16

Question:

a) Please provide the Statistics for each of the Groups/Lines on the Chart

b) Please provide the least squares trend lines for of the benchmark Utility groups and EGD and Union

c) Please discuss the resulting trends and if the Legacy EGD and Union are reducing UFG.

d) Please compare the average miles of Transmission and Distribution pipe for each group to EGD and Union.

e) Provide a discussion of why Union has much lower UFG, including an analysis of relative # Receipt and Delivery points.

Response

a) Please see Attachment 1.

b) Please see Attachment 1.

c) The statistics reflect that legacy Union Gas and legacy EGD have year-to-year fluctuations in UFG levels that are generally consistent with other gas utilities. Specifically, the R-squared - which measures the degree to which variations in the dependent variable (in this case, UFG levels) can be explained by variations in the independent variable (in this case, time) - does not reflect a strong correlation between changes in UFG levels over time for legacy Union Gas and legacy EGD - consistent with the results of the other benchmark utility groups. The results are consistent with the findings of the Alberta Utilities Commission included in the Report on UFG on page 17. Specifically, the Alberta Utilities Commission states:

> The Commission recognizes that all gas distribution pipeline systems have UFG as an element of operating a natural gas distribution system and that because of the numerous factors that impact UFG, the UFG percentage will fluctuate over time.[1]

d) The average length of pipeline operated by the companies within each comparator group is as follows:

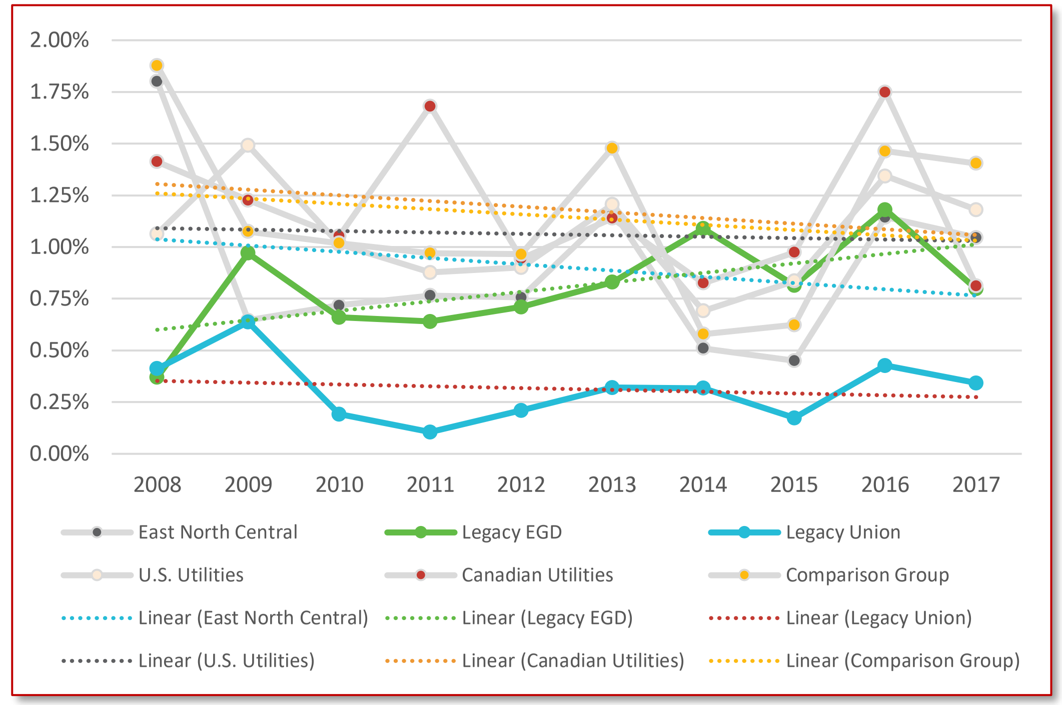
Legacy EGD	39,000 km (24,233 miles)
Legacy Union Gas	70,900 km (44,055 miles)
All investor-owned U.S. gas utilities	8,180 miles
Regional U.S. East North Central Region gas utilities	9,767 miles
Select Canadian gas utilities	26,476 km (16,451 miles)
Comparison group of U.S. gas utilities	13,421 miles

e) Please see Exhibit I.STAFF.28 a) & b).

[1] Alberta Utilities Commission, Decision 22889-D01-2017, 2017-2018 Unaccounted-For Gas Rider D

Year	U.S. Utilities	Comparison Group	East North Central	Canadian Utilities	Legacy EGD	Legacy Union
2008	1.06%	1.88%	1.80%	1.41%	0.37%	0.41%
2009	1.49%	1.08%	0.65%	1.23%	0.97%	0.64%
2010	1.01%	1.02%	0.72%	1.05%	0.66%	0.19%
2011	0.88%	0.97%	0.77%	1.68%	0.64%	0.11%
2012	0.90%	0.97%	0.76%	0.94%	0.71%	0.21%
2013	1.21%	1.48%	1.18%	1.14%	0.83%	0.32%
2014	0.69%	0.58%	0.51%	0.83%	1.09%	0.32%
2015	0.84%	0.62%	0.45%	0.97%	0.81%	0.17%
2016	1.34%	1.46%	1.14%	1.75%	1.18%	0.43%
2017	1.18%	1.40%	1.05%	0.81%	0.80%	0.34%
Average	1.06%	1.15%	0.90%	1.18%	0.81%	0.31%
% of US Average					76.0%	34.8%
% of Regional Average					89.4%	26.5%
% of Canadian Average					68.2%	38.9%

Regression Results	U.S. Utilities	Comparison Group	East North Central	Canadian Utilities	Legacy EGD	Legacy Union
Constant	0.1486	0.5221	0.6171	0.5633	(0.9147)	0.1783
Standard Error	0.5785	0.9396	0.9217	0.7613	0.4449	0.3591
"t" statistic	0.2569	0.5556	0.6695	0.7400	(2.0557)	0.4966
Slope	(0.0001)	(0.0003)	(0.0003)	(0.0003)	0.0005	(0.0001)
Standard Error	0.0003	0.0005	0.0005	0.0004	0.0002	0.0002
"t" statistic	(0.2385)	(0.5434)	(0.6597)	(0.7245)	2.0739	(0.4878)
R-Squared	0.71%	3.56%	5.16%	6.16%	34.96%	2.89%



ENBRIDGE GAS INC.

Answer to Interrogatory from
Energy Probe ("EP")

INTERROGATORY

Reference:

No reference

Question:

a) How many of the Comparator Utilities have Major Storage facilities like Union and EGD?

b) Please provide a discussion whether/how storage Injection Withdrawal and Losses contribute to UFG and if there are differences between Union and EGD.

Response

a) The research and analysis used by ScottMadden did not specifically identify which gas utilities have storage facilities within their service area. The research and analysis focused on six primary sources of UFG, as described on page 19 of the Report:

- Physical losses
- Retail meter variations
- Gate station meter variations
- Theft and non-registering meters
- Company use
- Accounting adjustments

b) Storage injections and withdrawals was not one of the six sources of UFG that was researched and evaluated. This is an item that could contribute to UFG. Please note that the volumes considered for the EGD rate zone for UFG purposes do not include storage injections and withdrawals from the Dawn/Tecumseh operations, because those are upstream of the franchise area.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Energy Probe ("EP")

INTERROGATORY

Reference:

ScottMadden Report, Figure 7, Page 19

Question:

a) Please add Legacy EGD and Union to Figure 7.

b) Please discuss the apparent differences in Measurement Errors and Accounting Issues between the PURA report and the other Sample Utilities and EGD and Union. Which is correct?

Response

a) Please refer to Attachment 1.

b) The Report notes on page 18 that it can be challenging to identify all sources of UFG that would provide for a comparison across gas utilities. Specifically, NRRI states:

> …it is not a straightforward task to measure LAUF [Lost and Unaccounted for] gas. Even after adjusting for measurable factors, uncertainty prevails over the precision of those measurements. LAUF gas has a "black box" element that makes it difficult for state commissions to quantify the effect of individual sources.[1]

Differences in the causes of UFG among utilities may be a result of variations in facilities, systems, processes and procedures. For example, the age and composition of the distribution system may create variations in UFG across gas utilities. In addition, utilities may have varying methods to measure and report UFG. Enbridge Gas has an ongoing process to identify and standardize practices to better monitor and manage UFG across the legacy Companies.

[1] National Regulatory Research Institute (NRRI), Lost and Unaccounted-for Gas: Practices of State Utility Commissions, Ken Costello, June 2013, Executive Summary, page v

Attachment to Energy Probe No. 22

Sources of UFG	*Connecticut PURA Report*	*ATCO Pipelines North*	*SoCalGas and SDG&E*	*Legacy Union*	*Legacy EGD*
Physical Losses	**0.8% – 13.8%**	**8.0% – 10.0%**	**14.0% – 17.0%**	**30.2%**	**18.1%**
Measurement Errors	**10.3% – 16.7%**	**60.0% – 80.0%**	**60.0% – 64.0%**	**13.1%**	**56.9%**
Accounting Issues or Adjustments	**71.5% – 88.0%**	**3.0% – 10.0%**	**5.0% – 8.0%**	**7.7%**	**3.5%**
Theft and Non-Registering Meters	**0.0% – 0.3%**	**2.0% – 6.0%**	**4.0% – 5.0%**	**2.6%**	**0.0%**

ENBRIDGE GAS INC.

Answer to Interrogatory from
Energy Probe ("EP")

INTERROGATORY

Reference:

Scott Madden Report, Figures 8 and 9, Pages 20-21

Question:

a) Why does Union have a small Gate station Variation and EGD a higher Variation?

b) Please provide the relative gate station numbers and volumes.

c) How many of EGD gate stations are also Union Delivery Points?

d) List all EGD Delivery Points/gate stations counterparty and associated Volumes.

e) Please discuss the significance of the differences between Union and EGD

Response

a) Please see Exhibit I.EP.24 c).

b) The relevant gate station is Victoria Square Gate Station as indicated at Exhibit I.EP.24 c). The associated volumes can be found at Exhibit I.FRPO.12, Attachment 1.

c) 7

d) The requested information is confidential data between Enbridge Gas and counterparties.

e) Please see Exhibit I.EP.24 c).

ENBRIDGE GAS INC.

Answer to Interrogatory from
Energy Probe ("EP")

INTERROGATORY

Reference:

ScottMadden Report, Figures 15 and 16, pages 36 and 38

Question:

a) How many Custody Meters does each utility have?

b) Please provide a profile of EGD custody meters - the number, the counterparty and Volumes

c) What are the reasons EGD third party custody meters show higher differences relative to Union.

d) Does ScottMadden have any comments or suggestions how EGD can reduce UFG related to Custody Meters?

Response

a) Legacy Union Gas has 34 custody meters (not including meters at interconnects with Legacy EGD which are no longer custody transfer). Legacy EGD has 3 custody meters.

b) The requested information is commercially sensitive and customer specific and will not be provided.

c) The main reason that Legacy EGD third party custody meters show higher differences relative to Legacy Union Gas meters is the measurement difference at Victoria Square Gate Station. If the measurement difference at Victoria Square Gate Station is excluded, the difference for Legacy EGD is similar to the difference for Legacy Union Gas.

d) ScottMadden does not have any specific comments or suggestions on how Enbridge Gas can reduce UFG related to Custody Meters. It should be noted that gate station meter variations represent differences between custody and check meters and are not necessarily a source of UFG.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Energy Probe ("EP")

INTERROGATORY

Reference:

Scott Madden Report, Conclusion, Page 47

Question:

Going forward, based on the Scott Madden review, what are appropriate EGD/Union Reporting Requirements for UFG?

Response

Enbridge intends to implement all of the recommendations of ScottMadden and continue to identify best practices in all areas of operations (including those related to UFG). Any future reporting of UFG will be pursuant to the Ontario Energy Board's Filing Requirements for Natural Gas Rate Applications. Enbridge Gas expects to report on implementation progress in its 2022 Rates filing.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Energy Probe ("EP")

INTERROGATORY

Reference:

ScottMadden Report, Appendix A, Forecasting UFG, Figure 18, Page 50

Preamble:

The EGD Forecasting Model appears to predict lower UFG than actual.

Question:

a) Please provide the EGD UFG Forecast statistics for the Period 2014-2018.

b) How does this under forecasting affect the UFG payment from customers?

c) Please provide the corresponding Union Forecast vs Actual chart.

d) Discuss the Union and EGD forecasting approaches and recommend any changes (absent settlements and regulatory constraints).

Response

a) The following table shows legacy EGD's OEB-approved vs actual UFG for 2014-2018 IRM period. The forecast of UFG generated by the OEB-approved regression model was lower than actual in each year in this period except 2017.

Legacy EGD Historical Unaccounted for Gas (OEB approved vs. Actual)

Calendar Year	Actual	OEB Approved	OEB Approved vs Actual
2014	135,380	77,660	-43%
2015	88,438	81,519	-8%
2016	133,112	84,766	-36%
2017	93,077	98,279	6%
2018	142,086	106,077	-25%

b) There are two actual-to-forecast variances – throughput volumes and UFG volumes. Any variance between actual and forecast (i.e., OEB-approved) UFG volumes is recorded in the Unaccounted for Gas Variance Account (UFGVA) and cleared to customers as part of the annual disposition of all deferral and variance account balances. In other words, the sum of the OEB-approved UFG forecast reflected in rates and the year-end balance in the UFGVA equals the actual UFG amount for the fiscal year to be recovered from ratepayers.

c) Please refer to the UFG Report, Appendix A, UFG Forecasting, Figure 17 for the legacy Union Gas forecast vs actual UFG chart as well as the attached table.

Legacy Union Year	Actual	Budget	Difference
2013	113,996	70,253	62.3%
2014	97,108	77,325	25.6%
2015	54,407	75,536	-28.0%
2016	131,588	78,340	68.0%
2017	108,901	89,851	21.2%
2018	136,447	79,180	72.3%

d) As stated in the UFG Report on pages 48 and 49, legacy Union Gas' UFG forecast is based on forecasted throughput volumes multiplied by a UFG ratio (currently approved by the Ontario Energy Board for rate-setting purposes to be 0.219 percent). Legacy EGD uses a regression model to forecast UFG which relies on the total number of unlocked customers as its primary explanatory variable to proxy for the size of the distribution system.

Enbridge Gas plans to harmonize the approach for forecasting UFG as part of its 2024 rebasing application. A variety of methodologies used by North American utilities will be evaluated and the methodology that produces the most accurate and reasonable results for the combined utility will be proposed to be used going forward.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Energy Probe ("EP")

INTERROGATORY

Reference:

Exhibit B Updated, Tab 3, Schedule 1, page 17; Negative Option Billing Regulations (SOR/2012-23) https://laws-lois.justice.gc.ca/eng/regulations/sor-2012-23/index.html

Preamble:

"Having achieved 40% overall e Bill adoption by the end of 2018, 2019 was the appropriate time for Enbridge Gas to shift its approach and establish e Bill as the new default option for customers, whether interacting with them online or through Enbridge Gas's contact centres."

Question:

a) Did Enbridge consider the Negative Option Billing Regulations (SOR/2012-23) when it made its decision to change the default option? If the answer is yes, please describe the nature of the consideration including any legal opinions regarding Negative Option Billing Regulations. If the answer is no, please explain why not.

b) If Enbridge obtained any legal opinions regarding the change in the default option regarding the Negative Option Billing Regulations or any other default option legal issues, please file them.

c) Please file document(s) that were presented to Enbridge senior management in support of the decision to change the default option.

Response

a) Enbridge Gas did not consider the "Negative Option Billing Regulations". These are federal (not provincial) regulations, and they do not apply to Enbridge Gas. As can be seen in section 2 of the "Negative Option Billing Regulations", the requirements apply only to "institutions", which are defined as federally-regulated banks, insurance companies and trust and loan companies.

In any event, even if the “Negative Option Billing Regulations” applied to Enbridge Gas (which they do not), these regulations are not relevant to the Company’s decision to make eBill the default option for customers. The “Negative Option Billing Regulations” set out consent requirements to be met before new products or services can be provided to a customer. Enbridge Gas is not providing new products or services to its customers. It is simply changing communication methods. The “Negative Option Billing Regulations” do not speak at all about requirements for methods of billing.

b) Enbridge Gas declines to respond to this question, as the response is protected by solicitor-client privilege.

c) Please see Exhibit I.CCC.5.

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

Scott Madden Report on UFG, page 8

Preamble:

We would like to understand better EGI's previous practices in applying the Supercompressibility Factor to customer meters.

Question:

Please provide the minimum level of pressure that had the Supercompressibility factor applied prior to the recent change in practice.

a) Please provide the settings on instruments for Supercompressibility on EGI customers who received:

   i. Between 120-420 kPa
   ii. Between 420-700 kPa
   iii. Between 700-860 kPa
   iv. Between 860-1380 kPa
   v. Between 1380-1900 kPa
   vi. Above 1900 kPa

Response

The previous and current practice at legacy Union Gas is to change supercompressibility parameters annually in all Electronic Volume Integrators (EVIs) for all pressures. The values of supercompressibility parameters do not depend on pressure.

The previous practice for legacy EGD was that the supercompressibility parameters in EVIs were fixed and never changed. The values of supercompressibility parameters were the same for all pressures: Specific Gravity = 0.5730, N_2 concentration = 1.800%, CO_2 concentration = 0.400%.

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

Scott Madden Report on UFG, page 8

Preamble:

We would like to understand better EGI's previous practices in applying the Supercompressibility Factor to customer meters.

Question:

For each of the above pressure categories, please provide the difference in the adjustment factor between what Enbridge Gas had applied versus what the adjustment factor would be at the minimum pressure of the range specified.

Response

The new practice of changing supercompressibility parameters annually will be applied in 2020 for the EGD rate zone only. The new values of supercompressibility parameters are:

- Specific Gravity = 0.5817
- N2 concentration = 0.465%
- CO2 concentration = 0.262%

The difference between previous and new supercompressibility (adjustment) factors expressed in percentage for minimum pressure of the above ranges are as follows:

Pressure	Difference
120 kPa	0.00%
420 kPa	0.04%
700 kPa	0.08%
860 kPa	0.10%
1380 kPa	0.18%
1900 kPa	0.25%

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

ScottMadden Report on UFG, page 8

Preamble:

We would like to understand better EGI's previous practices in applying the Supercompressibility Factor to customer meters.

Question:

In tabular form, for each of the above pressure categories, please multiply the difference in adjustment factor to the volumes measured from meters whose average pressure throughout the year falls into the respective ranges.

Response

The requested data is not readily available and cannot be completed within the current procedural timelines.

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

Scott Madden Report on UFG, page 13

Question:

Please provide the maximum and minimum allowance differences from Measurement Canada.

Response

The limit of error of the amount of gas supplied is 3% per Electricity and Gas Inspection Regulations, article 46.

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

Scott Madden Report on UFG, page 18

Question:

Please provide the NRRI study or report that supports the statement on UFG.

Response

Please see Attachment 1 for the National Regulatory Research Institute (NRRI) Report No. 13-06 (Lost and Unaccounted-for Gas: Practices of State Utility Commissions) dated June 2013.

Lost and Unaccounted-for Gas: Practices of State Utility Commissions

Ken Costello

Principal Researcher, Energy and Environment

National Regulatory Research Institute

Report No. 13-06

June 2013

8611 Second Avenue, Suite 2C
Silver Spring, MD 20910
Tel: 301-588-5385
www.nrri.org

National Regulatory Research Institute

Board of Directors

About the Author

Mr. Ken Costello is Principal Researcher, Energy and Environment, at the National Regulatory Research Institute. Mr. Costello previously worked for the Illinois Commerce Commission, the Argonne National Laboratory, Commonwealth Edison Company, and as an independent consultant. Mr. Costello has conducted extensive research and written widely on topics related to the energy industries and public utility regulation. His research has appeared in numerous books, technical reports and monographs, and scholarly and trade publications. Mr. Costello has also provided training and consulting services to several foreign countries. He received B.S. and M.A. degrees from Marquette University and completed two years of doctoral work at the University of Chicago.

Acknowledgments

The author wishes to thank the 41 state utility commissions that responded to the survey conducted for this study. He also wants to thank the **Honorable Paul Roberti**, Rhode Island Public Utilities Commission; **Professor Sandy Berg**, University of Florida; **Ron Edelstein**, Gas Technology Institute; **Matt Elam**, Idaho Public Utilities Commission; **Randy Knepper**, New Hampshire Public Utilities Commission; **Paul Metro and Nathan Paul**, Pennsylvania Public Utility Commission; and NRRI colleague **Dr. Rajnish Barua**. Any errors in the paper remain the responsibility of the author.

Executive Summary

Customers of gas utilities pay for more natural gas than they actually consume. The explanation for this discrepancy is what gas utilities and state utility commissions ("state commissions") call "lost and unaccounted-for" (LAUF) gas. LAUF gas, broadly defined, is the difference between the gas injected into a distribution system and the gas measured at customers' meters. Various sources account for LAUF gas, including measurement and accounting errors, stolen gas, and pipe leaks. LAUF gas therefore has both a physical and a nominal component. The cost range of LAUF gas for a typical utility is 2 to 5 percent.

The loss of physical gas (e.g., from leaky pipes) poses a real cost to a utility. The utility, after all, has to purchase additional gas to satisfy the demands of its customers. The nominal component, caused by measurement and accounting error, affects the amounts customers pay for gas relative to the cost of purchased gas for utilities. Accurate LAUF-gas measurements require considerable effort by a utility. State commissions can expect a margin of error in any calculation. They should therefore view a utility's measure of LAUF gas as an estimate rather than an absolute number. This has implications for how state commissions should interpret LAUF gas for taking action.

As part of their obligation, state commissions strive to protect customers by ensuring that utilities control LAUF gas to a reasonable (i.e., prudent) level. Excessive LAUF gas means that customers are paying too much for gas. The Pennsylvania Public Utility Commission estimated that gas customers may be paying as much as $131 million annually for LAUF gas.

Perhaps more important, a high level of LAUF gas may also signal utility negligence in repairing pipes or replacing them, resulting in excessive leaks that could jeopardize safety in addition to inflating costs. Cast-iron and steel piping installed without corrosion-protective measures and certain types of vintage plastic piping are especially prone to leaks from either corrosion or cracking. Gas leaks most frequently do not pose a safety threat because they normally dissipate quickly. Over time, however, aging pipes increase leaks, leading to a possible safety threat. As the NRRI survey showed, commissions have particular concerns regarding upward trends in LAUF gas, since they might signal a pipeline safety threat. Other factors may account for this trend, but it is hard for a utility to discern whether the problem is gas leakage or an increase in measurement error. It seems that utilities, with a push from commissions, should make more effort to locate the specific sources of any increase in LAUF gas.

As a secondary benefit, and one that has gained increased attention, society may also gain environmentally from producing and transporting less gas to meet a fixed level of end-use demand. Overall, LAUF gas has safety, economic, and environmental repercussions for society's welfare.

Challenges for state utility commissions

Commissions face several challenges when interpreting actual LAUF-gas levels. First, some commissions have no single definition of LAUF gas across utilities. A broad definition is the difference between gas delivered to a distribution gas system and gas sold to customers. A more precise and useful definition for commission decision making adjusts the difference for measurable factors, such as company use, temperature and pressure adjustments, and cycle billing.

Second, it is not a straightforward task to measure LAUF gas. Even after adjusting for measurable factors, uncertainty prevails over the precision of those measurements. LAUF gas has a "black box" element that makes it difficult for state commissions to quantify the effect of individual sources. One of these factors is pipe leaks; another is stolen gas. This paper recommends that commissions consider requiring utilities to quantify the effects of different causes of LAUF gas. Although any measurement would fall short of perfect accuracy, it would give most commissions more information than they receive presently from utilities.

Third, different causes account for LAUF gas, including measurement error, accounting error, stolen gas, pipe leaks, third-party damages, line pack, and consumption on an inactive meter. Some of these causes are within a utility's control, while others are exogenous to its influence. The general impression conveyed by some utilities is that they have no or little control over the level of LAUF gas. To the contrary, state commissions need to monitor LAUF gas and not assume that all LAUF gas is uncontrollable and reflects only measurement and accounting errors that pose no real problem requiring corrective action.

Especially important for both state commissions and federal safety regulators is measuring LAUF gas caused by leaky pipes. For various reasons, utilities rarely make this measurement, which admittedly is hard to do. Yet many gas utilities, through the Natural Gas STAR program, are initiating efforts toward reducing gas leakage. These efforts include replacement of bare-steel pipe and replacement or relining of cast-iron pipe.

This study reported on the survey responses of 41 state utility commissions to 14 questions on their policies and practices relating to LAUF gas. These responses cover their ratemaking treatment, oversight activities, evaluation criteria, and incentives for utilities. Part IV highlights the responses, noting that commissions differ as to:

(1) the incentive they give utilities to manage their LAUF gas;

(2) the importance they place on LAUF gas;

(3) their perceptions of the effectiveness of utilities in managing LAUF gas; and

(4) how they evaluate LAUF-gas levels and what criteria they use.

The survey responses show that state commissions do not consider LAUF gas a top priority. Nevertheless, LAUF gas does enter their decisions in rate cases, PGA filings, and safety matters. A number of states—Delaware, Georgia, New York, Pennsylvania, and Texas—have taken proactive positions on LAUF gas. No single reason exists for their actions other than the apparent importance they place on preventing levels of LAUF gas from rising excessively.

This paper reviews current regulatory treatment of LAUF gas. One potential problem is utilities evading responsibility by passing through to their customers the costs of LAUF gas with minimal regulatory oversight. Based on survey responses, several state commissions investigate LAUF-gas percentages only when they exhibit an upward trend or exceed some predetermined level. Otherwise, most commissions seem to assume that all LAUF-gas costs are reasonable. Commissions may consider reevaluating this position.

This paper then identifies alternate regulatory actions to mitigate LAUF gas. Mitigation per se may not serve customer interests if it fails to pass a cost–benefit test. For instance, replacing meters can have a substantial cost that could exceed the benefits from more accurate meter reading and billing. Another example is accelerated pipeline replacement, whose high cost may exceed the economic, safety, and environmental benefits from fewer leaks. Yet, by giving utilities stronger motivation—for example, through explicit incentives, a cap, or systematic monitoring—a commission can help to steer utilities toward a level of LAUF gas that is net beneficial.

This paper also outlines a multi-step regulatory procedure for assessing utility LAUF performance. This general construct draws heavily from a 2010 NRRI paper on the regulatory application of performance measurement and assessment. The procedure involves (1) monitoring LAUF levels, (2) establishing a benchmark, (3) evaluating the utility's performance subsequent to a more detailed inquiry, and (4) taking appropriate action.

Recommendations

This paper provides specific recommendations to state utility commissions on LAUF actions. The major ones are as follows:

1. It would seem inappropriate to compare LAUF-gas percentages across utilities at a given point in time for determining cost recovery and utility prudence.

2. The best benchmark would seem to come from tracking an individual utility's LAUF-gas percentage over time.

3. Utilities can influence LAUF-gas levels in different ways.

4. Commissions may want to be proactive in assessing the performance of utilities in managing LAUF gas, especially for assuring gas customers that utilities are exploiting all prudent actions to manage LAUF gas.

5. Commissions may want to require utilities to compile better information on the individual sources of LAUF gas.

6. Commissions may want to exercise caution in executing an incentive mechanism for LAUF gas.

7. Commissions' most effective tool might be monitoring and assessing utilities' LAUF-gas levels.

Table of Contents

Lost and Unaccounted-for Gas: Practices of State Utility Commissions

I. Purpose of Paper

Lost and unaccounted-for (LAUF) gas is one of those regulatory concepts that draws little attention but has broad implications for regulatory practices. LAUF gas has a multi-dimensional effect: It affects costs and rates, safety, reliability, and the environment. The cost effect is relatively small, but a large volume of LAUF gas can signal a serious safety problem (which, as discussed later, is the biggest concern of state commissions). LAUF gas can also result in methane (CH_4) leakage, posing a greenhouse gas threat, and higher gas losses mean additional gas production to meet a given demand.[1] The U.S. EPA and some environmentalists increasingly have expressed concern over the greenhouse gas effect from LAUF gas.[2] As summarized in a staff report by the Pennsylvania Public Utility Commission:

> Staff conservatively estimates that the total cost of lost natural gas for the companies…is between $25.5 million and $131.5 million per year. The cost of [LAUF] gas is ultimately borne by the ratepayer. Although no distribution system will be able to eliminate all [LAUF gas], it should be minimized. In addition, any natural gas that actually escapes from the system can be a substantial liability to the utility in the form of gas explosions, property damage, and/or loss of life. Safety and reliability go hand-in-hand;[3] methane leakage can pose a serious

---

[1] According to the estimates obtained from the latest U.S. EPA report, total methane emissions throughout the natural gas system as a percentage of total domestic gas consumption are less than 1.5 percent. *See* http://www.epa.gov/climatechange/Downloads/ghgemissions/US-GHG-Inventory-2013-ES.pdf.

[2] Methane is over 20 times more potent as a greenhouse gas than carbon dioxide. The largest source of methane emissions is the natural gas industry. Emissions occur during the production, processing, storage, transmission, and distribution of natural gas. At the distribution level, methane emissions can originate from cast iron and unprotected steel pipes, customer meters, and regulator stations. This paper does not address in any detail the recent concern over the release of fugitive methane throughout the natural gas sector, including distribution. *See*, for example, the U.S. EPA website at http://www.epa.gov/climatechange/ghgemissions/gases/ch4.html; and Tiffany Stecker and ClimateWire, "EPA Should Address Natural Gas Leaks," *Scientific American*, April 4, 2013 at http://www.scientificamerican.com/article.cfm?id=epa-should-address-natural-gas-leaks.

[3] A severe pipe incident, for example, can disrupt gas service for a lengthy period.

greenhouse gas threat, and higher losses mean additional gas production to meet a given demand.[4]

As discussed in the paper, whether a utility should invest large or even incremental sums of money for reducing LAUF gas to achieve economic, safety, or environmental objectives reduces to a cost–benefit question. To say, for example, that a utility should always spend money to achieve environmental benefits, irrespective of the costs, is a nonsensical policy that state commissions should reject out of hand.

LAUF gas also has distributional effects. Utility customers may ask why they should pay for gas they do not consume. This paper attempts to address the following questions in the context of fair and efficient regulation:

1. Should utility shareholders not absorb the costs of LAUF gas, since utilities can control their level?

2. Would fairness, for example, involve both the utility and its customers sharing in the LAUF-gas costs?

3. Would passing through all the costs to customers with minimal scrutiny provide weak incentives for a utility to manage its LAUF gas?

4. Are all LAUF-gas costs beyond the control of a utility, making it fair to pass all of them along to customers?

5. Why should customers not pay for all LAUF gas, since it represents an unavoidable filler between what customers demand and what a utility needs to purchase in meeting that demand (similar to the electric industry, where customer ultimately bear the costs of line losses over transmission and distribution systems)?

As discussed in this paper, commissions should hold utilities accountable for the performance of the distribution systems that they operate and control. Yet, as in other regulatory matters, commissions should balance customer interests with the utility's interest, allowing a utility, for example, to recover all costs that reflect prudent behavior.

Another "fairness" matter relates to LAUF gas caused by measurement error. Assume two customers use the same amount of gas but have different bills. One of them has a temperature-compensating meter while the other does not. Each imposes the same cost on the utility, but the second customer pays more. The second customer surely has a legitimate reason to complain. Bill discrepancies can also result from the two customers having meters of a different vintage—the older meter likely recording gas use with a larger margin of error.

---

[4] Pennsylvania Public Utility Commission, *Unaccounted-for-Gas in the Commonwealth of Pennsylvania*, Joint Report by the Bureau of Investigation and Enforcement and the Bureau of Audits, February 2012, 10 at http://www.puc.state.pa.us/transport/gassafe/pdf/UFG_Report_Feb2012.pdf.

Measurement error, in effect, can allocate LAUF-gas costs to all customers, to the benefit of individual customers. As an example, if the utility under-records usage for certain customers, it would calculate a larger system-wide amount of LAUF gas. The costs for this gas typically would flow through to all of the utility's customers. Those certain customers are receiving discounted, or arguably "free," gas at the expense of other customers. If, on the other hand, the utility over-records usage for some customers, those customers are paying excessively for gas relative to other customers.

This paper includes the survey responses from 41 state utility commissions to 14 questions on their policies relating to LAUF gas (see Appendix A). These policies cover commission ratemaking treatment, oversight, and other activities, evaluation criteria and incentives for utilities. Part IV highlights the responses, noting that (among other things) commission policies differ over (1) the incentive they give utilities to manage their LAUF gas and (2) how they evaluate LAUF-gas levels.

This paper reviews commission practices as to their compatibility with good regulation. The paper recommends that commissions act proactively in monitoring LAUF gas. It also encourages commissions to require that utilities, to the extent possible, quantify the volume of LAUF gas segmented by source. Particularly useful for commissions would be a breakdown of LAUF gas by physical gas losses and measurement error. Physical losses can convey a potential safety threat, while measurement error reflects a potential billing problem or revenue loss.

Part V.D outlines a multi-step regulatory procedure for evaluating utility performance in managing LAUF gas. The major steps include benchmarking, monitoring and taking appropriate action. A commission, for example, can use the information from this procedure to determine cost recovery, to investigate further or implement additional incentives, such as a cost-sharing mechanism, or a hard or soft target.

II. What Is Lost and Unaccounted-for (LAUF) Gas?

A generic definition of LAUF gas is "metered gas receipts minus metered consumption of end-use customers"; that is, it is the difference between the gas injected into a distribution system and the gas measured at customers' meters. The routine operation of a gas utility will inevitably result in LAUF gas if only because of measurement errors, company use, and leaking pipes. Customers of gas utilities therefore pay more for natural gas than they actually consume. As in many other businesses, gas utilities have to buy more of a product than their customers demand. One example of this phenomenon is a grocery store, which because of spoilage buys more fresh fruits and vegetables than are sold.

Various reasons account for the existence of LAUF gas, the primary ones being measurement and accounting errors, stolen gas, and pipe leaks.[5] LAUF gas therefore has both a

---

[5] One commission expert noted that PHMSA identifies at least 17 factors contributing to LAUF gas. *See* Paul Metro, "Technical Losses in Natural Gas Transportation, Distribution, and Storage," presentation to the Energy Agency of the Republic of Serbia, October 2007, 3 at

physical and a nominal component. The composition varies by utility; for example, a utility with cast-iron and bare-steel pipes would tend to lose more physical gas than another utility with polyethylene plastic pipes. LAUF gas is gas that either (1) escapes from the distribution system (e.g., from leaky pipes) or (2) stays in the system but is not reported or measured (e.g., from an accounting error or theft)—thus the term "lost and unaccounted-for gas." The "black box" character of LAUF gas relates to that part which the utility is unable to measure with a tolerable degree of accuracy.

Measurement of LAUF gas is inherently an imperfect estimation process; for example, the utility can only evaluate the accuracy of all meter information within a specified level of tolerance error instead of assuming a definite value. Measurement error causes a discrepancy between measured gas flows and actual flows. The difference can be either positive or negative.[6] The best efforts of a utility can reduce LAUF gas but can never eliminate it. Many gas utilities claim that a large source of LAUF gas is measurement error from the absence of temperature and pressure compensating meters at customer delivery points.[7]

A. Definition of LAUF gas

1. Broad definition

Under this definition, LAUF gas equals R - D, where R equals the volume of gas received by a gas utility ("sendout") and D equals the volume of gas delivered to customers ("disposition"). One definition of disposition is the sum of firm billed sales and company use.[8] A utility may consume gas for compressors, gas processing at storage fields, and gas station heaters. R - D is then the difference between measured quantity of gas entering a gas distribution system and the measured quantity of gas withdrawn by customers, including company use. Another way to express this definition is the "total metered city gate receipts" minus "total metered system deliveries."

This broad definition of LAUF gas makes no adjustments for gas consumed by the utility, pipe leaks, system line pack,[9] measurement and accounting errors, stolen gas, and so forth.

---

http://www.naruc.org/international/Documents/Technical_losses_in_natural_gas_transportation_distribution_storage_Paul_Metro.pdf.

[6] Some utilities report their overall LAUF gas as negative, which means that a negative measurement error overwhelms the physical losses from pipe leaks. Such a result shows that the measured gas volumes entering a gas distribution system are less than the gas delivered to end-use customers.

[7] The staff of the Pennsylvania Public Utility Commission estimated that these meters could cost around $100 each.

[8] Many, if not most, gas utilities exclude company use from the definition of LAUF gas and recover separately the costs in their PGA mechanism.

[9] Line pack increases the volume of gas by increasing the operating pressure of a pipe, thus representing stored gas in a pipeline system resulting from heightened compression. It functions as short-

Because it does not segment LAUF gas by source, both utilities and commissions are unable to diagnose specific problems or take appropriate action. They know only that a certain volume of purchased gas delivered to the distribution system is not consumed by end-use customers.

2. More precise definition

The U.S. Department of Transportation, Pipeline and Hazardous Materials Safety Administration (PMSA)[10] and several gas utilities[11] use the following definition of LAUF gas:

R – D – adjustment,

where "adjustment" is the volume of the gas differential between R and D (as defined above) that is accountable and measurable (*see* Figure 1).[12]

---

term storage to help manage load fluctuations. For example, it represents a temporary source of gas to meet peak demands.

[10] PHMSA requires gas operators in their annual filings to use the following definition:

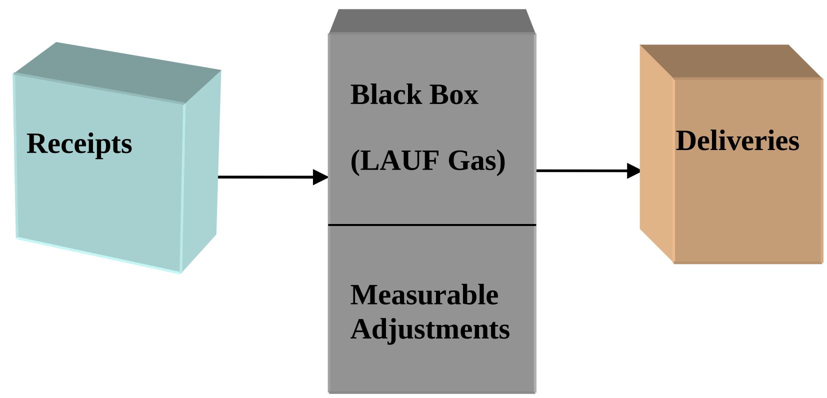
> 'Unaccounted for gas' is gas lost; that is, gas that the distribution system operator cannot account for as usage or through appropriate adjustments. Adjustments are appropriately made for factors as variations in temperature, pressure, meter-reading cycles, or heat content; calculable losses from construction, purging, line breaks, etc., where specific data are available to allow reasonable calculation or estimate; or other similar factors.

(*See* PHMSA - Forms - PHMSA F 7100.1-1 (Instructions for Completing Form.)

[11] A new promulgated rule in Pennsylvania requires a uniform definition of LAUF gas that copies the PHMSA definition (*see* ibid). It defines the LAUF-gas percentage as: [(purchased gas + produced gas) minus (customer use + appropriate adjustments)]/ (purchased gas + produced gas). *See* Pennsylvania Public Utility Commission, Proposed Rulemaking on Establishing a Uniform Definition and Metrics for Unaccounted-for-Gas, October 20, 2012 at http://www.pabulletin.com/secure/data/vol42/42-42/2028.html.

[12] Under this definition, LAUF-gas percentage = $\{[R – (D + \text{adjustment})]/R\}\cdot 100\%$. This paper later uses this definition when referring to targets or standards as regulatory tools for evaluating a utility's performance.

Figure 1: Gas Flows from Receipts to Deliveries



Receipts – (LAUF Gas + Adjustments) = Deliveries,
or
LAUF Gas = (Receipts – Deliveries) – Adjustments
LAUF% = LAUF Gas/Receipts

The major factors affecting LAUF gas are:

1. **Company Use:** Company use includes gas consumed at utility offices and other buildings for space conditioning, water heating, and other purposes. Utilities also use gas as a fuel for compressors, line heaters, and power generation. Typically, a utility will treat company use as "disposition" or similar to gas sales.

2. **Pipe Leakage:** A utility can estimate gas leakage based on (a) known leaks, (2) estimated undetected leaks, and (3) leakage factor per leak. Utilities find it difficult to determine how long a leak has existed and any changes in the leak rate from initial detection to repair. Leakage as a major cause of LAUF gas may translate into an abrupt change in reported LAUF-gas statistics and signal integrity issues on the system. Most utilities verify leakage by detailed leak surveys.

3. **Heat Content:** All gas meters measure volume (e.g., Mcf). The heat content of gas volume measured at the customer's meter usually differs from heat content at the city gates. The reason is that a typical utility has multiple city gates that receive gas from different sources (e.g., pipelines, LNG, waste gas, storage) with differing heat content. The heating value can vary with the quality of gas that enters a distribution system, on a daily basis and among locations. The utility commingles these gas supplies, so the heat content measured at the customer's meter differs from the heat content at the city gates. The heat content for a given measured volume of gas depends on several factors, including the air temperature, atmospheric pressure, and the elevation of the meter. Using a constant heat content to calculate the volume of gas inevitably leads to a measurement error.

4. **Consumption on Inactive Meters:** A utility may fail to turn off a meter once a customer has moved from a house or business.

5. **Temperature and Pressure Adjustment:** Temperature and air pressure affect measured volumes of natural gas. The utility corrects the gas volume at a gate station to a temperature of 60°F at a base pressure of 4 ounces. If the utility fails to make the same correction for gas sold, unaccounted-for gas would result. For every 5°F above or below 60°F, the gas volume will change by about 1 percent. If the average winter temperature is 20°F, for example, unaccounted-for gas would be 8 percent over this period. Temperature-compensated meters can correct the volume.[13]

6. **Billing Inaccuracies:** Without automated metering-reading devices, a utility normally estimates readings every other month.[14] These estimates will not precisely measure actual energy consumption.

7. **Accounting Errors:** One cause is the processing error when the gas accounting department incorrectly measures meter readings. It includes inaccurate calculations, misinterpretation of meter data, and improper accounting for gas receipts and deliveries. The problem lies with a flawed information system.

8. **Third-Party Line Breaks:** The major reason for pipeline incidents is excavation damage by third parties. Constructors or others may dig without first contacting the gas utility to locate pipes. The utility has to repair the facilities in addition to replacing the gas released as a result of the line break.

9. **Theft:** Stolen gas is gas that the utility delivers and customers use but that is not recorded as sales. In other words, stolen gas is gas consumed by an end user but not paid for. Other customers are, in effect, subsidizing delinquent customers. Customers tampering with meters also pose a safety threat to the neighborhood.[15] For most U.S. utilities, stolen gas is trivial in terms of both quantity and revenue losses.

---

[13] Air pressure affects unaccounted-for gas in the following way: A utility purchases gas at four ounces of pressure or the utility corrects the volume to four ounces. As the pressure increases above the four-ounce base, the volume of gas becomes smaller. For every two-ounce change above four ounces, the utility expects a loss of about 1 percent. Therefore, if the service regulators are delivering eight ounces of gas through the end-use meters, the utility can expect around 2 percent unaccounted-for gas; at 10 ounces, the utility can expect around three percent unaccounted-for gas. *See PHMSA - Guides and Manuals - Guidance Manual for Operators of Small Natural Gas Systems* (June 2002 Edition).

[14] Automated meters are expensive, so decision making comes down to a cost–benefit question of whether to install them. One source of LAUF gas is inaccurate gas meters. Determining the overall accuracy of the meters requires testing a random sample of meters. The utility can then extrapolate the average accuracy of the sample meters to all of the meters in its distribution system.

[15] The reader might note, in comparison, that the cost of LAUF gas recovered by a utility represents gas paid for by end users but not consumed (just the opposite of stolen gas) Placed in this light, one might ask why a utility should have its customers pay for LAUF gas. One persuasive answer is that gas losses can be an inevitable part of the gas business, reflecting a legitimate cost of service.

10. **Blowdown:** This practice releases gas into the atmosphere during maintenance, inspections, or emergency procedures. It can pose a safety and environmental problem in addition to wasting gas that the utility has to replace.

11. **Cycle Billing:** This source of LAUF gas derives from gas volumes purchased by a utility not billed to customers over the same accounting period. Cycle billing causes a mismatch between when gas enters the distribution system and when the utility bills it to end-use customers. The utility, for example, might not account for gas purchases and gas deliveries on a common month-end closing date.

12. **Other Measurement Errors:** For example, the distance of straight pipe before an orifice meter can change the measurement accuracy of the orifice-meter device.

A more precise definition of LAUF gas better tracks the sources of gas-volume differentials and thereby gives both utilities and commissions more useful information for interpretation and decision making. For example, estimating the magnitude of gas losses from pipeline leaks requires subtracting total LAUF losses from other sources.

This definition also separates the difference between system "gas input" and system "gas output" into three components: (1) gas used by the utility, (2) accounted-for gas, and (3) unaccounted-for gas. A pertinent question is whether a utility can measure some sources with enough precision for decision making. Gas losses from pipe breaks, for example, are easier to measure than gas losses from pipe leaks, some of which are difficult to locate, let alone measure the gas losses from.[16]

B. The inevitability of LAUF gas

According to PHMSA, pressure and temperature errors in gas measurement rank second to pipe leaks as a contributing factor to LAUF gas. By calculating LAUF gas as a percentage of the total gas purchased, PHMSA claims that the utility can determine whether losses result from leaks or gas-measurement error. Some industry experts dispute this claim, contending that PHMSA's definition of "appropriate adjustment" fails to specify what factors utilities should include in their filings, making it difficult to separate out the effect of pipe leakage. A report by the American Gas Foundation (AGF), for example, argues that:

> Past studies have shown that unaccounted for gas statistics are primarily a result of accounting and measurement errors. Gas lost through leakage to the atmosphere is a comparatively small amount. Also, since the instructions for RSPA Form F 7100.1-1 do not specify what should be included under the 'appropriate adjustments' factor in the percent unaccounted for gas formula, it becomes impossible to extract from the data the amount of gas lost through

---

[16] Leaks generally involve a slow release of gas over a small area, which can go undetected over long periods. Once a utility detects a leak, it can take additional time to confirm the exact location.

> leakage to the atmosphere. [17]…[Thus] unaccounted-for gas information in the [PHMSA] database could not be used as an indicator of the level of integrity, as the data typically contain a heavy proportion of accounting and measurement errors and do not provide reliable information on gas lost through leakage to the atmosphere.[18]

Testimony before the Georgia Public Service paints a different, more optimistic view on measuring the effects of different sources on LAUF gas:

> With the breakdown of measurement losses into the errors or parts that I have described above, a large part of the reason for errors and level of gas loss from each source of error can be estimated with some degree of accuracy. This will allow the corresponding gas loss to be assigned to a specific source. The end result of such assignment of gas loss to specific sources or reasons is to allow [Atlantic Gas Light Company or AGLC] to address these items and to act to reduce the level of [LAUF] on its system.[19]

The residual, or immeasurable, sources constitute truly LAUF gas, as the term implies. They might include only pipe leaks that are difficult to detect and measure, and stolen gas.

C. Utility actions to mitigate LAUF gas

Contrary to the belief of some industry observers, a utility can take a number of actions to manage its LAUF gas:

- Increase measurement accuracy for heat content, and temperature and air pressure adjustments
- Monitor meter accuracy and replace bad meters[20]

---

[17] American Gas Foundation, *Safety Performance and Integrity of the Natural Gas Distribution Infrastructure*, January 2005, 7-2 at http://www.gasfoundation.org/ResearchStudies/CompleteStudy.pdf.Ibid.

[18] Ibid., 8-2.

[19] John W. Mallinckrodt, Direct Testimony, Docket No. 15527, before the Georgia Public Service Commission, July 25, 2002, 8 at http://www.psc.state.ga.us/factsv2/Document.aspx?documentNumber=57096.

[20] Utilities can take a number of actions to minimize the discrepancy between what customers actually consume and what meters record. They include randomly testing and calibrating meters for accuracy, replacing meters when appropriate, maintaining meters and accurately reading meters. Most states have regulations requiring periodic testing of meters. These requirements provide a continuous and systematic check on the veracity of meter reads, which not only produces more "just and reasonable" billings for customers, but also continuously places downward pressure on LAUF-gas percentages.

- Reduce leaks by pipe repair, maintenance and pipe replacement
- Reduce third-party damages by disseminating information to the public of the dangers from digging without first contacting the gas utility to locate pipes[21]
- Reduce "blowdown" during normal maintenance[22]
- Reduce theft
- Match in time the recording of receipts and deliveries

Table 1 lists individual sources of LAUF gas, the problems they cause, and mitigative actions. A utility might find some of these actions not cost-beneficial. Regulators might want to consider requiring utilities to report which of these actions would not pass a cost–benefit test. "Best practices" differ across utilities because each utility faces unique conditions that would change the economics of specific actions to reduce LAUF gas. Thus, what one utility finds tenable, another utility might not.

[21] Typically, state officials have "dig-safe" compliance authority and can impose fines on contractors and others who dig first without notifying utilities through "one call" or "dig safe" notification programs.

[22] As mentioned above, "blowdown" is gas released to the atmosphere from pipe depressurization due to maintenance, inspections, or emergency procedures.

Table 1: Sources of LAUF Gas, Their Problems, and Mitigative Actions

Source	Problem	Mitigative Action
Pipe leaks	▪ High levels or dramatic change in LAUF gas might indicate a safety threat	▪ Continuous monitoring of leaks ▪ Detailed leak surveys ▪ Repair or replace at-risk pipes in a timely fashion
Measurement error ▪ Temperature and pressure difference ▪ Heat value conversion ▪ Meter inaccuracies	▪ Inaccurate gas volumes at customer meters	▪ Testing and calibration of meter accuracy ▪ Replacement or maintenance of malfunctioning meters ▪ Installation of automated meter-reading devices to compensate for temperature and pressure differences ▪ Improved quality of data
Accounting error	▪ Inaccurate calculations and misinterpretation of meter data ▪ Improper accounting for gas receipts and deliveries	▪ Periodic internal audits ▪ Proper staff training ▪ Well-defined standard practices
Company use	▪ Measurable, so it really should fall outside the definition of LAUF gas	▪ Exclusion from LAUF gas and addition to sales
Third-party damage	▪ All customers paying for gas losses and repairs ▪ Safety threat leading to incidents	▪ Proactive program that informs the public of the dangers of digging and calling 811 before digging ▪ Strict penalties (usually imposed by a state agency) for the guilty party ▪ Charges to the guilty party for gas losses and repairs
Cycle billing	▪ Timing mismatch between gas receipts and deliveries	▪ More frequent meter reads (e.g., monthly) ▪ Less accounting lag
Consumption on inactive meters	▪ Waste of gas	▪ Installation of automated meters ▪ Turning off a meter once a customer has moved from a house or business
Stolen gas	▪ All customers subsidizing delinquent customers ▪ Safety threat for local community	▪ Inspection of meters for signs of tampering ▪ Follow-up investigation ▪ Strict penalties for delinquent customers
"Blowdown"	▪ Released gas into the atmosphere during maintenance, inspections or emergency procedures ▪ Potential safety problem	▪ Inject "blowdown" gas into low-pressure mains by adding piping from compressors to the mains

III. Regulatory Concerns and Questions

A. The incentive problem

One concern of commissions is that utilities may have a weak incentive for managing LAUF gas. This problem especially exists whenever a utility is able to pass through LAUF-gas costs to their customers with minimal regulatory scrutiny. As discussed in Part IV, several survey respondents stated that utilities have little or even no incentive to mitigate LAUF gas. Whether or not these observations are valid or even represent a commission's position, the responses do indicate the perception of an incentive problem. Some commissions have tried to elicit better utility performance through explicit incentive mechanisms or the capping of LAUF-gas costs recoverable from customers. Most commissions implicitly have taken the position that it is easier to spread the costs of LAUF gas across all customers than to burden utility shareholders with those costs. The outcome creates little motivation for utilities to control LAUF gas. It also raises a "fairness" question of why utility customers should fully shoulder the burden of costs that are difficult to justify, let alone measure with reasonable accuracy.

The combination of poor incentive for managing LAUF gas and a utility's ability to control LAUF-gas levels seems disjointed from sound regulatory policy. The incentive problem arises from the ease of cost recovery by utilities. Yet, because utilities have some control over LAUF-gas levels, it seems likely that existing levels are above socially optimal levels: Most utilities are not held accountable for poor management of LAUF gas; accentuating this problem is the fact that most utilities also do not benefit when they manage LAUF gas exceptionally well. They might benefit indirectly, however, if a lower level of LAUF gas results in a safer pipeline network or less likelihood of commission scrutiny.

In this environment, the utility's objective would be to minimize risk, or to minimize non-recovery of costs. That is, the major utility motivator is to minimize regulatory risk premised on the fact that it would not benefit from higher performance, even if its customers do. Without the possibility of profit, utilities would therefore have as its major objective the minimization of cost disallowances.

B. Higher purchased gas costs for customers

LAUF gas is one area of regulatory interest in a utility's recovery of purchased gas costs. The others include gas purchasing practices, gas-cost incentives and reconciliation of actual gas costs with cost recovery. Commissions typically consider LAUF-gas costs as part of a utility's cost of service. As with other utility costs, commissions have a duty to customers to evaluate the prudence of utility actions or non-actions in determining whether customers should pay for those costs.

The effect of LAUF gas on purchased gas cost is the product of the average commodity gas cost and the additional level of purchased gas. For example, if the average commodity cost is $5 per Mcf and the utility's "physical" LAUF gas is 1 million Mcf, the additional cost is $5 million.[23] Assuming that the aggregated customer demand is 50 million Mcf of gas, LAUF gas as a portion of total sales is 2 percent; if, instead, the LAUF gas is 3 percent, the additional gas-purchase cost would increase to $7.5 million.

The following relationship illustrates the effect of "physical" LAUF gas on the price that customers pay:

$$\mathbf{P_e = P_w/(1 - lauf\ \%),}$$

where P_e represents the price that customers pay for gas, assuming that the utility recovers all LAUF-gas costs; P_w is the wholesale price of gas, or the price of gas at the city gate; and lauf % is the percentage of metered gas entering a distribution system that the utility does not sell to its customers (i.e., that is physically lost). As an example, assume that the metered gas into a distribution system is 300,000 Mcf, the gas sold is 280,000 Mcf, and utility gas use is 10,000 Mcf. (We are excluding utility gas use as part of LAUF gas.) The LAUF-gas percentage is then [300,000 – (280,000 + 10,000)]/ 300,000 or 3.33 percent. With a lauf % of 3.33 percent and if P_w is $5, P_e would equal $5.17; if lauf % equals 5 percent, P_e would increase to $5.26. The price increase appears small, having little apparent effect on individual customers. Yet, if the utility had to absorb the entire costs, its distribution margins (or shareholders' return) would decline by a much larger percentage. This "tariff" effect might partly explain why commissions: (1) find it easier to pass through the costs of LAUF gas to customers than to have utilities bear the costs; and (2) typically do not disallow the costs of LAUF gas to customers without strong evidence that the utility failed to take appropriate action to mitigate LAUF-gas percentages.

Little evidence is available on the total costs for LAUF gas that utility customers pay. The report by the Pennsylvania Public Utility Commission estimated a wide range of such costs, $25.5-$131.5 million annually.[24] A white paper by the New York State Department of Public Service provides information that the reader can use to calculate that New York customers arguably pay an additional $60 million annually for a statewide LAUF-gas percentage average of 2 percent.[25] A paper by the Conservation Law Foundation estimated that LAUF gas adds $40

---

[23] Some of the measured LAUF gas may result from measurement and accounting error, which does not represent actual physical gas losses that the utility would have to replace for meeting customers' demand.

[24] Pennsylvania Public Utility Commission, *Unaccounted-for-Gas in the Commonwealth of Pennsylvania*.

[25] New York State Department of Public Service, *Staff White Paper on Lost and Unaccounted for (LAUF) Gas* at http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7B0413ECDD-C194-46DE-8B04-AFDB3FBBE404%7D. The paper reported that the state's gas utilities collectively spend around $3 billion for purchased gas (*see* page 6).

million annually to customers' gas bills in Massachusetts.[26]

C. Safety concerns from excessive pipe leaks

Cast-iron and steel piping installed without corrosion-protective measures and certain types of vintage plastic piping are especially prone to leaks from either corrosion or cracking. Utilities often do not consider gas leaks a safety threat because gas from leaks normally dissipates quickly.[27] Over time, however, aging pipes increase leaks, leading to a possible safety threat. As the NRRI survey showed, commissions have particular concerns regarding upward trends in LAUF gas, since they might indicate a pipeline safety threat.

Utilities find it difficult to detect all leaks and measure gas losses. There is no good substitute for detailed leak surveys[28] and follow-up utility actions. These actions include: (1) detecting leaks, (2) repairing leaks, (3) scheduling leaks for future maintenance or pipe replacement (e.g., immediate repair or scheduled longer-term repair), (4) periodic monitoring of leaks, and (5) replacing the highest-risk sections of piping.

Commissions have particular concerns over upward trends in LAUF gas, since they might signal a pipeline safety threat. Other factors may account for this trend, but it is hard for a utility to know if the problem is gas leakage or an increase in measurement error.

---

[26] Shanna Cleveland, "Into Thin Air: How Leaking Natural Gas Infrastructure is Harming our Environment and Wasting a Valuable Resource," November 2012 at http://www.clf.org/static/natural-gas-leaks/WhitePaper_Final_lowres.pdf. The paper added that:

> Every day, thousands of methane leaks are actively releasing one of the most potent greenhouse gas emissions into the air in Massachusetts. Under our current regulations, we do not have an accurate accounting of these emissions, ratepayers cannot easily determine how much of their bill is going towards LAUF, and companies have no incentive to repair leaks unless they pose an immediate hazard. Massachusetts can and should take swift, direct action to change this state of affairs and bring fugitive emissions from distribution pipelines under control."

The paper makes several recommendations. They include (1) establishing leak classification and repair scheduling, (2) setting a cap on recovery for LAUF gas, (3) accelerating pipe replacement programs, and (4) increasing monitoring and reporting requirements. A commission should not take some of these recommendations seriously, since the paper omits any cost estimates for executing them. Would good policy include, for example, spending $100 million on accelerating pipe replacement when (1) a utility has cheaper alternatives available or (2) the societal benefits are much lower?

[27] But if gas leaks migrate to enclosed areas in the presence of ignition sources, a safety risk can quickly escalate.

[28] A leak survey can identify problems that could affect the integrity of a pipe or the operation of the gas distribution system. Utilities normally conduct annual leak surveys of their system. Surveys identify those pipes that pose the highest safety risk, require prompt action or continuous monitoring.

As of August 2, 2011, federal regulations require gas utilities to develop a distribution integrity management program (DIMP). Integrity management focuses on the allocation of utility resources to the areas of greatest risk. DIMP requires a gas utility to take seven major steps:

1. Develop and implement a written integrity management plan
2. Acquire knowledge of the distribution system
3. Identify existing and potential threats
4. Analyze, assess, and prioritize risks
5. Mitigate risk by scheduling safety actions
6. Measure, monitor and evaluate performance, and
7. Report the results

Risk assessment, for example, is a systematic method for determining the probability and consequences of pipeline incidents, such as deaths, injuries and property damage. DIMP requires gas utilities to identify, assess, and prioritize safety risks on a system-wide basis. This discussion points to the possible use of a LAUF-gas metric that isolates the effect of pipe leaks as part of a DIMP review. It can supplement the other information compiled in a DIMP analysis. Without measuring the effects of other sources on LAUF gas, however, the metric becomes a gross number devoid of meaningful interpretation for utility or commission action.

D. The major challenges for regulators

The features of LAUF gas as a performance metric limit its regulatory applications. They make it difficult for commissions to establish a benchmark and elicit better utility performance. The difficulties include:

1. **Definition:** There is no single definition of LAUF gas across utilities, even those located in the same state.[29] The different definitions make it almost impossible for commissions to evaluate a single utility's performance by comparing it with a peer group of utilities. It is like mixing apples with oranges.

2. **Measurement:** Experience so far has shown the difficulty of measuring with reasonable accuracy the effects of individual factors on LAUF gas.[30] Even when

[29] Pennsylvania has recently addressed this problem by enacting a rule that requires a uniform definition of LAUF gas. With utilities using the same definition, the commission believes it would have better information to compare levels and movements of LAUF gas across utilities in the state.

[30] One utility official's testimony, for example, stated that "Some of [the sources of LAUF gas] are difficult to quantitatively identify, or at least separately identify. For example, since most leaks and

factors are measurable, they contain an unknown degree of error; other factors are immeasurable. If LAUF gas dramatically increases from one year to the next, it becomes difficult to know what accounted for the increase.

3. **Multiple Causes:** As mentioned earlier, several causes can account for LAUF gas; for example, measurement error, accounting error, cycle billing, stolen gas, pipe leaks, third party damage, inaccurate meters, and consumption on an inactive meter.[31] Another factor is the composition of facilities that a utility operates. These facilities include distribution, transmission, and storage. Customer composition can also be a factor.

4. **Annual Variability**: The high variability from year to year for some utilities gives support to using a multi-year moving average for benchmarking. If a commission were to set a standard, it should look at a utility's past performance for several years.

5. **Unique Determinants:** LAUF gas, as a percentage of sendout, varies widely across utilities, including those utilities in the same state.[32] Even with a uniform definition of LAUF gas, commissions should expect these variations since each utility faces unique conditions—different pipe age and materials, different meters and regulators, and so forth. Variations exhibit both randomness and events beyond a utility's control (e.g., weather, the business and market environment).[33] Commissions should

---

theft occur within the distribution system and are not measured, their individual contribution to distribution system losses can only be estimated." (W.C. Hamilton, Direct Testimony, on behalf of MichCon, Case No. U-16999, April 20, 2012, 6 at http://efile.mpsc.state.mi.us/efile/docs/16999/0001.pdf.)

On the other hand, another gas utility, Atlantic Gas Light, quantified the effect of different factors on LAUF gas: (a) consumption on inactive meters – 6 percent, (b) main/meter theft – 1 percent, (c) measurement error – 77.21 percent, (d) construction – 0.02 percent, (e) leak related – 14.44 percent, and (f) third-party damage – 1.33 percent. (John W. Mallinckrodt, Direct Testimony, Docket No. 15527, before the Georgia Public Service Commission, 3.)

[31] Ibid.

[32] In Pennsylvania, for example, in 2009, the percentages across nine gas utilities ranged from 0.6 percent to 6.39 percent, with an average percentage of 2.62 percent. LAUF-gas percentages for the large Texas gas utilities range from 0.56 percent to 3.80 percent. LAUF-gas percentages for 15 Massachusetts utilities in 2008 ranged from zero to 2.82 percent. Finally, LAUF-gas percentages for 22 Northeast utilities in 2008 ranged from close to zero to 4.84 percent.

[33] Theoretically, a commission could conduct a statistical analysis that controls for the different factors affecting LAUF-gas percentages. The analysis could identify and measure the important factors explaining percentage differences across utilities. The commission could then better isolate the effect of management competence. The problem is quantifying the effect of individual factors, among other things, because of variations in LAUF-gas definitions, the difficulty of measuring the factors and expected statistical errors. As far as the author knows, no one has attempted such an analysis.

therefore refrain from establishing a LAUF-gas target based on some well-accepted industry practice.

6. **Degree of Control:** Some factors of LAUF gas are within the control of a utility; others are not. For example, a utility can minimize stolen gas by continually reviewing individual gas consumption for individual customers and comparing the customer's most recent consumption to previous periods' consumption. A utility also can minimize gas losses from gas consumption on inactive meters; and gas losses from pipe breaks caused by a third party.

7. **Recognition of Patterns:** It is difficult to forecast LAUF gas for an individual utility, as year-to year levels can fluctuate widely. Statistically, an analyst might mistake a "noise" for a signal (or vice versa) in forecasting a future value for LAUF gas.[34]

IV. Current Regulatory Practices

A. Highlights from the NRRI Survey

NRRI sent out 14 survey questions to state utility commissions in mid-January 2013 inquiring into their policies and practices involving LAUF gas (*see* Appendix A). They cover (1) the incentive they give utilities to manage their LAUF gas, (2) the importance they place on LAUF gas, (3) their perceptions of the effectiveness of utilities in managing LAUF gas, and (4) how they evaluate LAUF-gas levels and what criteria they apply.

NRRI received responses from 41 states (*see* Appendix B). In almost all instances, the commissions answered the 14 questions. Commissions vary widely in their vigilance toward monitoring LAUF gas. Some commissions, for example, devote little effort to reviewing LAUF gas; they allow recovery of their costs with minimal oversight. Other commissions place a cap on allowed cost recovery or apply an explicit incentive mechanism. A third group of commissions routinely scrutinizes levels of LAUF gas to determine cost recovery or to identify any potential safety or other problems. These commissions tend to act when LAUF-gas levels are abnormal or deviate far from historical averages.

One set of responses identified different ratemaking approaches for LAUF gas. They include:

1. Deferral accounts;[35]

---

[34] Noise is something observed in the past that is irrelevant for the future. A signal is also something observed in the past but is a predictor of the future.

[35] One example is for a utility to include LAUF-gas costs in a monthly gas-cost deferral account and then later make an annual true-up. (The commission would authorize the account for tracking gas-cost recoveries.) The utility can base the true-up on the rate-case determined LAUF-gas costs or on the

2. Targeted LAUF-gas percentage in base rates;[36]

3. In-kind gas, especially for transportation customers in which the utility retains a percentage of the gas supplies purchased by the transportation customer;[37]

4. Pass-through costs entirely in the PGA mechanism;[38] and

5. Combined base rate/PGA recovery, which is typical for purchased gas costs.

A recent trend is to shift LAUF-gas costs out of base rates and into the PGA mechanism. Commissions generally allow utilities to include the LAUF-gas costs in their tariffs. Their explanation is that these costs to a significant extent represent a legitimate cost of serving customers.

Highlights of the survey responses follow:

1. **Commissions normally review LAUF gas as part of an audit of a utility's gas-purchasing practices, either in a rate case review or PGA reconciliation.** PHMSA also requires annual reporting of LAUF gas by utilities. Although a topic in various dockets, LAUF gas rarely receives major attention.

---

actual LAUF-gas costs over the past 12 months. The latter treatment recognizes that the actual costs for any given year could be greater or smaller than the allowable true-up costs.

[36] An example is a commission allowing a utility to collect all of its LAUF-gas costs as long as the LAUF-gas percentage does not exceed 3 percent. The utility would absorb any LAUF gas above that percentage.

[37] This approach is similar to FERC's for gas consumed by gas pipelines in their operations as fuel and LAUF.

[38] State commissions have traditionally approved cost trackers, such as PGA mechanisms, only under "extraordinary circumstances." Commissions recognize the special treatment given to costs recovered by a tracker; they consider cost trackers an exception to the general rule for cost recovery. Thus, this position places the burden on a utility to demonstrate why certain costs require special treatment.

The "extraordinary circumstances" justifying most of the cost trackers that commissions have historically approved have been for costs that are: (1) largely outside the control of a utility, (2) unpredictable and volatile, and (3) substantial and recurring. Historically, commissions required that all three conditions exist if a utility wanted to have costs recovered through a tracker. Fuel costs were a good candidate because of their influence by factors beyond the control of a utility, their volatility, and their large size. Commissions recently have approved cost trackers when not meeting all three conditions, especially the third (substantial and recurring costs). Recovery of LAUF gas through the PGA or a special tracker appears not to meet all three conditions: Utilities have some control over LAUF-gas costs, and these costs, although recurring, are not substantial.

2. **Several commissions do have concerns when LAUF gas increases from historical levels or exhibits a sudden jump from a previous period.**
   A recent increase can indicate, for example, a greater number and severity of pipe leaks posing a safety threat. Commissions are more likely to scrutinize a utility's LAUF gas because of a dramatic increase rather than the absolute level itself. Observing, for example, a LAUF-gas level of 5 percent conveys little information in the absence of a benchmark or comparison with the utility's previous performance or other utilities' performances.

3. **Few commissions give utilities explicit incentives to control LAUF gas.**
   A few utilities have special incentive mechanisms for LAUF gas; for example, New York gas utilities and Chesapeake Utilities in Delaware. In New York, the commission sets a target that is a fixed percentage above sales.[39] For Chesapeake Utilities, the mechanism provides no explicit rewards and penalties, yet it can trigger further commission review or even a penalty if the utility fails to explain why its LAUF gas has grown. A small number of commissions impose a penalty on a utility for failing to achieve a predetermined target; for example, they impose a cap on a LAUF-gas percentage above which the utility is unable to recover costs.[40] Other commissions provide fixed-cost recovery in base rates. While this treatment gives utilities strong incentives for controlling LAUF, commissions have moved away from it because of a possible large gap between actual and predicted LAUF-gas costs. Several commissions indicate that they would initiate an investigation when LAUF gas reaches "abnormally high" levels.[41] Some respondents also indicated that PHMSA pressures state commissions to act when LAUF-gas percentages exceed certain levels. A few instances occurred in which a high LAUF-gas percentage caused a commission to impose a cap to motivate the utility to repair its pipe leaks or replace its leaky pipes.

4. **The strongest incentive for utilities to manage LAUF appears to lie with the increased likelihood of a pipeline incident if they ineffectively repair or eliminate leaks.**
   A surprisingly large number of survey respondents say that utilities have no incentive to manage their LAUF gas. This may be an overstatement because, even if commissions provide no direct incentives, high LAUF-gas levels may indicate a

---

[39] New York did not respond to the survey, but this information came from a white paper cited in footnote 24. The target is a hard cap in the form of a range of values outside of which the utility receives either a penalty or reward.

[40] The Texas Railroad Commission, for example, sets a cap of 5 percent. *See* Texas Railroad Commission, *Final Order*, GUD No. 10112, June 6, 2012, 2 at http://www.rrc.state.tx.us/meetings/gspfd/10112-FinalOrder.pdf.

[41] Part V of this paper suggests how a commission can detect abnormally high levels of LAUF gas.

potential safety problem that a utility would want to address. Besides, PHMSA acts as a backstop when LAUF gas seems excessive.[42] Pipeline incidents can have severe financial and public-image repercussions for a utility. Therefore, a utility would likely go to great lengths to avoid an incident.[43]

5. **Several commissions continuously monitor LAUF gas, largely to detect high leakage levels.**
   Their chief concerns are that high levels might reflect a safety threat or customers paying excessively for purchased gas. Typically, commission staff would review historical levels of LAUF gas for a single utility and conduct a more detailed investigation when the most recent level is abnormally high.

6. **More commissions compare a utility's LAUF-gas percentage with its historical levels rather than with other gas utilities' percentages.**
   Commissions seem to recognize, rightly so, that a more meaningful comparison is with a utility's previous performance than with other utilities' LAUF-gas percentages.[44]

7. **LAUF-gas percentages depend heavily on the age and types of pipes.**
   Older plastic pipes, cast-iron pipes, and bare steel tend to have more serious leakage problems. Some respondents noted that utilities in areas with newer pipes have lower LAUF-gas percentages and stricter targets imposed upon them by commissions. A worthwhile study would be to collect empirical evidence on whether the first part of the previous statement is true.

8. **Almost all state commissions allow the recovery of LAUF-gas costs in a PGA mechanism.**
   Similar to purchased gas costs, the base rates of many utilities include historical or projected LAUF-gas costs with any deviations recoverable in a PGA. Utilities, in their PGA mechanisms, generally divide the total gas-purchased costs by the volume of gas sold to customers.[45] As an example, assume that a utility spends $50 million to purchase 10 million Mcf of gas, or $5 per Mcf. Assume also a LAUF-gas percentage of 5 percent. The utility is then recovering $50 million from customers for 9.5

---

[42] According to one of the survey responses, after finalizing the RSPA Form F-7100.1 each year, typically PHMSA will request that the commission follow up on the utilities that report above 5-percent lost gas.

[43] On the other hand, a utility might also be in a budget-cutting mode that compromises safety. Another reason is a lax safety culture within the utility that could lead to negligence.

[44] See the discussion in Part III.C.

[45] By calculating the PGA mechanism based on sales, the utility is implicitly building in the LAUF-gas factor.

million Mcf of sales (with 0.5 million Mcf of LAUF gas), or $5.263 per Mcf of gas sold. Customers are, in effect, paying $0.263 more per Mcf of gas (or about 5 percent) to compensate the utility for LAUF gas. The PGA mechanism acts as a true-up mechanism that allows a utility to collect its LAUF-gas costs not recoverable in base rates. The rationale for LAUF-gas cost recovery in the PGA mechanism is that: (a) because LAUF gas is volatile from year-to-year, it is hard to predict, and (b) the commodity costs associated with LAUF gas are beyond the control of a utility.

9. **One topic of interest in a number of states is allocating LAUF-gas costs between different customer groups.**
   These customers include firm sales customers, interruptible customers and transportation customers. Many utilities require transportation customers to compensate them with in-kind gas. These customers would therefore purchase additional gas to offset the lost gas. The utility would then retain the gas.[46]

10. **Several state commissions expect utilities to take reasonable steps—infrequently based on a cost-benefit criterion—to manage LAUF, especially to avoid a public safety threat.**
    This regulatory posture places faith on the judgment and actions of utility management to avoid a pipeline incident.

11. **Many gas utilities have recently embarked on accelerated pipeline-replacement programs that should lower the amount of LAUF gas in the future.**
    These efforts should lower LAUF gas over time but are not necessarily cost-effective. Some commissions consider pipeline infrastructure surcharges[47] as critical in reducing LAUF gas by removing any disincentives for a utility to replace its pipes. A future study should look at whether the accelerated pipeline-replacement programs,

[46] This approach is similar to FERC's treatment of LAUF gas: Transportation customers reimburse most pipelines for in-kind for gas consumed by the pipelines in their operations. Typically, pipelines retain a percentage of the volumes of gas requested by customers for transportation. FERC has a policy of allowing pipelines the option to establish either: (a) a fixed percentage in a rate case that remains in effect until its next rate case, or (b) a percentage that could change on a periodic basis (e.g., annually) along with a true-up mechanism. (*See* ANR Pipeline Co., *110 FERC ¶ 61,069*, 2005.)

[47] Infrastructure surcharges come under different labels: For example, capital expenditure tariff tracker (Rhode Island), utility enhancement infrastructure rider (Michigan, New Jersey), accelerated main-replacement program (Indiana, Kentucky), infrastructure replacement rate surcharge (Georgia, Kansas, Missouri, Nebraska), interim rate adjustments/rate-stabilization tariff (Texas, Virginia), main-replacement program rider (Arkansas), and cast-iron bare-steel replacement program (New Hampshire). A general definition of surcharges is that they represent an adjustment to the customer bill that raises rates by a specified amount for a limited time. *See* Paul Roberti, "Regulatory Efforts to Enhance Pipeline Safety," presentation at the AGA Reauthorization and Transmission Pipeline Design, Construction and Operations Workshop, February 29, 2012, 8.

which have proliferated in recent years,[48] have reduced leaks and the level of LAUF gas.

12. **Unless the level of LAUF gas indicates a safety threat, utilities generally place low priority on LAUF-gas management.**
    Which of the actions that utilities can take to lower LAUF gas would be cost-beneficial is unknown. A few survey responses indicate the use of a cost–benefit criterion but give no further detail.

13. **While the vast majority of survey respondents expect utilities to reasonably manage their LAUF gas, few have an opinion as to whether utilities could do a better job.**
    Most respondents found no fault with their utilities' performance.[49] Some added that their oversight would enable them to detect and remedy any serious problems. A few respondents contend that utilities should have self-motivation to manage their LAUF gas.

14. **Commissions seem to interpret a higher LAUF-gas percentage over time as an indicator of possible excessive leaks.**
    The burden then falls on the utility to take action or provide evidence that the higher LAUF-gas percentage does not indicate growing pipe leaks that pose a public safety risk.

15. **Most commissions reported that utilities in their state use the same definition for LAUF gas and ratemaking treatment of LAUF-gas costs.**
    Exceptions exist, especially for the definition of LAUF gas.

16. **Utilities generally do not break down LAUF gas by source, at least in quantitative form.**
    Much more commonly, utilities provide a litany of possible sources. In other words, frequently utilities will only report to their commission the sources without quantifying their effects or suggesting cost-effective mitigation actions. Sometimes, a utility would report lost gas from third-party damage or gas use for internal operations. Probably the best source for a breakdown of the sources is the annual

[48] *See* U.S. Department of Transportation, *Pipeline and Hazardous Materials Safety Administration, White Paper on State Pipeline Infrastructure Replacement Programs*, December 2011 at http://opsweb.phmsa.dot.gov/pipelineforum/docs/PHMSA%20111011-002%20NARUC.pdf.; and American Gas Association, "Infrastructure Cost Recovery Update," *Natural Gas Rate Round-Up*, January 2012. The last publication noted that "currently, more than 40 utilities in 19 states serving 20 million residential natural gas customers are using full or limited special rate mechanisms to recover their replacement infrastructure investments, and 6 utilities have such mechanisms pending in 3 other states" (p. 1).

[49] Consequently, these commissions require no incremental actions by utilities to reduce LAUF gas. They presumably perceive utility performance as satisfactory in reflecting prudent utility behavior.

report that utilities must file with PHMSA, namely Form F-7100.1.[50] A commission might speculate from the aggregated level of LAUF gas that leaks are excessively high. If so, the commission might then require additional information from the utility or conduct its own investigation. A key policy question is whether commissions should require utilities to quantify the effect of individual sources on the level of LAUF gas.

17. **Utilities generally report their LAUF gas in different venues.**
    They include PGA filings, audits of a utility's gas procurement practices, supporting evidence in a rate case, EIA-176 filings[51], and the annual report to the commission or PHMSA.

18. **The information necessary to compile LAUF-gas percentages by utility over an historical time frame is publicly accessible.**
    The percentages are sometimes in a summary or tabular form, while in others interested parties can compute percentages from different sources.

19. **Commissions generally do not publicly report the effect of LAUF gas on purchased gas costs.**
    Multiplying the LAUF gas by the average commodity-gas cost can produce the calculation. A few survey respondents mentioned that the additional purchased gas costs from LAUF gas are minimal.

20. **Several commissions monitor LAUF gas in a rate case, or a PGA filing.**
    Often they will compare the most recent LAUF-gas percentages with earlier ones to detect any trends. For example, they might examine whether LAUF gas has grown over the past two or three years.[52]

---

[50] 49 CFR Part 191 requires gas operators to annually file *Form F-7100.1* with PHMSA. Failure to report can result in a civil penalty. Part G, Percent of Unaccounted for Gas, states that:

> 'Unaccounted for gas' is gas lost; that is, gas that the operator cannot account for as usage or through appropriate adjustment. Adjustments are appropriately made for such factors as variations in temperature, pressure, meter-reading cycles, or heat content; calculable losses from construction, purging, line breaks, etc., where specific data are available to allow reasonable calculation or estimate; or other similar factors.

[51] The U.S. Department of Energy requires gas utilities to provide annual information in *EIA-176*, which reports by state (a) losses from leaks, damage, accidents or blowdown and (b) unaccounted for gas, defined as the difference between the sum of gas supply and the sum of gas disposition; this difference, as noted by EIA, is mostly attributable to accounting and measurement errors. For several states, the second component is negative. EIA publishes this information in its *Natural Gas Annual,* Appendix A at http://www.eia.gov/naturalgas/annual/.

[52] For one utility, for example, the Idaho Public Utilities Commission retained a cap on LAUF gas until the utility demonstrated its mitigation actions.

B. Examples from selected states

A number of states and utilities stand out in their practices relating to LAUF gas. They are Chesapeake Utilities, Atlanta Gas Light, Idaho, Indiana, Michigan, New York, Ohio, Oklahoma, Pennsylvania and Texas (Table 2 highlights their actions). Other commissions and utilities might want to study them and consider applying them for their own use.

Table 2: Selected Activities and Practices Involving LAUF Gas

State/Utility	Activities/Practices
Chesapeake Utilities	• Unaccounted for Gas Incentive Mechanism, whose purpose is to reduce LAUF gas below a predetermined benchmark. The mechanism provides no explicit rewards or penalties but triggers a commission review if the LAUF-gas percentage exceeds the higher bound of the specified dead band. (Chesapeake Utilities Corporation, Delaware Division, *Rules and Regulations Governing the Distribution and Sale of Gas*, September 2, 2008 at http://www.chpkgas.com/wp-content/uploads/2012/09/DE_Tariff-Nov-5-2012.pdf.)
Atlanta Gas Light	• Minimum LAUF-gas standard of 1.41% to 1.81% for the 16-year rolling average. • The approval of a 16-year rolling average normalizes the effect of year-to-year weather variation on LAUF gas. The commission established 1.61 percent as the benchmark with a tolerance band of +/- 0.20 percent. The commission assesses a performance penalty if the actual percentage exceeds 1.81 percent. If the percentage goes above 2.11 percent, the commission will conduct a special investigation, which could lead to further commission action. If the actual LAUF percentage is below 1.41 percent, the utility can bank the "reward" to offset any future penalties. (Georgia Public Service Commission, *Determination of Contributing Factors And Cost Allocation for Lost and Unaccounted-for Natural Gas on Atlanta Gas Light Company's Natural Gas Distribution System, Order to Accept the Stipulation Agreed by Atlanta Gas Light Company*, Docket No. 15527-U, September 13, 2002.)
Idaho	• Temporary commission cap on LAUF gas because of abnormal increase in LAUF gas • Periodic utility reporting on improvements in LAUF-gas performance. • The Idaho Public Utilities Commission required a gas utility to improve its performance in the future: "IT IS FURTHER ORDERED that Intermountain Gas be permitted to recover a maximum of 0.85% of its total throughput as lost and unaccounted-for gas. In addition, the Company shall submit to the Commission a quarterly report outlining: (1) the Company's framework for how it has tested for, identified, and remediated equipment measurement errors or leaks; and (2) the business process for alleviating measurement errors through its financial accounting of nominations, scheduling, measurements, flow volume allocation, and billing. Intermountain is directed to work with Commission Staff to outline steps toward identifying the sources of lost and unaccounted-for gas and work toward improvement. The Company's first quarterly report is due no later

<table>
<tr><td></td><td>than 30 days after the calendar quarterly ending December 31, 2008."

(Idaho Public Utilities, In the Matter of the Application of Intermountain Gas Company for Authority to Change Its Prices (2008 Purchased Gas Cost Adjustment, Order No. 30649, Case No. INT-G-08-03, September 30, 2008, 9 at http://www.puc.state.id.us/search/orders/dtsearch.html.)

• It is also instructive to review the following statement in the same order:

"Staff recognized that the percentage of [LAUF] gas is dependent on the complexity of a pipeline distribution system and the flow measurement complexities involved. However, there was some concern as to the increase of 19% over the 2007-2008 PGA, despite Intermountain's historically reasonable loss levels" … Staff also maintained that losses due to errors in faulty meters or measurement control practices should not be recovered in the PGA. In order to evaluate these losses more closely, Staff recommended the Commission order Intermountain to provide a quarterly report outlining the Company's framework for how it has tested for, identified, and remediated equipment measurement errors or leaks… Staff also would like to meet with the Company to outline steps that the Company is taking toward identifying the sources of [LAUF] gas and how these losses may be reduced. Also, because of the significant increase in [LAUF] gas between last year's PGA and this year's PGA, Staff recommended that the Commission place a cap on the amount recovered for [LAUF] gas at 0.85% of throughput, which is the current level proposed for recovery in this case. After the Company has adequately shown its practices to limit the causes of [LAUF] gas and the Company's approach toward reducing it, Staff would then consider recommending removal of the imposed cap (5-7)."</td></tr>
<tr><td>Indiana</td><td>• <u>NIPSCO</u>: Cap at 1.04% with all LAUF-gas costs recovered in the PGA mechanism (rationale is that LAUF gas cost is a variable cost that the utility should recover in the PGA mechanism)
• <u>Vectren</u>: Change in the recovery of LAUF-gas costs from base rates to the PGA mechanism, in addition to capping cost recovery at LAUF-gas percentage of 0.8%.

(Indiana Utility Regulatory Commission, Final Order, Cause No. 43894, November 4, 2010 at http://www.in.gov/iurc/files/Order_in_Cause_No.43894(1).pdf; and Indiana Utility Regulatory Commission, Final Order, Cause No. 43298, February 13, 2008 at https://myweb.in.gov/IURC/eds/Modules/Ecms/Cases/Docketed_Cases/ViewDocument.aspx?DocID=0900b631800e9795.)</td></tr>
<tr><td>Michigan</td><td>• All of LAUF-gas costs recovered in the base rate.
• Utilities recover the costs of company use gas and LAUF gas in base rates, not in the separate PGA charges for purchased gas costs. For gas sales customers, utilities report these costs on a test-year basis and thus include them in base rates. For transportation customers, the utility retains gas-in-kind (GIK) as their contribution toward LAUF gas</td></tr>
<tr><td>New York</td><td>• White paper on LAUF gas.
• Targeted incentive mechanism

(New York State Department of Public Service, Staff White Paper on Lost and Unaccounted for (LAUF) Gas. The white paper noted that each utility makes unique adjustments to their send outs and total disposition.)</td></tr>
</table>

Ohio	• The commission can disallow a portion of the costs if LAUF gas exceeds 5%, pursuant to the Ohio Administrative Code. (Ohio Administrative Code, *Chapter 4901:1-14 Uniform Purchased Gas Adjustment Clause* at http://codes.ohio.gov/oac/4901%3A1-14.)
Oklahoma	• Each utility has a Safe Harbor provision limiting the percentage of LAUF gas recoverable from customers through the PGA mechanism; LAUF gas above the allowed levels triggers a reviews. • Performance Based Tariffs allow the utility to collect a bonus return on equity when the actual LAUF-gas lies below a predetermined percentage; the utility pays a penalty when it exceeds a predetermined cap. (The Oklahoma Corporation Commission's responses to the NRRI survey)
Pennsylvania	• Commission rule on uniform definition of LAUF gas and more stringent LAUF-gas targets over time. • The metrics in the form of targets become increasingly stringent over time, starting at 5 percent and declining to 3 percent by the fifth year. The commission must approve any LAUF-gas above the target for the utility to receive full cost recovery. The commission defines LAUF gas as Gas Received - Gas Delivered - Adjustments, and LAUF-gas percentage as LAUF Gas/(Gas Received) · 100. (Pennsylvania Public Utility Commission, "PUC Finalizes Rulemaking to Establish a Uniform Definition of and Metrics for Unaccounted-For-Gas," *Press Release*, April 4, 2013 at PUC - Press Releases.)
Texas	• 5% cap on LAUF gas with exceptions. • The Texas Railroad's rate handbook states that: Commission substantive rule § 7.5525(b)(1) allows a utility to expense a maximum of 5 percent (5%) of its lost and unaccounted for gas for distribution systems…in a test year. Lost and unaccounted for gas is the difference between the amounts metered in and out of a system…All lost and unaccounted for gas is presumed "lost" unless a utility can provide evidence in a ratemaking proceeding that the unaccounted for gas represented company uses, liquids extraction or meter errors. The Commission may allow greater than 5 percent (5%) lost gas if special circumstances can be shown by the utility. (Railroad Commission of Texas, *Natural Gas Rate Review Handbook*, October 2012, 35 at http://www.rrc.state.tx.us/forms/publications/RateReviewHandbook2012.pdf.)

C. Policy implications

The survey responses show that state commissions differ in (1) the incentive they give utilities to manage their LAUF gas, (2) their ratemaking treatment of LAUF gas, (3) their definition of LAUF gas, (4) their oversight of LAUF gas, (5) their perception of utility performance in managing LAUF gas, and (6) how they evaluate LAUF-gas levels and what criteria they apply. Most commissions have no special incentive mechanisms for LAUF gas.

Utilities generally pass through the LAUF-gas costs as long as the evidence shows that they were not imprudent. In a few states, commissions consider high levels of LAUF gas to be a possible safety threat. Several commissions compare levels of LAUF over different historical periods to determine whether to take any further action.

As part of their obligations to protect customers, state commissions may want to evaluate whether utilities are prudently managing their LAUF gas. Commissions can use different information and approaches in their evaluations.

Although state utility commissions do not assign top priority to LAUF gas, it does affect their decisions in rate cases, PGA filings, and safety matters. LAUF gas is normally an incidental factor in these decisions, but it is significant enough in some states to have received special attention by commission staff and non-utility stakeholders.

The survey responses also show that a chief concern of commissions is utility incentives to manage LAUF gas. One particular worry is a negligent utility tolerating lost gas to the point of jeopardizing safety. Part V looks at options for state commissions to give utilities better incentives. It cautions that while special incentives for utility management of LAUF gas have theoretical appeal, structuring them to elicit better performance is not an easy task. Monitoring and interpreting historical levels of LAUF gas for a single utility, and then taking appropriate action, might offer the best strategy for a commission. Part V discusses the rationale for such a strategy.

V. Regulatory Options to Manage LAUF Gas

A major objective of state utility regulation is to induce high-quality performance from utilities. As a rule, achieving it requires regulators to measure and evaluate utility actions, then inject the evaluation's results into their decisions. Measurement and evaluation can lead to better regulatory incentives and improved utility performance. Improved performance, in turn, can lead to lower utility costs and rates, higher service reliability, and improved safety.

Performance measurement can detect subpar utility management that could spawn further investigation, cost disallowances, or even a change in regulatory incentives.[53] It can also help commissions determine whether utilities are satisfying stated objectives or targets. For example, does a utility's LAUF-gas percentage fall below the targeted 3 percent for any given year? Performance measurement can also give regulators the ability to reward utilities for superior performance that benefits customers. A commission might decide, for example, that a dramatic decline in a utility's LAUF-gas percentage over the past two years deserves a reward (e.g., the utility's earning a higher rate of return).

[53] Commissions might decide that one reason for poor utility performance was the weak or even distorted incentives that they provide utilities. As an example, prompt cost recovery without adequate commission scrutiny could lead to utility indifference in managing costs.

What follows in this section are choices of ways in which commissions can induce utilities to perform acceptably well in managing their LAUF gas. Because utilities have some control over the level of LAUF gas (*see* Part II), and because lowering it has economic, safety, and environmental benefits, commissions should consider ways for utilities to improve their performance. Some stakeholders, notably gas utilities, might disagree with the premise that a utility has some control over the level of LAUF gas. For example, the American Gas Association (AGA) has stated that:

> Most states allow natural gas utilities to track and true-up the costs of lost and unaccounted for (LAUF) natural gas and to recover these costs between rate cases. These costs vary with the gas-commodity costs that utilities pay, with changes in volumes of gas customers consume, and with variations in measured gas volumes into and out of the utilities' gas system. *These fluctuating costs and volumes are outside the control of utilities*[54]...Without a method of adjusting rates in response to fluctuating costs associated with meter uncertainty, [LAUF gas] would have a significant negative impact on utilities.[55] [Emphasis added]

This paper disputes the assertion that utilities have minimal or no control over the level of LAUF gas. The AGA statement also implies that commissions should simply pass through to utility customers LAUF-gas costs with minimal oversight or scrutiny. This paper recommends against such a practice, as it fails to protect customers and hold utilities accountable.

A. Guiding principles on performance measurement and evaluation

1. Two distinct factors

Utility performance derives from two distinct factors: *internal efficiencies and external conditions.* The first factor encompasses management competence in combining and deploying labor, capital, and other resources to manage LAUF gas. The second factor accounts for market, operational, business, and other conditions over which an individual utility has minimal control. As previously shown in Table 1, a utility can take various actions to mitigate the level of LAUF gas.

2. How commissions can apply performance measures

Appropriate use of performance measures—namely, the LAUF-gas percentage in the context of this paper—depends on a commission's ability to separate out the effects of external and internal factors on performance. For LAUF gas, several factors influence its level, some internal to a utility's control, others outside its control. The challenge for commissions is to separate out the effects of these distinct factors. Without this separation, applying performance measures for decision making becomes more difficult and even counterproductive. Specifically, commissions should exercise caution in using performance measures mechanically or as the sole

---

[54] American Gas Association, *Lost and Unaccounted for Gas Cost Recovery Mechanism*, 1.

[55] Ibid., 2.

source of information for evaluating a utility's performance. For example, assume that a commission observes LAUF-gas percentages across utilities and identifies those utilities with the highest levels. Because each utility faces different conditions, the commission should not judge, without further information, those utilities as least competent. It should pay special attention, however, to those utilities exhibiting abnormal or "outlier" performance, which might lead to a more detailed inquiry.[56] In other words, the percentages can act as a guide to future regulatory scrutiny and remedial actions. They function best as a gross metric signaling a potential problem that warrants further inquiry.

3. *Ex post* and *ex ante* performance measures

Commissions can use either *ex post* or *ex ante* measures of performance, or both in a particular situation. They can apply the former measure for prudence reviews or to compare a utility's actual performance with the expected outcome.[57] One prime example of an *ex post* review is the PGA annual reconciliation that includes a "reasonableness" determination. The evaluation of utility performance often links to the concept of "prudence." A common interpretation of prudence is decisions consistent with what a "reasonable person" would do, given the available information at the time of those decisions. The prudence standard focuses on actions, not outcomes.[58] Thus, a performance measure, such as the LAUF-gas percentage, conveys no information on a utility's prudence by itself.

In other applications, commissions can use both kinds of performance measures, with the *ex ante* measure acting as a prospective standard for benchmarking a utility's performance. Assume, for example, that a commission sets a LAUF-gas standard of 3 percent.[59] After observing the utility's actual performance, the commission can compare the 3 percent with the standard to help judge whether the utility was prudent. It could even establish the standard as the cap for cost recovery. If the utility's LAUF gas increases to 4 percent, for example, the commission could require it to absorb the costs of LAUF gas that exceed the three-percent threshold. In another application, a benchmark of three-percent can "red flag" a potential

[56] "Abnormal" implies that the regulator has an idea of what level or range of performance a utility should achieve.

[57] *See*, for example, William E. Encinosa, III and David E. M. Sappington, "Toward a Benchmark for Optimal Prudency Policy," *Journal of Regulatory Economics* 7 (1995): 111-130.

[58] One criticism of the prudence standard is that a utility can satisfy it without performing at an above-average level. It establishes a threshold of minimum acceptable performance; it does not distinguish acceptable performance from exceptional performance. A commission in effect grades and evaluates utility performance dichotomously: The utility's behavior is either acceptable or unacceptable; there are no intermediary levels of utility-management competence.

[59] The three-percentage standard could also determine the level of LAUF-gas costs that the commission would allow in base rates. If the commission permits no change in cost recovery between rate cases, the utility would have to absorb any additional costs. On the plus side, if the utility achieves lower costs, it retains those, at least until the next rate case.

problem when the actual percentage falls short of this expectation. The commission could then conduct a more detailed review to evaluate whether the utility was prudent.

4. Standard for performance

A standard for LAUF-gas performance can take on different meanings. It can represent "average" or "exceptional" performance.[60] In evaluating a utility's performance, the analyst should measure "reference" or "baseline" performance. Average performance can sometimes represent the "mean" performance for a sample of comparable utilities. As already noted, it becomes difficult to interpret differences in LAUF-gas percentages across utilities as a reflection of utility-management competence. Some commissions might interpret average performance as the average historical LAUF-gas percentage over (say) the past five years. Other commissions might view average performance as subpar performance if they deem past performance as unacceptable. They might instead set a more stringent standard for future performance.

Commissions should consider whether they want to define "standard" performance for LAUF gas as a moving target, or as a static concept that remains constant over time. They should expect technology advances and the availability of better management practices to reduce LAUF gas in the future. As measurement techniques become more accurate and utilities replace old meters and pipes, for example, commissions should set more stringent standards over time.

A good regulatory practice is to evaluate a utility's performance by combining quantifiable information and judgment. Performance metrics, such as LAUF-gas percentages, in conjunction with other information can enable commissions to take consequential actions. These actions might include cost-recovery approval, a detailed investigation triggered by preliminary evidence of suspect utility performance, or penalties or rewards for subpar or exceptionally good performance.

In sum, commissions face challenges in interpreting differences in LAUF-gas percentages across utilities or for an individual utility over time. The limitations on isolating the effect of management competence on the differences, even when commissions apply the most sophisticated techniques, are evident.

B. Benchmarking

The generic definition of *benchmarking* is the comparison of an individual utility's performance against some predefined reference (e.g., peer group). This definition focuses on

---

[60] Exceptional performance might include the performance of the first quartile of utilities or, more stringently, those utilities lying on or close to the efficiency frontier measured by statistical or non-statistical approaches. Commissions can designate "standard performance" as a target for a utility to achieve or surpass. The standard itself can reflect the average performance of a sample of utilities or the performance of the leading comparable utilities. Although perhaps appropriate for other operational areas, commissions should not use this standard for LAUF gas, for the reasons given earlier.

outcomes, for instance the services provided by a utility per unit of labor or capital, or the level of gas losses. An alternate definition of benchmarking would center on a utility's practices and uses of different technologies: Has the utility adopted "best practices" in the form of state-of-the-art technologies and management processes? As discussed earlier, utilities have discretion over how they manage LAUF gas. They can, for example, (1) improve the accuracy of their measurement techniques and accounting procedures and their operation and maintenance, (2) replace or repair leaky pipes and auxiliary components, (3) carry out a more aggressive leak-survey strategy, (4) minimize accidental losses through line breaks by aggressively publicizing the dangers of digging before calling 811, and (5) execute systematic meter testing on a random and periodic basis.

Benchmarking normally involves comparing one utility's performance with a peer group of utilities with similar characteristics. But, as discussed earlier, this comparison would be inappropriate for LAUF gas; it is infeasible to control for all the factors that affect LAUF-gas percentages and explain the differences across utilities. The analyst would find it challenging to identify the factors, let alone try to measure their effects. He would find it less cumbersome to control for changes in factors that affect an individual utility from year to year. Even in this instance, he would not find this task easy.

Traditional regulation provides the utility with a weak incentive to prudently manage LAUF gas. The responses to the NRRI survey bear out this sentiment. Benchmarking is a tool that gives commissions a context in quantitative form for better evaluating a utility's performance.

1. Addressing information asymmetry

Benchmarking lessens the information-asymmetry problem inherent in public utility regulation. The commission is at a disadvantage relative to the utility in interpreting and evaluating the utility's performance. Do the actual LAUF-gas levels reflect competent utility management, or do they reflect imprudent management? A utility generally would defend its performance as reflecting its best effort under the circumstances. A utility might tend to provide misleading information about its managerial efforts and opportunities to manage LAUF gas.[61] It may defend a high LAUF-gas percentage, compared with other utilities or its own prior-period percentages, because of unfavorable conditions and other factors outside its control.

Under existing incentives, utilities may act rationally by exerting little effort toward reducing their LAUF gas. A commission might judge those incentives as inadequate for motivating utilities to perform exceptionally or even prudently. Performance indicators for LAUF gas can offer commissions a diagnostic tool to lessen the information asymmetry or handicap they face in their evaluation of utility performance. If commissions had good information about how utilities *should* perform, they could readily set performance standards that utilities would have to meet or suffer financially. In the real world, however, commissions lack

[61] As stated earlier, some utilities might want to give the impression that they have little control over LAUF gas or that, whatever control they might have, they have done their best in managing it.

access to this information. This problem is never more evident than in the case of LAUF gas.

In sum, information asymmetry has two important implications. First, utilities can misrepresent their performance to commissions. Second, commissions need to exercise caution in interpreting performance outcomes. For example, they could wrongly penalize utilities for prudent actions because their LAUF-gas percentages appear excessive. Problematic on the opposite end of the spectrum, utilities could recover all of their LAUF-gas costs even when they acted imprudently. Either of these outcomes is undesirable and can happen when commissions look only at outcomes, to the exclusion of other information that could provide a more accurate picture.

2. Criteria for benchmarking

The major criteria for selecting a utility's area of operation for benchmarking include:

- The effect of a functional area on a utility's total cost or on customer well-being in general;
- The ease of measurement;
- The effort required to interpret a performance measure; and
- The influence of utility management in affecting performance.

Benchmarking LAUF gas would seem to get a mixed review in terms of these four criteria. First, as a percentage of a utility's total costs, LAUF gas is minimal for the vast majority of utilities. Probably of greater significance, if a utility allows its LAUF gas to increase because of negligence in repairing or replacing old pipes, a potential safety threat can arise. Second, while measuring LAUF gas itself is relatively easy,[62] although not without controversy, how commissions should interpret the data is a difficult task. The absolute value of LAUF gas, even expressed as a percentage of sendout, conveys little information. Although comparing it with other utilities or a single utility's performance over similar timeframes is more meaningful, commissions are hard pressed to know whether the utility was prudent or not. They would have to undertake a more detailed inquiry to evaluate the utility's performance. Third, as argued in this paper on several occasions, the utility can influence the level of LAUF gas, making incentives or benchmarking an important factor in affecting outcomes.

3. Summary

Six major points on benchmarking are the following:

1. **A benchmark can establish a point of reference for measuring and judging the performance of an individual utility.**
   Commissions, however, should have additional information before making a decision

[62] The presumption is that stakeholders agree on its definition, which might take some effort.

that would affect the financial condition of a utility. Thus, they should not use benchmarking in a mechanical way or as the sole information in evaluating a utility's performance. To say, for example, that a LAUF-gas percentage below some certain level reflects prudent safety practices by a utility is unconvincing; several factors affect performance and, in this instance, it would be hard to isolate the effect of pipe leaks on LAUF gas.

2. **Benchmarking is generally best applied in "red flagging" potential problems and as a supplemental source of information in determining a utility's performance.** Commissions can ask utilities, "Why has your performance declined over time?" The onus is then on the utility to defend its falling performance.

3. **A lax benchmark for a utility can have a perverse effect (i.e., reducing economic welfare) or produce a zero-sum outcome.**
   If a benchmark is too easy for a utility to achieve, commissions might reward it for simply "average" performance. The result is a windfall gain to the utility at customers' expense. The utility, to put it differently, can increase its profits without achieving real efficiency or performance gains. This outcome would undermine the purpose of a benchmark, which is to improve the performance of a utility so that customers would benefit.

4. **An overly stringent benchmark can unfairly penalize a utility for prudent behavior.**
   A good benchmark needs to walk a fine line between being fair to the utility (i.e., not setting a standard that is unrealistic or out of reasonable reach) and not too easy for the utility to achieve. The baseline that a commission sets for acceptable performance must recognize the environment within which the utility operates and the opportunities for a utility to achieve that level of performance.

5. **Benchmarking quantifies past performance and establishes a baseline for gauging improvements and making comparisons across utilities.**
   For example, commissions can expect parallel improvements in LAUF-gas levels over time because of the dissemination of new technologies (e.g., advanced meters) and accelerated pipeline programs.

6. **The nature of LAUF gas makes it difficult to allow for setting a cap that is compatible with well-accepted industry practices.**
   Definitions vary across utilities, each utility faces unique conditions that affect the level of LAUF gas, and several factors affect the level of LAUF gas—some physical, others nominal, like measurement and accounting error. For these reasons, specifying a single standard for all utilities could easily lead to counterproductive outcomes.

C. Regulatory tools to manage LAUF gas

Commissions observe outcomes, such as the level of LAUF gas, but they do not have adequate knowledge to assess how utility management affected those outcomes. Because they lack the required information to identify a hypothetical optimal performance, commissions must rely on alternative actions, such as special incentives, performance caps, or monitoring utility performance. These second-best approaches readily pertain to LAUF gas.

Commissions might require a management audit of a utility or establish future targets for the utility to meet or else suffer a penalty. In pursuing any action that directly affects a utility's financial condition, commissions should have good evidence that a utility's poor performance actually reflects incompetent or imprudent management. In other words, commissions should know why the utility's performance has fallen before taking any action that affects its financial condition.

Lowering LAUF-gas quantities can improve utility performance by decreasing purchased gas costs, increasing pipeline safety (e.g., from repairing or replacing aging, cast-iron, bare-steel, or old plastic pipes), and reducing environmental harm. This part of the paper centers on three broad tools that commissions can apply to LAUF gas:

1. **Monitoring of utility performance**; for example, the utility reporting to commissions, commissions reviewing the information, and commissions then taking appropriate action;

2. **Setting targets** that when unmet penalize utilities, lead to a detailed inquiry, or require utilities to explain their "subpar" performance; and

3. **Designing and executing an incentive mechanism** that rewards or penalizes utilities.

Before applying these tools, commissions might want to first assess whether a utility's proposed action to improve its LAUF-gas performance is cost-beneficial. They might also want to judge, after the fact, whether the utility's actual LAUF-gas percentage is satisfactory or requires additional review to evaluate management competence. Commissions can establish targets to compare periodically with the utility's actual performance. Performance below the targeted level can result in a penalty for the utility. Commissions might instead prefer an incentive mechanism that would reward the utility for superior performance and penalize it for poor performance. "Superior performance" might be a LAUF-gas percentage below the lower bound of a dead band around a five-year historical average. As an example, assume that the average LAUF-gas percentage for a utility over the past five years is 2.5 percent and the standard deviation is 0.4. If the bounds of the dead band are two standard deviations, the range of "average performance" would be 1.7 to 3.3 percent. If, in the next year, the utility achieves 1.5 percent, the commission might interpret its performance as superior. At the other extreme, the commission can consider any LAUF-gas percentage exceeding 3.3 percent as subpar.

1. Monitoring

The monitoring of LAUF gas would have four purposes: (1) report and evaluate utility performance in controlling LAUF gas; (2) propose changes to regulatory policies and practices to improve utility performance (e.g., establish a target); (3) determine utility compliance with rules, guidelines, and expectations; and (4) recommend any mitigating actions when justified (e.g., pipes replacement, installation of automated meters).

Monitoring is a form of regulatory oversight that commissions would carry out periodically. They could compile information to identify trends in the level of LAUF gas and use that information to identify sources of changes in past levels.

Monitoring can result in commissions' mandating that utilities explain and justify their actions to manage LAUF gas. Especially when utility performance seems suspect, commissions might exercise this discretion. The Texas Railroad Commission has taken such action, as reported in its responses to the NRRI survey:

> If the [LAUF] exceeds 10 percent for the period under review, the inspector will investigate further through review of the most recent purchase and sales figures available. If the inspector believes the operator has not taken proper measures to determine the cause of the high [LAUF gas], an alleged violation is cited. Through the Pipeline Safety Division review of the operator's Plan of Correction, we monitor the operator's progress to resolve the issue and continue to monitor the situation during the next scheduled inspection.

Monitoring can also entail identifying the sources of LAUF gas, including meter errors, pipe leaks, temperature variance, and pressure differences.[63] If a commission determines, for example, that a high LAUF-gas percentage reflects an abnormal level of pipe leaks, it might require the utility to consider correcting this problem. Utility options, for example, can include: (1) timely detection of leaks, (2) timely repair of pipes, (3) continuous monitoring of leaks, and (4) replacement of cast-iron pipes and other pipes with severe leak problems.

2. Target setting

Commissions can establish a LAUF-gas percentage target to compare periodically with the utility's actual performance. They might want to penalize utilities for falling short of pre-specified standards, but not reward them for superior performance. This policy presumes that utilities should not earn a reward even for managing LAUF gas exceptionally well. The penalty can take the form of a negative revenue adjustment, which translates into a benefit for all customers and a cost to utility shareholders.

---

[63] The last two sources occur, for example, when the utility does not correct the volume of sold gas to a temperature of 60°F at a base pressure of 4 ounces.

An acceptable target might be a five-year rolling average with verifiable and reasonably accurate metrics. Another option is for commissions to set targeted reductions in the LAUF percentage over time, such as those recently adopted in rules by the Pennsylvania Public Utility Commission.

Commissions can set either a hard or a soft target. A hard target results in a penalty when the utility fails to meet the predetermined target, without exceptions, no matter the circumstances. As an example, a utility could recover the actual cost of LAUF gas, up to a predetermined LAUF-gas percentage (e.g., 3 percent). One rationale is that any LAUF gas beyond the target poses a serious safety threat or indicates utility imprudence. Setting a target as the threshold for a safe pipeline system or the prudence of a utility, however, conveys a false precision to how commissions should interpret different levels of LAUF gas.

A dubious practice is to hold a utility to a hard standard or target, based, for example, on a peer group of utilities or even on the utility's previous performance. It is presumptuous to conclude that anytime a utility fails to achieve its target, it has acted imprudently. As argued elsewhere in this paper, this policy might be unfair to the utility because an "excessive" LAUF-gas percentage might come from an increase in measurement or accounting error. On the other hand, commissions should assume that utilities have some control over the level of LAUF gas. A perception to the contrary inevitably leads to an open-ended invitation for the utility to pass through all costs to customers with minimal regulatory oversight. Both of these extreme positions make false assumptions that can lead to inefficient and inequitable outcomes.

As a preferred policy, commission approval of a soft target would at least give the utility the opportunity to show why it failed to meet a predetermined target. The LAUF-gas metric functions best as an indicator of a potential problem, but not by itself can it provide commissions with the meaningful information they need to make a well-informed decision or judge a utility's performance.

3. Incentive mechanism

a. Basic elements

A well-structured incentive mechanism would motivate utilities to identify causes of LAUF gas and reduce these volumes when found cost-beneficial. As already noted, several factors can affect LAUF-gas losses. The capability of a utility to control them, as well as the associated costs, helps determine the scope for an incentive mechanism to reduce LAUF gas.

Incentive mechanisms have three basic components: (1) the target or standard (e.g., five-year rolling average); (2) the sizes of the rewards and penalties (e.g., the share of "gains" and "losses" allocated to utility shareholders and customers);[64] and (3) the maximum rewards and

[64] Rewards and penalties should reflect the benefits or costs associated with a specific LAUF-gas percentage that deviates from the "benchmark" level. To the extent quantifiable, they can include safety, economic, and environmental effects.

penalties to the utility. Incentive mechanisms sometimes include a "dead band" (e.g., New York uses two standard deviations from the target level to set the lower and upper bounds). A "dead band" recognizes the inherent uncertainty over identifying a correct benchmark. Incentive mechanisms can also include waivers or exceptions for certain events beyond the control of a utility. Commissions should minimize such exceptions to avoid diluting the incentives underpinning a mechanism.

A poorly structured incentive mechanism can create problems. Specifically, strategic behavior or gaming by a utility can result in a zero-sum outcome or, worse, distortive utility behavior. The former outcome allocates all the benefits to the utility while producing no real gains to its customers. Distortive utility behavior reduces efficiency as the utility over-allocates its resources to reducing LAUF gas, which decreases the overall performance of the utility. An incentive mechanism can also unfairly harm the utility when (1) its design understates the penalties relative to the rewards or (2) the benchmark is set at a value or range of values that makes it overly difficult for the utility to surpass or even achieve them.

Incentive mechanisms focus on outcomes rather than inputs, such as a utility's adoption of the latest technology or "best practice" management tools. The following section illustrates an incentive mechanism for LAUF gas.

b. Example of an incentive mechanism for LAUF gas

Assume that a commission has approved an incentive mechanism for LAUF gas, defined as a percentage of sendout. The mechanism is as follows:

$$\mathbf{laufc_f = laufc_a + s \cdot (laufc_b - laufc_a)}$$

or

$$\mathbf{lauf_a \cdot (1 - s) + lauf_b \cdot s}$$

where $laufc_f$ is the LAUF-gas costs flowed through to customers, $laufc_a$ equals actual LAUF-gas costs incurred by the utility, "s" is the sharing parameter, and $laufc_b$ equals the "benchmark" LAUF-gas cost. A regulator might want to include a "dead band."[65] This provision allows for small deviations of a utility's performance from the benchmark to not affect cost recovery. These deviations may represent "white noise" or randomness of LAUF gas explained by factors beyond a utility's control.

Assume that $laufc_a$ equals \$10 million, $laufc_b$ equals \$12 million, and s is 0.2; $laufc_f$ would then equal \$10.4 million (\$10 million · 0.8 + \$12 million · 0.2). At first glance, the results seem positive: The utility earns \$0.4 million in rewards[66] and customers ostensibly receive benefits of \$1.6 million from lower LAUF-gas costs. (The assumption is that actual

[65] The "dead band" can represent a "benchmark" range of LAUF gas equal to the five-year moving average plus/minus two standard deviations.

[66] The utility earns \$10.4 million of revenues, while its cost was only \$10 million.

costs would equal \$12 million, namely, the "benchmark" costs, in the absence of the incentive mechanism.) Customers pay the actual costs plus the reward to the utility (when $laufc_b > laufc_a$) or the actual costs minus the penalty to the utility (when $laufc_b < laufc_a$).

Customers benefit only when the reduction in actual LAUF-gas costs exceeds the reward to the utility.[67] So for customers to benefit, $laufc_b - laufc_a$ must be greater than $s \cdot (laufc_b - laufc_a)$.[68] Thus, it seems, at least mathematically, that customers always benefit when the utility beats the benchmark, since "s" is less than one. This condition, however, assumes that $laufc_b - laufc_a$ represents the real cost savings from the incentive mechanism. Actual conditions might differ if $laufc_b$, in fact, does not reflect what the utility's costs would have been in the absence of the incentive mechanism.

When considering incentive mechanisms, commissions need to consider the tradeoff between (1) creating strong incentives for superior performance and (2) achieving a balanced distribution of economic gains between the utility and its customers. Cost-sharing mechanisms, like those for LAUF-gas costs, compromise the benefits from stronger incentives for cost reductions by allocating to utility customers a minimum share of the gains from improved utility performance. Under a typical incentive mechanism, a utility receives additional revenues from improved performance. A relevant question in terms of "equity" is: What benefits do customers receive when utility performance improves? Do these benefits at least cover the additional payment from customers to reward the utility? Although in many instances the benefits to customers may be non-quantifiable, commissions should attempt to determine whether the benefits to customers from improved utility performance correspond to the reward that a utility receives. When customer benefits fall short of a utility reward, the utility receives a windfall gain at the expense of customers.

The "benchmark" LAUF-gas cost becomes pivotal for dividing up the gains between the utility and customers. One tough task for commissions is to set the correct benchmark. The wrong benchmark can derive from (1) gamesmanship by utilities and customer groups; for example, the utility might argue that the "benchmark" cost is consistent with a LAUF-gas percentage of 4 percent, rather than with a more correct 3 percent; and (2) incomplete information. The utility generally will argue for a benchmark that will make it easy to earn a reward and avoid a penalty[69]; customer groups, on the other hand, will attempt to make it hard

67 The assumption is that customers' benefits are in the form of lower utility rates. To the extent that a lower level of LAUF gas means a safer distribution system or less methane emitted into the atmosphere, customers and society as a whole would benefit further.

68 The last term represents the portion of the "measured" cost savings that the utility retains.

69 A lenient benchmark makes it possible for the utility to engage in strategic behavior or gaming. The utility would be more likely to increase its profits without achieving any real efficiency gains (i.e., lowering of LAUF gas at a cost less than the benefits). In other words, the mechanism rewards the utility for less than superior performance. The outcome is a distribution of money from customers to utility shareholders.

for the utility to earn a reward. The utility might state its ability to reduce LAUF gas as less than it really is; for example, the utility might argue that it faces severe constraints in reducing LAUF gas when, in fact, it has no such constraints. Commissions will find it difficult to know the "true benchmark." They can ask: What level of LAUF-gas costs would correspond to a prudent utility? What costs would the utility incur in the absence of an incentive mechanism? What are reasonable utility actions deserving of neither a reward nor a penalty?

A good benchmark also should not be susceptible to manipulation by a utility. If the utility, through its actions, is able to affect the "benchmark" value, distortive behavior can result. A utility, for example, might be able to inflate its measurement of past LAUF-gas levels to increase its benchmark costs.[70] The "benchmark" is a dynamic metric that should vary over time in response to changed technological conditions.[71] With improved technologies and measurement techniques, the benchmark for LAUF gas should become more stringent over time.[72]

4. The balancing act

Individuals and groups make trade-offs in making a host of decisions. In understanding the behavior of commissions, trade-offs are also commonplace in their decision making. Specifically, commissions weigh different objectives in their decisions so as to advance the public interest. This balancing means that commissions are willing to "trade" some objectives in return for others. One example of a conflict relating to LAUF gas is a commission trying to maximize utility performance while also keeping utilities financially whole. It could promote the first objective by imposing a hard cap on LAUF-gas costs. Yet, as discussed earlier, if the cap is set too stringently, depriving utilities of prudent-cost recovery, it could unfairly jeopardize the utility's financial condition.

Historically, LAUF gas has exhibited high volatility, making it difficult for commissions to understand the underlying drivers and forecast future values or trends. Commissions may have to resort to a second-best approach in evaluating a utility's performance in managing LAUF gas.

One such approach is to include all the LAUF-gas costs in a PGA mechanism or a separate cost tracker. These costs are difficult to predict and fluctuate widely from year to year.

---

[70] If the benchmark, for example, derives from the average LAUF-gas percentage over the past five years, by inflating past percentages the utility can more easily beat the benchmark and earn a reward or windfall gain.

[71] *See*, for example, Ken Costello and James F. Wilson, *A Hard Look at Incentive Mechanisms for Natural Gas Procurement*, NRRI Report 06-15, November 2006, at http://www.nrri.org/pubs/gas/06-15.pdf.

[72] *See* Pennsylvania Public Utility Commission, "PUC Finalizes Rulemaking to Establish a Uniform Definition of and Metrics for Unaccounted-For-Gas," *Press Release*.

Utilities prefer this approach, and it is easy to see why. An alternative approach is to incorporate all of the LAUF-gas costs into base rates: (1) A commission calculates them for the test year in a formal rate case, and (2) the utility recovers only those costs until it files a new rate case and the commission makes a subsequent decision. No matter how much the actual utility's LAUF-gas costs deviate from their test-year level, the utility recovers only those costs previously approved by the commission in the last rate case.[73]

One problem with this cost recovery is that when commodity prices increase (which is beyond a utility's control), the utility's margin could materially fall, even if the utility prudently managed its LAUF gas. On the plus side, it provides a stronger utility incentive for managing LAUF gas than including all the costs in a PGA-type tracker.

A third approach could achieve a more *balanced outcome* by avoiding the problems with the above two approaches. It would include all costs in a PGA mechanism but establish a cap on cost recovery from customers.[74] As an example, the commission could set a target for LAUF gas at 3 percent, allowing the utility to recover all of its LAUF costs up to this percentage. In line with our previous discussion, the utility would first have an opportunity to explain why it failed to achieve this target before the commission decides on cost recovery. The utility would have a strong incentive to control LAUF gas to 3 percent,[75] but, at the same time, it could recover any increase in gas commodity costs. The latter feature recognizes that the utility has virtually no control over the price it pays for wholesale gas.[76]

D. A proposed multi-step regulatory procedure

Figure 2 illustrates a general approach for regulators to review a utility's performance in a specific functional area like LAUF gas and then take appropriate action.[77] The major steps are benchmarking, monitoring, and decision making on cost recovery, and determining whether to investigate further or implement additional incentives (e.g., establishing a cost-sharing mechanism, cap, target, or standard). The diagram shows four major elements to this approach.

[73] An exception is when a commission allows for interim rate relief under highly abnormal conditions that threaten a utility's financial condition.

[74] As discussed in Part IV, some utilities have such mechanisms.

[75] The simple reason is that the utility would suffer a loss in cash flows, as it could not pass through all of its costs to customers.

[76] Although the utility could negotiate prices when signing a contract, it generally pays a price set by market conditions over which it, as a single buyer, has no influence.

[77] The following discussion follows the general approach outlined in Ken Costello, *How Performance Measures Can Improve Regulation*, NRRI 10-09, June 2010 at http://www.nrri.org/documents/317330/a8f18562-f40e-4276-8848-8b904bdbf41f.

1. Recognition of regulatory influence on utility performance

Regulation itself affects utility management behavior. Together with factors that fall outside the control of a utility, management behavior determines a utility's performance. Regulatory rules, policies, and practices directly and indirectly affect utility performance. Utility performance, in turn, can influence regulatory actions. A high LAUF-gas percentage, for example, might induce commissions to provide utilities with stronger incentives or to set standards for future performance. As noted earlier, such actions require careful thought to avoid distorted outcomes.

2. Cursory performance assessment

Commissions should initially assess the utility's performance by comparing actual performance with a pre-specified standard. The standard can correspond to prudent or expected utility performance. Any substantial deviation can reflect exceptionally good or bad performance. Admittedly, the discrepancy is a crude measure that by itself does not infer anything about the competence of utility management. Utilities should have the opportunity to respond to any evidence that at first glance suggests bad performance, with subsequent evaluation by the commission.

The challenge with LAUF gas, as repeated a few times in this paper, is to establish a reasonable standard for individual utilities. Because of unique conditions, standards should differ across utilities and depend largely on a utility's past performance. The problem with this standard is that it might reflect historically subpar performance by the utility, so commissions might continue to approve a utility's performance even though the utility could do better under a more reasonable set of conditions.

3. Post-review action

Based on its review, a commission can take various actions. They can include (a) allowed cost recovery by the utility; (b) a more detailed investigation, such as an audit;[78] (c) setting of a cap or standard for future periods; or (d) establishment of an explicit incentive mechanism that would reward or penalize the utility for exceptional performance.

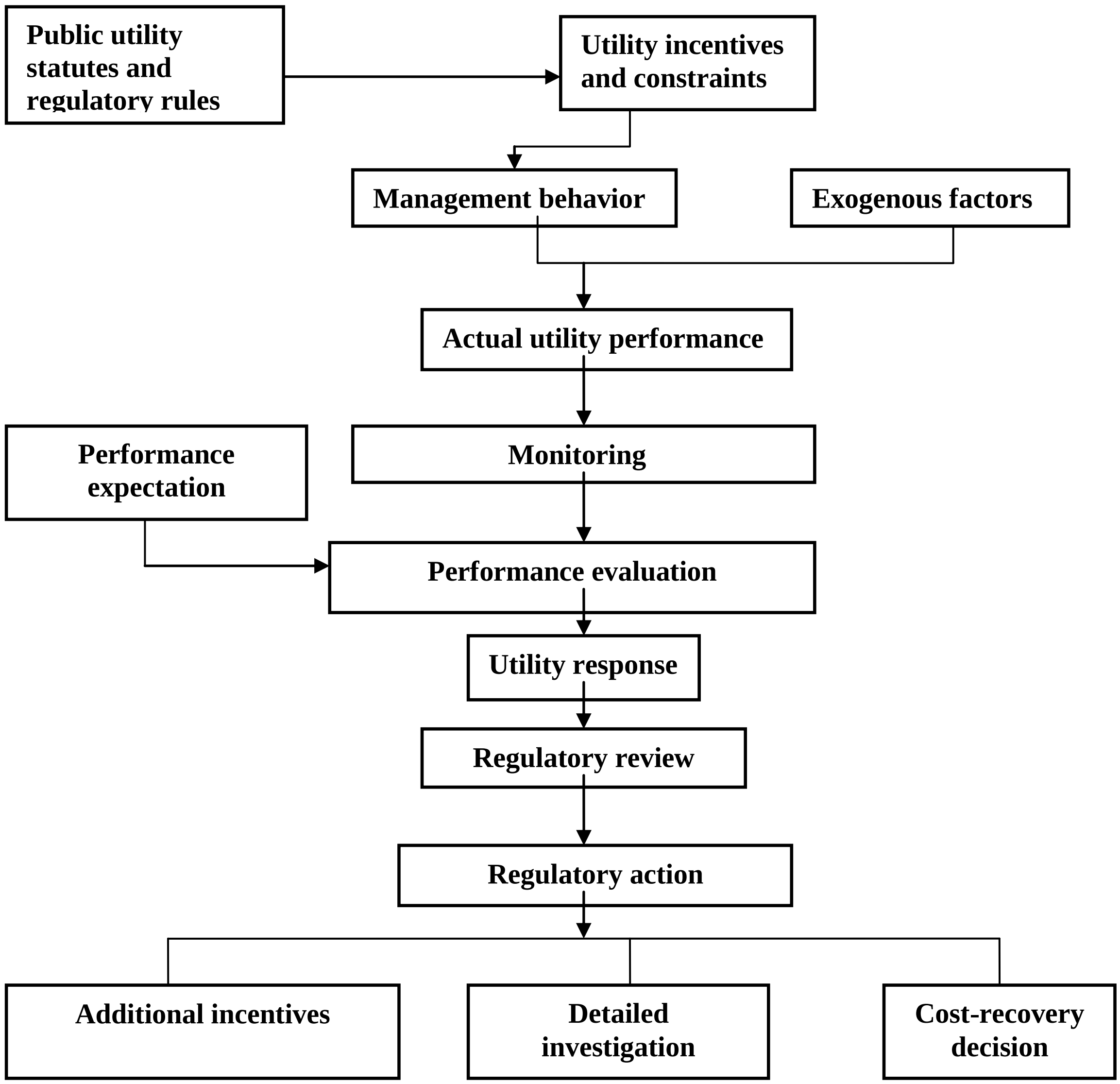
4. The end result of accountable regulation

Performance evaluation can help commissions determine "just and reasonable rates" and make utilities accountable for subpar performance. Accountability requires regulatory assurance that utility costs incorporated into rates reflect prudent actions. Accountability also demands that commissions recognize the financial interests of utilities; namely, to permit a prudent utility a reasonable opportunity to earn a rate of return that attracts capital to serve the long-term interest

[78] The commission can also order the utility to report on any unexplained increase in LAUF gas. The responsibility would then lie with the utility to justify the increase, rather than place the burden on the commission staff or other parties to explain the increase.

of their customers. A systematic monitoring of LAUF gas can assist commissions in attaining those outcomes.

Figure 2: Regulatory Benchmarking, Monitoring and Action



VI. Recommendations for State Utility Commissions

At first sight, a reduction in LAUF gas would seem to lead to a desirable outcome. Yet, like almost everything else, it involves costs. So any assessment of a utility's performance hinges on a cost–benefit assessment of how much customers should pay to lower their utility's LAUF gas: What would be the purchased-gas cost savings? What would be the safety benefits from fewer leaks? What are the positive environmental effects? For fixed dollars spent on reducing LAUF gas, one rule is for the utility to direct those dollars to activities that maximize LAUF-gas reductions.

This paper makes the following recommendations:

1. **It would seem inappropriate to compare LAUF percentages across utilities at a given point in time for determining cost recovery and utility prudence.** LAUF percentages depend on the singular conditions of each utility. They include weather, metering and measurement technologies, the age of the pipes, and customer composition. When taking a snapshot of LAUF percentages across utilities, one notices large differences, even within the same state. Although utilities have some control over how these conditions affect the volume of their LAUF gas, it would be difficult to quantify their individual effects. Thus, while a cross-sectional comparison of LAUF-gas percentages may loosely reflect relative utility effectiveness, it is not precise enough to evaluate management competence. Commissions would need additional information to make this determination.

2. **The best benchmark might come from tracking a single utility's LAUF percentage over time.** Commissions might want to consider the rolling-average LAUF percentage for a utility over a specified historical period as a benchmark. Historical performance might reveal an upward or downward trend that commissions can use for setting a future benchmark. Trends might reflect a change in utility effectiveness in managing LAUF gas. Any benchmark should be fair and reasonable for both the utility and its customers. Because several factors affect LAUF gas, and because they vary across utilities, inter-utility comparisons are difficult to interpret (*see* the previous recommendation). It would seem ill-advised, then, to judge a utility's performance on this comparison. Because of the erratic and "black box" nature of LAUF gas, it also seems unfair to establish a hard target that unconditionally penalizes a utility for not meeting it. Instead, commissions should consider it more fair and appropriate to use the target as a threshold for triggering further review. The commission itself might compile information for the review or require the utility to provide evidence for why its performance fell below a specified target.

   One caveat with using a single utility's past performance as a benchmark is that historical outcomes might represent less-than-prudent performance. A utility with a stable or even a falling LAUF-gas percentage might still exhibit imprudence, given that its starting-period percentage is excessively high (e.g., 9 percent). Another utility with a low initial percentage, reflecting superior performance, will find it more difficult to improve its performance over time. The latter utility may receive a harsher review from the commission even though it has performed admirably over time. The first utility, in contrast, might invite little scrutiny, or even praise, from its commission, even though it lies farther below the "frontier curve" of optimal performance. Such a regulatory response might violate "fairness" standards by penalizing those utilities that initially made a more concerted effort to manage their LAUF gas.

3. **Utilities can influence LAUF-gas levels in different ways.**
   Different causes account for the level of LAUF gas, including measurement error, accounting error, stolen gas, pipe leaks, third party damages, line pack and consumption on an inactive meter. Some of these are within a utility's control. The general impression conveyed by utilities is that they have minimal influence on the level of LAUF gas. To the contrary, state commissions should presume that utilities do have some control and consider monitoring LAUF gas to identify any serious problems. Since utilities in various ways can influence the level of LAUF gas, with economic, safety and environmental consequences, commissions might want to explore options for improving utility performance.

4. **Commissions may want to be proactive in assessing LAUF performance of utilities, especially in making sure that utilities take all prudent actions to mitigate LAUF gas.**
   Utilities tend to give the impression that LAUF gas is mainly beyond their control; so, from their perspective, the commission should merely pass through the costs with minimal scrutiny (e.g., rubber-stamping the costs). A more realistic view is that utilities can influence LAUF-gas levels, which is a major point made in this paper. The real policy question, then, is whether actions to reduce LAUF-gas levels are cost-beneficial: Do they lower purchased gas costs, achieve higher pipeline safety and produce other benefits that justify the costs?

5. **Commissions may want to acquire better information from utilities on the sources of LAUF gas.**
   To better interpret LAUF-gas levels and their variability over time requires knowing, for example, whether pipe leaks are more important than measurement and accounting errors. Evaluating utility performance and taking appropriate action require that commissions have access to a quantitative breakdown of the sources of LAUF gas. The commission can then judge whether a utility should take additional action and what specific actions they should take to reduce LAUF gas. Admittedly, it is not always easy to quantify the sources of LAUF gas. Because most commissions currently do not require this information from utilities, it is unknown how much effort a utility would have to make to compile it.

6. **Commissions may want to exercise caution in designing and applying an incentive mechanism for LAUF gas.**
   A particular challenge is specifying a benchmark that reflects the expected performance of a prudent utility. An incentive mechanism might include a "dead band" that accounts for the random and uncertain nature of LAUF gas.[79] These features make it difficult for commissions to structure a mechanism that is fair to both utility shareholders and customers. Few commissions have explicit incentive mechanisms to manage LAUF gas, perhaps partially for this reason.

7. **Commissions' most effective tool might be monitoring and assessing utilities' LAUF-gas levels.**
   This paper presents a multi-step monitoring procedure by which regulators can review a utility's performance in managing LAUF gas and then take appropriate action. The major activities are benchmarking, monitoring, and decision making on cost recovery, whether to investigate further, or whether to provide additional incentives for managing LAUF gas (e.g., establishing a cost-sharing mechanism, cap, target, or standard). The monitoring procedure contains four major elements: (a) recognition of regulatory influence on utility performance, (b) cursory performance assessment, (c) post-review action, and (d) the end result of accountable regulation. This approach, for example, places the burden on the utility to report and explain any abnormal increase in LAUF gas.

[79] To the extent that a utility is able to measure with reasonable accuracy the effects of different factors on the level of LAUF gas, the need for a "dead band" diminishes.

Appendix A: Survey Questions

1. Has your commission addressed the topic of lost and unaccounted-for (LAUF) gas in recent rate cases, PGA proceedings or other venues? If so, could you please cite the docket number?
2. Has your commission written a report or other document on LAUF gas?
3. How does your commission treat LAUF gas for ratemaking?
    a. Does it flow through the PGA?
    b. Is it part of base rates?
4. What incentives does your commission provide utilities to manage LAUF gas?
5. What actions do utilities in your state take to reduce LAUF gas? Are these actions based on a cost-benefit criterion?
6. Does your commission feel that utilities could do a better job of managing their LAUF gas?
7. Has LAUF gas become a topic of concern in recent years triggering a commission investigation or other action?
8. Has your commission investigated the relationship between LAUF gas and pipeline safety? Has your commission, for example, ever relied on historical statistics on LAUF gas to encourage or require a utility to reduce its pipe leaks by more prompt detection or repair?
9. Do all the utilities in your state:
    a. Use the same definition for LAUF gas?
    b. Treat LAUF gas the same for ratemaking?
10. Do utilities in your states quantify LAUF gas by source? These sources can include measurement error, pipe leaks, stolen gas, accounting error.
    a. For example, do they calculate the LAUF gas caused by pipe leaks?
    b. Are any of these calculations publicly reported?
11. Does your commission require utilities to report periodically the amount of their LAUF gas?
12. Are there public statistics on LAUF-gas percentages by utility over an historical time frame?
13. Does your commission have estimates of the increase in purchased gas costs attributable to LAUF gas?
14. Does your commission monitor LAUF gas over time? If so, how does it use the information?

Appendix B: State-by-State Survey Responses

State	1. Has your commission addressed the topic of lost and unaccounted-for (LAUF) gas in recent rate cases, PGA proceedings or other venues?
Alabama	No
Alaska	LAUF gas was discussed at the hearing in Docket U-08-142. The Commission was trying to gain a better understanding how the utility calculates LAUF gas. It was discussed for informational purposes only.
Arizona	No, this issue was addressed with a number of gas utilities in the 1990s, but hasn't come up in recent years.
Arkansas	Yes, in Docket No. 09-096-TF, LAUF was a related issue, concerning cost allocation across jurisdictions, in this filing by Arkansas Oklahoma Gas Corp. to revise its Purchased Gas Adjustment clause (PGA).
Colorado	No
Connecticut	Yes, the Authority addressed it in the company's rate case (e.g., Docket Nos. 08-12-06 Application of Connecticut Natural Gas Corporation for a Rate Increase, 08-12-07 Application of The Southern Connecticut Gas Company for a Rate Increase and 10-12-02 Application of Yankee Gas Services Company for Amended Rate Schedules).
Delaware	This topic is addressed in the annual Gas Cost Rate ("GCR") filing of Delmarva Power & Light Company and the Gas Sales Rate ("GSR") filing of Chesapeake Utilities Corporation - Delaware Division; presently these issues are under review in PSC Docket No. 12-419F (Delmarva Power & Light Company) and PSC Docket No. 12-450F (Chesapeake Utilities Corporation – Delaware Division).
Florida	No, LAUF gas has not been an issue in recent rate cases or PGA proceedings.

Georgia	AGL: Yes, in Docket No. 15527 (September 13, 2002)—Determination of Contributing Factors and Cost Allocation for Lost and Unaccounted-for Natural Gas of Atlanta Gas Light Company's Distribution System. This establishes minimum performance standards for LAUF gas of 1.41% to 1.81% for the rolling 16-year average, as reported to PHMSA. Atmos: Yes, in Docket No. 22874 (January 8, 2007)
Idaho	The Commission regularly reviews LAUF gas in PGA proceedings. If significant increases in LAUF gas are identified, the Commission may take action. As an example, in Case No. INT-G-08-03 (Order No. 30649), the Commission ruled that Intermountain Gas only be allowed to recover a maximum of 0.85% of its total throughput as LAUF gas. In addition, the Commission ordered the Company to submit biannual reports (previously, the utility had to submit quarterly reports but this requirement changed when its performance improved) outlining: (1) the Company's framework for how it has tested for, identified, and remediated equipment measurement errors or leaks; and (2) the business process for alleviating measurement errors through its financial accounting of nominations, scheduling, measurements, flow volume allocation, and billing. Intermountain Gas was directed to work with the Staff to outline steps toward identifying the sources of LAUF gas and work toward improvement. The Company is still limited to recovering a maximum of 0.85% of its total throughput as LAUF gas, and continues to file reports on a semi-annual basis.
Indiana	The Commission typically determines actual LAUF gas percentage within the confines of a rate case. Utilities recover their LAUF gas percentage through the gas cost adjustment (GCA) process, which is equivalent to the PGA.
Iowa	It is in the PGA rules; specifically, it is Iowa Administrative Code 199-19.10(1)b.
Kansas	Not recently and not explicitly in rate cases; the last time that the Commission addressed the LAUF gas question generically was in Docket 106,850-U in 1988. In this Docket the Commission set the limit of LAUF gas that can be flowed through the PGA to 4%. This LAUF requirement is still in effect.
Kentucky	LAUF is addressed in PGA applications for cost recovery issues; there is no specific docket number because LAUF treatment for cost recovery is long-standing and consistent except for unique circumstances; the Quarterly Report of Gas Cost Recovery Rate Calculation Word is used by most small LDCs in Kentucky in filing their quarterly PGAs; schedules II and IV contain calculations which limit LAUF recovery to 5 percent.
Louisiana	Yes, in PGA Docket No. U-22407 dated March 24, 1999
Maryland	The issue of LAUF was last reviewed in a Baltimore Gas and Electric Company base rate proceeding (Case No. 9230). In that proceeding, the Company proposed a revision to how LAUF would be calculated. The Commission accepted the Company's proposal.

Massachusetts	No
Michigan	No
Minnesota	Yes, in the following PGA proceedings: Docket No. E,G-999/AA-07-1130; Docket No. E,G-999/AA-09-896; Docket No. G-999/AA-10-885; and Docket No. G-999/AA-12-756.
Mississippi	LAUF is addressed on a case-by-case basis, the most recent being the City of Moss Point in Docket 2011-UA-337. Originally a Sale and Transfer docket, the topic of LAUF gas became a major issue during the Pipeline Safety Division's investigation.
Missouri	The Commission regulates cost recovery for several natural gas utilities, including NorthWestern Energy (NWE), Montana-Dakota Utilities (MDU), Energy West Montana (EWM), and Cut Bank Gas (CBG). Only NWE has regulated transmission service; the others are distribution utilities only. LAUF gas costs are typically recovered as a part of procured gas costs that are tracked and trued-up on a regular basis, rather than as a part of fixed delivery costs recovered in general rate cases. CBG does not have an established LAUF rate. For the others, the established LAUF rates are as follows: NWE (2.46%), MDU (0.72%), and EWM (1.12%). The LAUF rates are designed to include gas used in system operations. The NWE rate includes LAUF gas loss rates on the transmission system as well as the distribution system. The MDU and EWM rates are distribution system only rates. Utilities are also allowed recovery of losses on transported gas using the LAUF rates in effect for the transport system. The NWE LAUF rate of 2.46% is also referred to as a "fuel reimbursement percentage." The NWE fuel reimbursement rate for gas injected into storage is 1.14%. The MDU rate of 0.72% was established in Docket No. D2002.5.59, representing losses incurred in the year ending June 30, 2001. The EWM rate was established as a three-year average in Docket No. 85.7.26, Order 5153a, and is now fixed at 1.12%. In Docket No. D2011.4.32, Final Order No.7150b, the Commission allowed cost recovery of gas losses equaling 15% of total purchases on the CBG system. Cost recovery was allowed under the condition that CBG would act immediately to replace the affected pipe.
Nebraska	No
Nevada	In Southwest Gas Company's ("SWG") annual rate adjustment application (Nevada version of the PGA), the Commission establishes a shrinkage rate to recover a share of the LAUF gas from transportation customers who procure their gas from a third-party supplier. The most recent annual rate adjustment application was Docket No. 12-06013.
New Hampshire	No

New Jersey	The Companies include LAUF in their Basic Gas Supply Service (BGSS) filings every year and Staff reviews those submittals. There have been no formal proceedings involving LAUF in many years.
New Mexico	Notably in Case 2811 in 1998; also cases 2587, 2760 and 2762 have mentions of LAUF gas.
North Carolina	LAUF is set in rate cases. LAUF is also reviewed in annual reviews of LAUF gas.
North Dakota	No
Ohio	PGA audits of small LDCs review LAUF along with management and performance audits of large LDCs. The last case filed with the Commission was Duke's 2012 M/P audit in case number 12-218-GA-GCR.
Oklahoma	Yes, in several dockets.
Pennsylvania	LAUF is primarily addressed in Purchase Gas Cost (PGC) or Gas Cost Recovery (GCR) mechanisms within Pennsylvania but could also be considered in rate cases, orders, etc. However, each PGC or GCR company would be separately docketed. In addition, the Commission has issued a Proposed Rulemaking Order, *Establishing a Uniform Definition and Metrics for Unaccounted-For-Gas*, at its June 7, 2012 Public Meeting at Docket No. L-2012-2294746 (note: The Commission has since approved the rule).
South Carolina	Docket No. 2009-435-G - Order No. 2010-250 (Piedmont)
South Dakota	No
Tennessee	No
Texas	The Railroad Commission addresses either directly or indirectly the issue of LAUF gas in virtually all gas distribution rate orders. Rate cases for the larger distribution utilities will generally only address the cost of service rates, exclusive of gas costs which have their own separate rider-type provision. Those PGA (GCA, etc.) provisions will address LAUF and its limitations, typically the lowest of actual LAUF or 5%. A recent example with PGA (GCA) inclusions in the Final Order is Docket No. 10170 (Atmos Energy, Mid-Tex Division).

Utah	Docket 08-057-02: *In the Matter of the Revision of Questar Gas Company's Integrated Resource Planning Standards and Guidelines* at http://www.psc.utah.gov/utilities/gas/gasindx/0805702indx.html. The Commission's March 31, 2009, Order in this docket requires reporting on "The current level of lost and unaccounted for gas and an explanation of the Company's efforts at reducing lost and unaccounted for gas and reducing natural gas emissions in pipeline construction and operations activities." (*See* Page 30), at http://www.psc.utah.gov/utilities/gas/gasindx/documents/0805702ROosagfqgc.pdf. Docket No. 09-057-16: *In the Matter of the Application of Questar Gas Company for Authority to Increase its Retail Gas Utility Service Rates in Utah and for Approval of Its Proposed Gas Service Schedules and Gas Service Regulations*.
Vermont	No
Virginia	No
Washington	Yes, in Docket UG-060256, Order 05, paragraph 49
Wisconsin	The Commission addresses LAUF gas in every rate case proceeding during its review of expenses for reasonableness. However, the allowance of LAUF has not been a contentious issue in any recent rate proceeding.
Wyoming	LAUF gas has been addressed in rate cases, pass-on filings, and as separate filings in the past. Natural gas utilities document their LAUF gas in tariffs, and the calculation is most typically changed in Rate Cases. The most recent rate case example is Questar Gas, Docket 30010-113-GR-11 (Record 13023). The most recent example of an adjustment outside of a rate case is SourceGas, Docket 30022-187-GA-12 (Record 13109). SourceGas' LAUF gas was previously established in their rate case, Docket 30022-148-GR-10 (Record 12450).

State	**2. Has your commission written a report or other document on LAUF gas?**
Alabama	No
Alaska	No

Arizona	No
Arkansas	No
Colorado	No
Connecticut	Only when LAUF gas is found to be an issue would it be addressed in the company's rate case
Delaware	No
Florida	No
Georgia	No
Idaho	No
Indiana	No
Iowa	No
Kansas	The November 28, 1988 Order in Docket 106,850-U discussed in *Question 1* above
Kentucky	No
Louisiana	No
Maryland	No
Massachusetts	No
Michigan	No

Minnesota	No, the Commission generally relies on the summary and comparison of each regulated natural gas utility's LAUF-gas percentage in the Minnesota Department of Commerce's annual review of gas costs.
Mississippi	No
Montana	No
Nebraska	No
Nevada	In Docket No. 08-05010, SWG filed a report on May 15, 2008 pursuant to a Commission Order entitled, *Lost and Unaccounted for Gas Contributors*. This report was the subject of Docket No. 08-03033 – an investigatory docket – on the calculation of the shrinkage rate in the Southern Nevada Division of SWG. On March 2, 2009, the Commission issued an Order in Docket No. 08-03033 with its findings that the shrinkage rate in the Southern Nevada Division of SWG should have a separate high-pressure and low-pressure rate for transportation customers. Transportation customers served directly off high-pressure lines only pay the high-pressure shrinkage rate and all other transportation customers pay both the high and low-pressure shrinkage rate. The high-pressure and low-pressure shrinkage rates are calculated based on the ratio of the miles of high-pressure pipe and low-pressure pipe to the total miles of pipe in the distribution system.
New Hampshire	No
New Jersey	No
New Mexico	No
North Carolina	No; It should be noted that because North Carolina did not get interstate service until 1951, our distribution system is generally newer than the systems in some states. Also, over a period of decades, gas pipeline operators in North Carolina, working with the Commission's Pipeline Safety Section, have eliminated cast iron and bare steel mains in our State (some of which were inherited with old manufactured gas systems). As shown in PHMSA's inventory of cast iron pipe, some states have a very significant amount of old pipes that tend to be a source of leaked gas. If the Commission has not written a report on LAUF gas, it is because it isn't the issue here that it is in some states.
North Dakota	No
Ohio	No, the Commission does not have reports other than those in the audit reports.

Oklahoma	Yes, each gas distribution utility must report annually its actual LAUF gas.
Pennsylvania	Commission Staff released a report with the Proposed Rulemaking Order at Docket No. L-2012-2294746 entitled *Unaccounted-for-Gas in the Commonwealth of Pennsylvania* (Joint Report).
South Carolina	No
South Dakota	No
Tennessee	No
Texas	Through the utility's Plan of Correction documents, the Safety Division monitors the utility's progress to resolve the LAUF gas issues and continues to monitor the situation during the next scheduled inspection.
Utah	No
Vermont	No
Virginia	No
Washington	No
Wisconsin	No
Wyoming	No, the standards and levels of LAUF gas are compared with nationwide industry averages and comparable Wyoming utilities to determine reasonableness; also, a utility's historical reported LAUF is used to discern any changes. In cases where variability or levels seem suspect, the Commission has inquired of the utilities to investigate and report.

State	3. How does your commission treat LAUF gas for ratemaking? a. Does it flow through the PGA? b. Is it part of base rates?
Alabama	Flows through the PGA
Alaska	Flows through the PGA
Arizona	Flows through the PGA
Arkansas	Flows through the PGA
Colorado	Flows mostly through the PGA and minimally through base rates
Connecticut	Flows through the PGA
Delaware	Flows through the PGA
Florida	For companies that are not totally unbundled, LAUF-gas costs flow through the PGA With respect to transportation customers, LDCs retain a small percentage of gas received by the customer to cover LAUF gas; this amount is specified in the tariff and varies by LDC; the amount of gas retained is credited to the PGA and reduces the quantity of gas the LDC is required to purchase for its system supply. For utilities that are no longer in the merchant function, LAUF gas is part of the overall imbalances and allocated among the third party marketers.
Georgia	AGL: No, *see* Docket No. 15527. Interruptible customers are allocated 0.8% of their annual gas volumes. Marketers are allocated the remainder through a true-up process. These costs are passed on to the firm customers. Atmos: Flows flow through the PGA
Idaho	(a) Yes; (b) Intermountain Gas has a normalized unit cost amount of LAUF gas they are allowed to collect through base rates. During each PGA, the base rate revenue recovered by the Company for LAUF gas is determined by applying the unit cost amount to estimated sales, and then adjusting for the

	rate of recovery approved from the prior PGA. The Company reconciles the difference between what was collected from the previous year's forecasts and actual LAUF gas during each PGA hearing. Avista collects all of its LAUF-gas cost through the PGA and then reconciles the difference between the previous year's forecasts and actual LAUF gas during each PGA.
Indiana	The Commission establishes an LAUF percentage as part of a rate case, but the LAUF gas flows through the PGA process.
Iowa	Flows through the PGA
Kansas	Flows through the PGA, up to a LAUF-gas percentage of 4%; also, included in base rates
Kentucky	Flows through the PGA
Louisiana	Flows through the PGA for sales customers Not recoverable for transportation and non-jurisdictional sales service
Maryland	Generally, it is handled in base rates, with any adjustments for the commodity costs made in the annual PGA proceedings. However, gas costs for sales service customers are addressed in the annual PGA proceedings.
Massachusetts	Flow through the PGA.
Michigan	The utility subtracts LAUF gas from our annual PGA cases and not recovered through the PGA; it is part of base rates.
Minnesota	Flows through the PGA
Mississippi	Flows through the PGA
Montana	Typically flows through the PGA
Nebraska	Flows through the PGA

Nevada	Flows through the PGA; all sales (bundled) customers in Nevada pay for LAUF-gas costs through the purchased gas costs contained in the quarterly gas cost filings. In Southwest's service territories, transportation customers pay a shrinkage rate calculated in the annual rate adjustment application for their share of LAUF gas costs. The revenues from the shrinkage rate are credited to the 191 Account. In Sierra Pacific Power Company's ("SPPC") service territory, transportation customers provide in-kind gas for their share of LAUF gas pursuant to SPPC's tariff, Schedule Nos. TF & TI §5.2.
New Hampshire	Flows through the PGA
New Jersey	Flows through the PGA
New Mexico	Flows through the PGA
North Carolina	Part of both base rates and PGA flow through
North Dakota	Part of both base rates and PGA flow through
Ohio	Flows through the PGA
Oklahoma	Flows through the PGA
Pennsylvania	LAUF is handled in PGC or GCR proceedings relating to gas cost rates. The PGC or GCR mechanisms are not part of base rate cases. However, LAUF's drivers or remedies could be a factor in base rates and therefore, could be a focal point of base rates.
South Carolina	Flows through the PGA for both Piedmont Natural Gas Company and South Carolina Electric & Gas Company
South Dakota	In some cases flows through the PGA; in others part of base rates
Tennessee	Flows through the PGA

Texas	Flows through the PGA, with limitations. The Commission generally limits LAUF gas to actual, not to exceed 5% (computed annually). Generally speaking any gas cost expense associated with LAUF gas in excess of 5% must be absorbed by the utility and not passed on to the customers. For many years now the practice has been for gas costs to stand alone, found in the PGA (GCA) provisions, and this is where you will find the rate treatment for LAUF gas. The base rates cover the entire range of the utilities revenue requirements, exclusive of gas cost. So, the short answer is no.
Utah	Flows through the PGA
Vermont	(a) Yes; (b) Yes, it's included with the gas costs.
Virginia	Flows through the PGA.
Washington	Flows through the PGA.
Wisconsin	The Commission may treat LAUF differently for any given utility but, in general, a reasonable amount is considered an allowable expense; LAUF gas costs are part of both base rates and the PGA.
Wyoming	Flows through the PGA: The utilities report fuel purchased at the supply meters, and flow the cost to actual metered sales. The difference, or LAUF gas, is reviewed for historical and industry reasonableness. There are cases (SourceGas, ChoiceGas Program, for example), however, where the LAUF gas is included in the SourceGas Distribution Cost to the competitive suppliers and is included within the procedure by tariff for assessing the fees. *See* Docket 30022-187-GA-12 (Record 13109) for example of this reported LAUF level.

State	**4. What incentives does your commission provide utilities to manage LAUF gas?**
Alabama	None
Alaska	None
Arizona	None

Arkansas	In some instances, the Commission has capped the LAUF-gas percentage as an incentive for utilities to repair natural gas leaks; also, the Commission has approved a program which supports the expedited replacement of pipeline infrastructure.
Colorado	None
Connecticut	None
Delaware	For Chesapeake Utilities Corporation there is presently an *Unaccounted For Gas Incentive Mechanism* outlined in the Company's tariff; this mechanism was approved to continue beyond an initial three-year test period in the early 1990s by Order No. 4189 in PSC Docket No. 95-206F.
Florida	None
Georgia	AGL: LAUF-gas percentage must meet the minimum performance standards, otherwise AGL will be held to the penalty structure established in DN 15527. Atmos: None
Idaho	The Commission does not have specific incentives for managing LAUF gas.
Indiana	The Commission attempts to establish a reasonable LAUF-gas percentage in each rate case; since the utility will not recover any costs above the established percentage, the utilities' incentive is to keep the LAUF-gas percentage at or below the Commission's established percentage; it is their responsibility to manage the LAUF-gas percentage granted in its last rate case.
Iowa	Unknown
Kansas	Penalty mechanism in the PGA if LAUF gas exceeds 4%
Kentucky	From a cost recovery aspect, the Commission's long-time practice has been to limit LAUF gas recovered through gas cost in PGA rate changes to five percent; the intent is to encourage timely leak detection and pipeline repair, addressing both cost and safety concerns.
Louisiana	Under no circumstances may LAUF gas recoverable from sales customers exceed 6% of purchase volumes on an annual basis

Maryland	There is no specific Commission incentive to manage LAUF gas. However, as a matter of course, if there is a significant change in LAUF gas on a year-to-year basis that is noted in a gas utility company's annual PGA/PGC proceeding, the issue is addressed at that time.
Massachusetts	The Commission has approved proposals by utilities to recover on an annual basis (rather than wait for the next rate case filing) the costs associated with the replacement of non-cathodically protected steel mains and services as well as cast-iron and wrought-iron mains. *See* Bay State Gas Company, d/b/a Columbia Gas of Massachusetts, D.P.U. 12-25 (10/31/2012).
Michigan	The fact that LAUF-gas cost recovery is set in a rate case and does not vary from year to year is supposed to incent utilities to keep losses under control; but now utilities are filing rate cases almost every year due to new laws passed in Michigan.
Minnesota	None
Mississippi	None
Montana	Cost recovery for "reasonable" loss is straightforward: Cost recovery for loss in excess of the reasonable level may be contested and disallowed; in a contested case the "reasonable" level would be determined according to historical loss, utility activity in pipeline maintenance and investment, customer benefits, and other relevant variables.
Nebraska	None
Nevada	The Commission does not provide incentives to the utilities to manage LAUF gas given the historically low levels of LAUF gas, i.e. approximately 1% for SWG and 3% for SPPC. (Historical LAUF percentages are provided by utilities and verified by review of PHMSA Reports over time.)
New Hampshire	There are no formal policy decisions spelling out incentives.
New Jersey	No direct incentives *per se*
New Mexico	Not aware of any incentives
North Carolina	The Commission oversees LAUF gas in the annual reviews of gas costs, and the Company is asked to investigate LAUF gas if it is too high by either Public Staff requests or Commission Order.

North Dakota	None
Ohio	The Commission can disallow purchase gas cost recovery of LAUF above 5 percent.
Oklahoma	Each company's tariff has a Safe Harbor provision which limits the percentage of LAUF it may recover from ratepayers through the PGA. LAUF gas above the allowed levels triggers reviews. Performance Based Tariffs have allowed the utility to collect a bonus return on equity when LAUF is below a certain percentage and suffer a penalty when it exceeds a certain level. Fort Cobb Fuel Authority has petitioned the Commission to move away from a percentage LAUF-gas allowance to one based on customer density.
Pennsylvania	All LAUF gas is recovered by the utility and included within gas costs provided it is not excessive.
South Carolina	None
South Dakota	None
Tennessee	None
Texas	The main incentive is the negative incentive of disallowing gas costs associated with LAUF in excess of 5% of purchases. However, in a couple of instances the Commission has authorized "System Replenishment Fees" such as in Docket No. 9703 (T & L Gas) and Docket No. 10112 (Bluebonnet Natural Gas). These additional fees allow for expenditures targeted to reducing gas losses and replacement of selected lines.
Utah	Prudence of the utility's actions is judged in a PGA filing.
Vermont	The Board provides no specific incentives to manage LAUF.
Virginia	If LAUF rates are deemed to be too high, the Commission could find that the costs associated with all or some portion of the LAUF gas were imprudently incurred, and that their recovery should be disallowed. By statute, utilities are also allowed to recover qualifying infrastructure replacement costs through a rider (Chapter 26 (§ 56-603 et seq.) of Title 56 of the Code of Virginia).
Washington	None

Wisconsin	In general, the Commission does not provide an "incentive" to manage LAUF. However, there may be no rate recovery if LAUF exceeds the allowed amounts.
Wyoming	Historically, no incentive *per se* existed for a utility to manage LAUF. The incentive derives from not having to explain a deviation to the Commission.

State	**5. What actions do utilities in your state take to reduce LAUF gas? Are these actions based on a cost-benefit criterion?**
Alabama	Active cast-iron replacement; based on other criteria
Alaska	*See* the U-08-142 hearing (page 397-398 of transcript): "The only way you could be absolutely perfect is to have instantaneous meter reading on every location coming in and every location coming out. Enstar has tried over the years to do all kinds of things to make its [LAUF gas] less than -- than it is. We are -- even with this error we are substantially below what we see in the Lower 48 because of the newness of our system. We don't have pipes that leak. We don't tolerate leaks, but we've gone through and upgraded purchased meters to use new technology like ultrasonic (ph) meters which (indiscernible) makes some of these variances, their tolerance in reading is wider than in orifice meters and in turbine meters."
Arizona	Utilities are expected to take reasonable steps to reduce their LAUF gas.
Arkansas	The primary actions taken by Arkansas utilities is repairing and replacing pipeline infrastructure.
Colorado	None
Connecticut	The gas utilities decrease their LAUF gas through the repair and replacement of older mains, services and reduction in stolen gas.
Delaware	Generally, the utilities' overall operational maintenance programs address the theft and -loss issues that are the primary sources of LAUF gas; Commission Staff does not prescribe a cost-benefit criterion.
Florida	No actions have been taken to reduce LAUF gas.

Georgia	AGL: Failure to meet performance standards will result in penalties. Atmos: The utility is not under Commission mandate to reduce LAUF gas.
Idaho	The utilities have inter-disciplinary teams that regularly review the LAUF-gas audit processes currently in place. The teams investigate potential sources of LAUF gas and take remedial action as needed to continue keeping LAUF-gas levels low. Their business process identifies measurement errors from nominations, scheduling, flow volume allocation, and billing. The utilities also regularly make sure they are in compliance with the city gate's operational standards and the pass/fail requirements for customer's meters. Since Intermountain Gas has begun closely looking and reporting on LAUF gas, it has made alterations to the billing factors, gas reporting, and audit process. These alterations have helped the Company control the quantities and costs associated with LAUF gas (*See* the response to *Question 10* for results). These actions are based on a cost-benefit criterion. However, the utilities are most concerned with customer safety and avoiding operational fines for non-compliance at the city gate. There is not a one size fits all cost-benefit criteria, but the utilities use this type of analyses to evaluate particular projects. For example, Avista uses a cost-benefit approach to evaluate the probability and impact of leaks from the Aldyl A pipe on its system. From the results of this study, Avista determined the optimal timeframe for replacing the leak prone pipe.
Indiana	Due to utilities' desire to keep their LAUF gas at or below its established percentage and to provide safe and reliable service, utilities typically identify and repair the cause of any LAUF.
Iowa	Unknown
Kansas	Our previous response addressed the line loss limit in the PGA.
Kentucky	Leak surveys and associated repair/replacement of pipe that is leaking; meter testing programs to ensure proper and accurate measurement of gas flow through meter, metering all points of transfer of gas (i.e. customer meters, purchase stations, even free gas customers) to track volume of gas purchased versus volume of gas sold; actions are based on a combination of cost-benefit analysis and regulatory requirements.
Louisiana	The Commission takes no other actions other than disallowing recovery over the 6% threshold.
Maryland	Most recently, Maryland gas utilities have been expanding their pipe replacement programs to address a number of issues, including LAUF gas. In the current 2013 Maryland State Legislative session, both houses of the Legislature passed pipe replacement legislation, but this legislation has not been finalized nor signed by the Governor.
Massachusetts	*See* the previous response.

Michigan	The Commission requires prudent infrastructure maintenance and operating storage; if the utility has fewer losses than set in the rate case, it gets to keep any over-recovery.
Minnesota	The utilities have been encouraged to more precisely identify the source (or cause) of LAUF gas, which should lead to better control of these costs and assure that general ratepayers are the last resort for recovering these costs.
Mississippi	The larger systems (both investor owned and municipalities) reduce LAUF gas using proactive regular maintenance and control measures, taking action based on both cost-benefit and performance-based criteria. Smaller systems tend to be more reactive.
Montana	Montana utilities perform routine inspections, maintenance, and required upgrades to pipeline infrastructure. Cost-benefit analyses are expected for non-emergency procedures.
Nebraska	Unknown
Nevada	Neither SWG nor SPPC has an active program to reduce LAUF gas. Any actions are part of the normal course of operations, such as surveying for leaks in compliance with the PHMSA requirements, and repairing leaks when discovered.
New Hampshire	Utilities have cast iron and bare steel (CIBS) main replacement programs to upgrade the distribution systems (*see* docket DG 12-128). There are defined meter testing requirements in Commission gas rules (*see* Puc Chapter 500 gas rules). Automated meter reading has reduced estimated bills. These actions are based on a cost-benefit criterion, with the CIBS program. For other remedial actions, depending on the severity of the problem, cost-benefit is used more informally.
New Jersey	Utilities are involved in programs to replace cast iron and bare steel mains and services under "infrastructure" programs.
New Mexico	Utilities have meter testing, leak locating/repairing and pipeline safety programs. Perhaps utilities have taken other actions of which I'm unaware. Generally such programs are in compliance with state or federal requirements.
North Carolina	The utilities pursue a third-party reimbursement when a line breaks, and the Public Staff follows up.
North Dakota	Normal maintenance, based on a cost-benefit criterion

Ohio	The utilities has several categories into which LAUF gas is placed such as service theft, metering differences and errors, Dth to Mcf conversion, line strikes and line loss, and company use. If any of these categories appears to have changed substantially from a prior period, the company will form a team to determine the cause.
Oklahoma	Gas distributors perform frequent line surveys to detect for leaks. Capital improvements are based on safety and cost-benefit analysis.
Pennsylvania	Utilities take various actions to reduce their LAUF gas, including leak surveys, main replacement, meter testing/renewal programs, and theft programs. Some of these actions would be based upon a cost-benefit analysis.
South Carolina	Unknown
South Dakota	Nothing required by the Commission
Tennessee	Unknown
Texas	Utilities typically increase leak survey frequencies, review measurement history of large volume customers, and review the measurement records for purchase points. Additional measures include the estimation of known large leaks that occurred during the subject LAUF-gas period.
Utah	In its most recent Integrated Resource Plan, Questar Gas indicated it has implemented several practices to minimize LAUF gas, including: (1) *Temperature and elevation compensation.* In August of 2010, the Company began compensating for temperature and elevation in the computation of Dekatherms in its Utah service territory as ordered by the Commission. The effect has been a reduction in the volume of gas that is unaccounted for; (2) *Maintenance work on high pressure feeder lines.* When scheduled maintenance work requires the feeder line to be blown down, the line is allowed to feed down to the lowest possible pressure before being completely blown down. This minimizes the amount of gas that is blown down to the atmosphere. The pressure is recorded to allow the amount of gas that is blown down to be calculated; and (3) *Leak survey and repair.* The Company regularly conducts leak surveys and performs system maintenance as required. Additional leak surveys are conducted in accordance with applicable regulations in high consequence areas or areas with aging infrastructure.
Vermont	Vermont's natural gas utility (only one exists) has company policies to repair all discovered gas leaks promptly and to monitor/remediate customer meter accuracy. Furthermore, the company recently completed a program which replaced all cast iron and bare steel in their pipeline system. These actions are not based on a cost-benefit criterion.

Virginia	As previously noted, by statute utilities can recover qualifying infrastructure replacement costs through a rider (Chapter 26 (§ 56-603 et seq.) of Title 56 of the Code of Virginia. The definition of eligible infrastructure replacement costs is set forth in the statute.
Washington	Utilities are required to repair leaks upon discovery, replacement of services and small segments of mains. Cost-benefit is not usually the driver in these instances.
Wisconsin	There may be no rate recovery if LAUF gas exceeds the allowed amounts.
Wyoming	With the exception of a small gas utility, gas utilities have done a commendable job of constantly monitoring the metering values and LAUF gas, and responding in a timely manner to anomalies. Meter accuracy, line integrity and processing efficiency are typically discussed in rate cases.

State	**6. Does your commission feel that utilities could do a better job of managing their LAUF gas?**
Alabama	One can always do a better job, but it may not be cost effective. The answer is yes, they are doing a good job.
Alaska	Yes
Arizona	The Commission has not expressed an opinion on this in recent years.
Arkansas	There are always opportunities for utilities to improve on the management of their LAUF gas.
Colorado	This has not been a significant issue.
Connecticut	The Authority always expects the gas companies to mitigate their LAUF gas.
Delaware	While there is always room for improvement, generally the Commission feels that the utilities satisfactorily manage their LAUF gas.
Florida	The Commission has not taken a position.

Georgia	Don't know
Idaho	The Commission believes the utilities do a reasonable job of managing LAUF gas while keeping the system safe and costs down for ratepayers.
Indiana	The Commission believes that improvements are always welcome and can be made in all areas of operations by our gas utilities; however, the Commission is encouraged with the progress that gas utilities have made to maintain and update infrastructure needs; in particular, some utilities have trackers specifically for the replacement of cast iron and bare steel piping.
Iowa	Unknown
Kansas	Though the gas utilities in Kansas can always perform better, the most recent LAUF-gas percentage of these utilities ranged from .19% to 2.18%.
Kentucky	From a pipeline-safety branch perspective, most of our utilities are at or under the 5% LAUF-gas target and manage it due to it being tied directly to their revenue stream.
Louisiana	Some of the smaller gas utilities could do a better job, but overall the average is 3.62% and 2.47% for the group.
Maryland	This has not been an issue of concern, up to this point. See response to *Question 5* above.
Massachusetts	Unknown
Michigan	Yes, with what has been requested in recent rate case filings we definitely believe they could do a better job, assuming their requested LAUF-gas amounts are accurate, which we do not believe they are.
Minnesota	In 2012, the Commission asked MERC-PNG to provide more detailed explanations of its LAUF gas calculations to ensure that transportation service on its system was being correctly accounted for in the calculations. The Department of Commerce also requested that all utilities, if not already in place, create a program where they can estimate the amount of lost gas associated with a particular incident instead of charging gas costs to all ratepayers.
Mississippi	Don't know

Montana	The Commission encourages and supports pipeline maintenance and upgrades. The Commission is very active in the pipeline safety community.
Nebraska	No opinion adopted
Nevada	With respect to measurement errors, there is a concern that SWG reported a "gained gas" situation for both its Southern and Northern Nevada Divisions in the most recent annual rate adjustment application, Docket No. 12-06013. The result of this situation of metering more gas to customers than was metered into the system was a credit shrinkage rate for transportation customers. The "gained gas" situation in the Southern Nevada Division was the second consecutive year that this has occurred.
New Hampshire	From time to time Commission Staff will point out areas of concern that have resulted in Commission directives for corrective action by utilities (*see* cost of gas Docket No. DG 07-102, Order No. 24,798).
New Jersey	The Board feels that the accelerated infrastructure programs approved recently will improve the LAUF-gas levels.
New Mexico	Although the LAUF-gas percentage can vary, generally Staff has felt that it has been within acceptable standards.
North Carolina	While we would always welcome improvements, generally, no
North Dakota	Haven't addressed
Ohio	No, the utilities have a strong interest in minimizing their LAUF-gas levels.
Oklahoma	The Public Utility Division believes that all Oklahoma utilities are performing safety-first and cost-effective maintenance to the systems. We are unaware of any actions that could be taken by Oklahoma utilities that have not been addressed.
Pennsylvania	*See* the Commission's Proposed Rulemaking Order at Docket No. L-2012-2294746. The Commission believes that a consistent definition as well as established metrics will aid in ensuring LAUF is not a problem for Pennsylvania.
South Carolina	The Commission has not spoken on this issue.

South Dakota	No reason to believe so
Tennessee	Commission has not addressed this issue.
Texas	Commission Staff is committed to safety, believing that distribution utilities should always give maximum effort toward controlling and managing LAUF gas.
Utah	The Commission has not evaluated this issue.
Vermont	The Board has rendered no opinion on this topic.
Virginia	The Staff is not aware of any concerns that the Commission has regarding this issue.
Washington	No
Wisconsin	Our utilities have been managing their LAUF to allowable amounts.
Wyoming	The emphasis by the Commission has historically been directed toward metering accuracy (Section 405 of Commission Rules & Special Regulations), which has accounted for a significant percentage of the apparent LAUF gas. LAUF gas has not been a "hot button" issue in Wyoming, but has never been ignored, either.

State	**7. Has LAUF gas become a topic of concern in recent years triggering a commission investigation or other action?**
Alabama	No
Alaska	There has been discussion at adjudications for informational purposes, but no formal investigation or other action has occurred.
Arizona	No

Arkansas	Pipeline safety, gas leakage, and the control of pipeline erosion have and will continue to be a primary concern of the Commission and its Pipeline Safety Office.
Colorado	No
Connecticut	No
Delaware	This matter has been an item looked at more closely during the annual "GCR" and "GSR" filings in recent years; however, the Commission has not recently opened a Docket initiating an investigation for either gas utility serving Delaware customers.
Florida	No
Georgia	AGL: *See* Docket No. 15527—decided September 2002 Atmos: No
Idaho	No, not since Case No. INT-G-08-03
Indiana	The Commission is always monitoring the LAUF-gas percentages reported by regulated utilities; however, the issue has not become a topic of concern, yet.
Iowa	No
Kansas	No
Kentucky	With respect to gas cost and safety, LAUF gas has always been a topic of concern for the Commission; in response to growing concern about pipeline safety, KRS 278.509 was enacted in 2005, resulting in all five major gas utilities requesting and receiving authority to carry out accelerated main replacement programs, with accompanying surcharges.
Louisiana	No
Maryland	No

Massachusetts	No
Michigan	No
Minnesota	Yes, in 2008, the Commission asked the Department of Commerce to begin monitoring and reporting each utility’s LAUF-gas percentage. While LAUF-gas percentages should be relatively stable over time, the Commission believes that monitoring this number and finding explanations for any exceptions could be useful. Therefore, the Commission will request that the OES [the Office of Energy Security was a previous name used by the Department of Commerce] develop and report in next year's AAA review a summary and comparison of each regulated natural gas utility's LAUF-gas percentages.
Mississippi	Not across the board – this is dealt with on a case-by-case basis – *see* City of Moss Point Docket as an example
Montana	No Commission action, but pipeline safety Staff does monitoring, as reported on the PHMSA 7100 form, Gas Annual Report.
Nebraska	No
Nevada	In 2005, Staff discovered during its audit in Docket No. 05-5015 that SWG was incorrectly calculating the shrinkage rate by including the volumes of transportation customers who had negotiated contracts that exempted them from paying the shrinkage rate. In the Southern Nevada Divisions, these volumes represented approximately 50% of the volumes on the distribution system. When Staff corrected this error in 2005, instead of just doubling the shrinkage rate as one would expect, the shrinkage rate increased ten-fold because the LAUF-gas percentage had tripled from 0.3% to 0.9% and the cost of gas had increased more than 50% at the same time that the error was corrected. Transportation customers subject to the shrinkage rate had been accustomed to paying approximately one-tenth of a cent per therm in the shrinkage rate suddenly saw the shrinkage rate increase to approximately one cent per therm in 2006. The Commission opened Docket No. 08-03033 as a result of a complaint from one of these transportation customers. As described in our response to *Question 2,* the result of this investigatory docket was to create a separate high-pressure and low-pressure shrinkage rate in the Southern Nevada Division.
New Hampshire	Yes, *see* DG 07-102 and DG 09-050
New Jersey	Concerns relate to the replacement of cast iron and bare steel main but not directly related to concerns about the level of LAUF gas.

New Mexico	No
North Carolina	No
North Dakota	No
Ohio	No
Oklahoma	No, however, the Commission has been involved with stakeholder meetings concerning PHMSA regulations and the possible need for state level legislation.
Pennsylvania	Yes, *see* the Commission's Proposed Rulemaking Order at Docket No. L-2012-2294746
South Carolina	No
South Dakota	No
Tennessee	No
Texas	As mentioned above, the Commission has had two rate cases which approved System Replenishment Fees, addressing the reduction of LAUF gas.
Utah	No
Vermont	Somewhat, but not enough to trigger any action
Virginia	No
Washington	No
Wisconsin	No

Wyoming	One gas utility was challenged to reduce its LAUF-gas level (around 4-5%) and ultimately was imputed a target LAUF gas, above which level they would 'eat' the cost of additional losses. This action was a result of analysis of a PGA filing, in the 2001-2004 timeframe, leading to improvements to the company's pipe integrity, metering accuracy, and reporting, and ultimately brought the LAUF gas in line with comparable utilities. Every rate case involving a gas utility I have been associated with has included some discussion and analysis of LAUF gas. Utilities are openly compared with other Wyoming gas utilities, challenged to explain differences and trends, and have been directed at times to address and provide special reporting of their LAUF-gas levels.

State	**8. Has your commission investigated the relationship between LAUF gas and pipeline safety? Has your commission, for example, ever relied on historical statistics on LAUF gas to encourage or require a utility to reduce its pipe leaks by more prompt detection or repair?**
Alabama	No, we have not investigated the relationship between LAUF gas and pipeline safety. In the past years, we have monitored the utilities' Annual Reports to get their reported LAUF gas. Anything above 5% required a site visit to the utility. During this visit, a determination was made as to the source(s) of the LAUF gas, then a procedure was put into place to bring the LAUF gas back to an allowable amount. For the past three years, we have been gathering data from the Annual Reports to insert into our Risk Ranking Index. We are trying to develop a tracking system to verify which utilities might consistently have excessive LAUF gas.
Alaska	No
Arizona	There was a case with a small company in the 1990s where its LAUF gas was high and it led to a reduction in leaks.
Arkansas	Yes, the Commission has in past proceedings relied on historical statistics in capping the LAUF-gas rate as an incentive for the utility to repair natural gas leaks.
Colorado	No, it has been more of an accounting issue and measurement error issue.
Connecticut	The Authority has investigated LAUF gas as part of the company's rate case; it is well known that older leaking pipes cause a portion of the LAUF gas but customer theft is also a source; the Authority expects that LAUF gas will decrease as a result of cast iron replacement programs and the reduction of theft of service.

Delaware	No, this Commission generally relies on the utility to identify and reduce its pipeline leaks through their ability to detect and repair; this is monitored thru Commission Staff in the Pipeline Safety roles.
Florida	The Commission Staff relies on the total number, frequency, and category of leaks to determine if a utility needs to take additional action to reduce its pipe leaks; Staff does not use historical statistics on LAUF.
Georgia	All utilities are required to report their LAUF percentage on their annual PHMSA 7100 report. The Commission's Pipeline Safety Staff looks at LAUF gas as part of the regular comprehensive inspections, and they consider the LAUF-gas percentage that they report as one component of our utility risk ranking. Typically, after the 7100s are finalized each year, PHMSA will request that the Commission follow up on the utilities that report above 5% lost gas.
Idaho	Yes, the Commission Staff evaluated Avista's Aldyl A Pipe Replacement Program in Case No. AVU-G-12-07. As part of the evaluation, Staff reviewed the Company's study showing the number of leaks estimated to occur given different replacement timeframes. The Commission has relied on historical statistics on LAUF gas to encourage or require a utility to reduce its pipe leaks by more prompt detection or repair. In PGA filings the Commission reviews historical statistics on LAUF gas to track trends. For example, when Intermountain Gas had a significant increase in LAUF gas during the 2008 PGA, the Commission placed a cap on the allowable amount of recoverable LAUF gas. As stated in response to *Question 1*, the Commission also ordered the Company to file reports indicating how it planned to "outline steps toward identifying the sources of lost and unaccounted-for gas and work toward improvement." (Order No. 30649) These reports can be found by following the link provided in response to *Question 1*.
Indiana	No
Iowa	Unknown
Kansas	For small systems, the Commission pipeline safety section reviews LAUF gas on an annual basis. If the value is more than 4%, Staff seeks to discover the reason up to and including requiring additional leak surveys which are witnessed by Staff. It is our experience the error is typically an accounting error or inaccurate meters instead of leaks. For large systems, LAUF gas on a statewide level is not an effective tool to evaluate leakage. We have not required LAUF-gas calculations on a city-by-city basis; that is, tracking the aggregate sales points back to each purchase point.
Kentucky	I am not aware of a formal investigation on a relationship between the LAUF gas and pipeline safety conducted by the Commission; however, the Pipeline Safety Branch has reviewed annual reports for instances where a utility's LAUF gas is greater than 5% and notified the utility that steps should be taken to reduce its LAUF gas.

Louisiana	No, an investigation has never been launched, but Commission Staff has discussed it with companies that were above the 6% threshold. This resulted in one of the companies discovering smaller leaks and repairing pipes, which brought it down to below 6%.
Maryland	No, however, as noted in the response to *Question 5*, the gas utilities operating in Maryland have been encouraged to improve the reliability and safety of their individual distribution systems by investing in more pipes and mains replacement. This will have the salutary effect of improving reliability, safely, and reducing the loss of natural gas through leaks on the individual gas utility distribution systems.
Massachusetts	No
Michigan	No
Minnesota	Yes, the initial comparisons made were between the percentages reported in the annual true-up filings and the percentages reported each year in PHMSA Form 7100.1-1. The Department of Commerce has observed that the LAUF-gas percentage utilities reported in PHMSA on Form 7100.1-1 often does not match the LAUF gas data that they provide to the Department of Commerce and the Commission for cost-recovery purposes. The Department of Commerce has recommended that regulators exercise caution when using LAUF-gas figures from the PHMSA forms in an analysis.
Mississippi	Yes, our Pipeline Safety Department monitors each system annually.
Montana	*See* response to *Question 7*
Nebraska	No
Nevada	No, as stated above, the distribution systems in Nevada are relatively new compared to other states. Leakage has not been a major concern in Nevada.
New Hampshire	Not formally, however, the Gas Safety Division requires each gas utility to file copies of its periodic PHMSA reports on unaccounted for gas and will follow up directly with the utility company if the reported figures are outside the norm. The Commission has relied on historical statistics on LAUF gas to encourage or require a utility to reduce its pipe leaks by more prompt detection or repair; *see*, for example, Docket No. DG 05-055 (Order 24,464) and DG 05-158 (Order 24,536).
New Jersey	The Board looks at the leak rate, rather than the volume of LAUF gas.

New Mexico	The Commission conducted an investigation into a gas distribution line explosion in Santa Fe about a decade ago. This resulted in an enhanced program of gas leak location and repair. I do not know if LAUF gas historical analysis was part of that investigation, but it is possible. A review of the record of that case should answer that question.
North Carolina	Yes, to both
North Dakota	Yes
Ohio	No, the utilities have taken it upon themselves to monitor the age and conditions of their pipes and if in their opinion a safety risk exists, the utility will seek to replace the pipe prior to its failing and seek recovery of the cost through an accelerated main-line replacement program.
Oklahoma	Yes
Pennsylvania	*See* the Commission's Proposed Rulemaking Order for Docket No. L-2012-2294746. The Commission's Gas Safety Division within the Bureau of Investigation and Enforcement could require a utility to reduce leaks or repair a pipe based upon present conditions, including historical LAUF gas. As mentioned on page 2 and page 11 of the Proposed Rulemaking Order, the Commission views the adoption of a LAUF-gas definition and metric to be a potential addition to its safety efforts.
South Carolina	No
South Dakota	No
Tennessee	Pipeline Safety Division regularly inspects utility pipelines. This has not been a major issue.
Texas	Each safety evaluation of a gas distribution system includes a review of the utility's LAUF gas. The most recent year ending data are reviewed and documented within the Pipeline Safety inspection package. If the LAUF exceeds 10% for the period under review, the inspector will investigate further through review of the most recent purchase and sales figures available. If the inspector believes the utility has not taken proper measures to determine the cause of the high volume of LAUF gas, an alleged violation is cited. Through the Pipeline Safety Division review of the utility's Plan of Correction, the Commission monitors the utility's progress to resolve the issue and continues to monitor the situation during the next scheduled inspection.
Utah	No

Vermont	No
Virginia	Yes
Washington	Yes, pipeline Staff have used the information reported to compare LAUF gas with the number of leaks reported for the same calendar year; this is done mostly to determine the accuracy of the information they are reporting.
Wisconsin	The LAUF-gas percentage has historically been less than 2%, and sometimes even positive. Our experience is that LAUF-gas is largely attributable to metering differences.
Wyoming	The Commission has not investigated the relationship between LAUF gas and pipeline safety, but has a section devoted to facilities integrity and safety; and the Commission has trusted the historical statistics in its determinations regarding utility facilities.

State	**9. Do all the utilities in your state:** **a. Use the same definition for LAUF gas?** **b. Treat LAUF gas the same for ratemaking?**
Alabama	Yes, for both
Alaska	ENSTAR's tariff does not define LAUF gas specifically. It is found in part of the Company Use definition found at Tariff Sheet No. 23.
Arizona	Unknown, for both
Arkansas	(a) Generally, yes; LAUF gas in Arkansas is generally considered to be natural gas that is purchased and then loss due to pipeline leakage, accounting errors, and/or inaccurate measurement; (b) Generally, yes.
Colorado	Yes, for both

Connecticut	Yes, for both
Delaware	(a) The term Unaccounted For Gas is defined in Chesapeake Utility Corporation's tariff, but is not a defined term in Delmarva Power & Light Company's; (b) LAUF gas is treated the same for both of Delaware's regulated natural gas utility companies.
Florida	Yes, for both
Georgia	AGL: As a result of Docket No. 15527, AGL was required to determine the contributing factors for LAUF gas. Therefore, AGL classifies the gas into various components. Atmos: "Unaccounted for gas" is gas lost that the utility cannot account for as usage or through appropriate adjustment. Adjustments are appropriately made for such factors as variations in temperature, pressure, meter-reading cycles, or heat content; calculable losses from construction, purging and line breaks, where specific data are available to allow reasonable calculation or estimate; or other similar factors. (Taken from Instructions for Completing Form PHMSA F 7100.1-1 (Rev. 01/11)); (b) No, *see* above response.
Idaho	(a) Yes; (b) *See* the response to *Question 3*
Indiana	(a) Yes, (b) No
Iowa	Yes, for both
Kansas	Yes, for both
Kentucky	(a) For cost purposes, LAUF gas is considered the difference between sales and purchase volumes; (b) All the small LDCs using PGA mechanisms apply the same 5 percent "limiter" to LAUF-gas pass-through. The major LDCs pass through their pipeline suppliers' LAUF gas. Their system LAUF gas tends to be in the 1 to 3 percent range so is not an issue with respect to the 5 percent limiter. All of the system LAUF gas below 5 percent is passed through gas cost.
Louisiana	Yes, for both
Maryland	(a) Yes, however, the adjustment they make to account for LAUF gas varies. For example, Baltimore Gas and Electric calculates monthly the LAUF-gas factor and performs the adjustments monthly. Washington Gas Light Company and Columbia Gas of Maryland calculate LAUF gas quarterly, and apply the adjustments quarterly for the PGA and monthly for transportation and shopping customers; (b) yes.

Massachusetts	Yes, for both
Michigan	Yes, for both
Minnesota	(a) Yes, all of the utilities use the same definition for responding to the Department of Commerce discovery requests. These responses are then used by the Department in the summary and comparison that is included in its annual report to the Commission; (b) Yes, all of the utilities recover LAUF gas in their annual gas cost reconciliation and true-up mechanism. There are, however, minor differences in how the utilities account for lost gas that is attributable to a specific incident or party.
Mississippi	Yes, for both
Montana	(a) LAUF gas is considered to be product that is observed to enter the system, but is not observed to exit the system; (b) *See* response to *Question 1*.
Nebraska	(a) Unknown; (b) the Commission regulates three gas utilities -- two use the gas cost adjustment and the third, which operates a choice gas program, recovers LAUF gas volumetrically from suppliers based on an allocation.
Nevada	(a) Yes. Both SWG and SPPC define LAUF gas or shrinkage similar to the Commission's definition in NAC 704.960 for "Unaccounted for Gas." NAC-704.960 --"Unaccounted for Gas" defined. (NRS 703.025, 704.210, 704.991) --"Unaccounted for Gas" means the difference between the total amount of gas delivered to a utility and the total amount of gas which is used, sold, or delivered to other entities by the utility. (b) Yes and no. Sales customers for both SWG and SPPC pay for LAUF gas as a component of purchased gas costs. However, SPPC recovers LAUF gas from transportation customers using an in-kind contribution and SWG uses the shrinkage rate methodology to recover LAUF gas from transportation customers. Furthermore, the shrinkage rate is calculated differently in SWG's Southern and Northern Nevada Divisions.
New Hampshire	Yes, for both
New Jersey	(a) Generally, yes; (b) yes
New Mexico	(a) There is not a standard definition in the Commission rules; (b) Yes

North Carolina	Yes, for both
North Dakota	(a) Not sure; (b) yes
Ohio	Definitions vary by utility; all costs recovered through the PGA
Oklahoma	No, for both
Pennsylvania	(a) Not currently, *see* the Commission's Proposed Rulemaking Order at Docket No. L-2012-2294746 aimed at establishing a uniform definition; (b) Yes, LAUF gas is treated similarly for all jurisdictional utilities despite the differences in definition.
South Carolina	Yes, for both
South Dakota	Yes, for both
Tennessee	(a) Not known; (b) no answer
Texas	(a) Generally speaking, yes, but there can be subtle variations; (b) Again, generally speaking, yes, but some computation methods might differ in subtle ways, such as accounting for transportation (only) volumes inside a distribution system and their relationship to the purchase and sales volumes.
Utah	There is only one investor-owned utility in Utah under the Commission's jurisdiction. It is unknown how the three small municipal gas companies treat both items.
Vermont	Vermont has only one gas utility.
Virginia	Yes, for both
Washington	(a) For the most part, yes; (b) yes
Wisconsin	(a) Yes; (b) the Commission treats LAUF gas the same for revenue requirement purposes but may have different ratemaking for recovery purposes.

Wyoming	(a) Yes; (b) Yes, although some have unique applications.

State	10. Do utilities in your states quantify LAUF gas by source? These sources can include measurement error, pipe leaks, stolen gas, accounting error.
Alabama	These sources can include measurement error, pipe leaks, stolen gas, accounting error. Utilities do not calculate the effect of pipe leaks on LAUF gas. Generally, utilities do not publicly report any calculations; but there is a line on EIA 176 report that requires utilities to identify "losses from leaks, damages, accidents, migration and/or blowdown with the reporting state."
Alaska	ENSTAR does not quantify LAUF gas by source; it is all lumped together. *See* Volumes and Gas Received and Sold in GCBA filings.
Arizona	Not that I'm aware of.
Arkansas	LAUF gas is generally calculated in total and is not broken down by source.
Colorado	No
Connecticut	No
Delaware	During the discovery process of the GCR and GSR cases, the utilities are usually asked to provide their annual PHMSA reports which include leaks. During cases the utilities may also be asked for the data on pipeline leaks or breaks caused by third parties during the past 12 months. The responses should address the extent of such occurrences, the estimated volume of gas lost, and what recoveries were sought and obtained from any responsible third parties. LAUF gas is reported as a total percentage in the annual filing and is not broken down by source; this information is not public; however, the LAUF percentage contained in annual filing is public.
Florida	LAUF is calculated for main line leaks or breaks; this information is not publicly reported.

Georgia	For both_AGL and Atmos, breakdowns include consumption on inactive meter, third party damages, meter/measurement error, and leaks. <u>AGL</u>: Required to file monthly and annual reports <u>Atmos</u>: The information is provided in the Annual Distribution Operator report filed with PHMSA.
Idaho	Intermountain Gas identifies and reports sources of LAUF gas as part of its semi-annual reports provided to the Commission. Specifically, it historically tracks metering issues, drive rate errors, and pressure errors by service area region. Avista tracks similar items internally through its accounting system, but does not provide results to the Commission outside of discovery in a general rate-case proceeding. The utilities do estimate LAUF gas caused by leaks.
Indiana	The Commission is always monitoring the LAUF-gas percentages reported by regulated utilities; however, the issue has not yet become a topic of concern.
Iowa	Unknown
Kansas	No, all sources are combined into one calculation.
Kentucky	For cost pass-through purposes, rarely; all PGA applications are public record unless confidentiality of certain information is requested. Information relating to the utilities' calculation of their gas cost pass-through is never held confidential unless it contains proprietary supplier information.
Louisiana	Not in anything reported to the Commission; they may have internal auditing and reporting
Maryland	No
Massachusetts	No, the LAUF gas reported include (a) company use gas; and (b) unaccounted for gas.
Michigan	I believe they must break it down into more specific lost gas categories, but I don't know if the Commission is presented with each category or not. Stolen gas on MichCon's system is a big problem.

Minnesota	Generally LAUF gas is not reported by source with the exception of gas lost due to leaks caused by contractors striking a gas main; only if the leak was caused by an independent contractor, or other party, can the cost of the lost gas be recovered from the contractor or the party that caused the damage. Reporting of LAUF gas due to contractor main strikes has just started. The utilities may or may not claim this is non-public information. One utility provided the Department of Commerce with specific data for each event attributable to a given party in response to a discovery request. The Department does not believe this information was formally filed, but believes the costs and gas lost information should be public, but contractor names and addresses probably would be considered confidential.
Mississippi	Varies by utility
Montana	Utilities use all sources available to determine the volume of LAUF gas. Again, this (the amount, not the source) is reported on the PHMSA 7100 form which might indicate an action to be taken in a certain area of the utility system. The 7100 form is available publicly through the Commission or through PHMSA.
Nebraska	No
Nevada	Yes and no: SWG will bill the responsible party for the estimated gas lost from excavation damage (*see* PHMSA Form F-7100.1). These volumes will be recorded in SWG's Unaccounted for Gas Report.
New Hampshire	No
New Jersey	No
New Mexico	I don't know if any of our three regulated utilities quantify LAUF gas by source for internal purposes. I don't believe such quantification is routinely reported to the Commission.
North Carolina	In order to file suit against parties that negligently cut their lines, utilities calculate gas lost from excavation damage. However, this is not aggregated and reported.
North Dakota	Not sure
Ohio	Yes, as contained in our response to *Question 5*, but not publicly reported

Oklahoma	Varies by utility; each utility internally tracks lost gas by pipe segments.
Pennsylvania	Not routinely, however, as part of individual LAUF-gas reduction plans, utilities have identified potential losses by cause. If part of a joint settlement, these calculations would be publically available within the PGC or GCR proceeding. The Commission's Joint Report, attached to the Proposed Rulemaking Order at Docket No. L-2012-2294746, pages 5-7, addresses the definition of LAUF gas in Pennsylvania.
South Carolina	No
South Dakota	No
Tennessee	Not known
Texas	Some utilities, in the case of large leaks, estimate calculations of gas loss. This is particularly true with third- party damages where the hole size and leak duration are known values. We have also seen calculated true-ups in situations of measurement error (wrong multiplier used or wrong meter index installed).
Utah	*See* response to *Question 12*
Vermont	No
Virginia	Yes, and they are publicly reported
Washington	No, calculation is as follows: [(purchased gas + produced gas) minus (customer use + appropriate adjustments)] divided by (purchased gas + produced gas) equals percent unaccounted for.
Wisconsin	No, leaks surveys are required to be conducted annually in most areas; leaks are generally repaired when discovered.
Wyoming	This data separating gas leaks from metering/accounting error is typically established at rate cases. Both the Questar and SourceGas rate cases cited above have discussion of pipe leakage within the maintenance sections of testimony. In the case of Questar, it covers adoption of a relatively poorly designed and maintained distribution system near Kemmerer, Wyoming, the corrective measures, and the resultant leakage reductions. The calculations are available to the public through our website.

State	11. Does your commission require utilities to report periodically the amount of their LAUF gas?
Alabama	No
Alaska	No, we do not require ENSTAR to file the information. However, it is filed in the GCBA quarterly filings and the information is used to support the Shippers Share filing.
Arizona	No
Arkansas	PHMSA requires gas utilities to annually report the Unaccounted For Gas percentage on its system for the 12 months ending June 30th.
Colorado	None
Connecticut	Yes
Delaware	For Chesapeake Utilities Corporation, Commission Staff reviews the actual Unaccounted For Gas volumes on an annual basis and then reviews the Company's performance under the Unaccounted For Gas Incentive Mechanism in the next base rate proceeding.
Florida	No
Georgia	AGL: Required quarterly and annual reports to the Commission, pursuant to Docket No. 15527 Atmos: A copy of the annual PHMSA 7100 is provided to the Commission's Facilities Protection Unit.
Idaho	The utilities report LAUF gas as part of each annual PGA filing, and in the FERC Form 2.
Indiana	Yes, the utilities are required to report their LAUF gas within the GCA/PGA process and some are required to provide annual updates through a compliance filing.

Iowa	Yes, in both the annual report IG-1 and the annual PGA filings
Kansas	Yes, annually through the PGA report, FERC Form 2 filings and Pipeline Safety reports
Kentucky	Unaccounted for Gas is reported as the difference between purchases and sales in gas utilities' Annual Reports, which are required to be filed with the Commission before March 31st. For major LDCs' Annual Reporting requirements, Unaccounted for Gas is divided into production system losses, gathering system losses, transmission system losses, distribution system losses, and storage system losses.
Louisiana	Utilities report their LAUF gas monthly in the PGA filings and a three-year average is used in the monthly calculation.
Maryland	Generally, the gas utility companies in Maryland report their LAUF-gas numbers when they make their annual PGA/PGC filings. However, one gas utility, Baltimore Gas and Electric Company, files monthly reports of their LAUF-gas numbers with the Commission.
Massachusetts	Yes, gas utilities are required to report LAUF-gas information in their annual reports to the Commission.
Michigan	Yes, they report actual last gas annually in the GCR.
Minnesota	Yes, starting with annual fuel reports for fiscal-year 2008, the Commission asked the Department of Commerce to compile a summary and comparison of each utility's LAUF-gas percentage.
Mississippi	No
Montana	Only in the context of a gas tracker or other cost recovery proceeding
Nebraska	Not explicitly, but to the extent utilities want to recover their LAUF-gas costs in the gas cost adjustment, they must support their request with information on all costs they are seeking, which would include LAUF-gas related if they are seeking it. Two utilities provide it as part of a confidential filing.
Nevada	Yes and no: SWG files "Unaccounted for Gas Reports" with the annual rate adjustment application to support their calculation of the shrinkage rate. SPPC does not report its LAUF-gas percentage to the Commission.

New Hampshire	Yes, in addition to the PHMSA reports described earlier, utilities are required to show the actual LAUF-gas volumes as part of each 6-month cost of gas reconciliation.
New Jersey	Reported in annual BGSS filings
New Mexico	Not to my knowledge; the rules do not, and I am not aware of any specific case requirements on any of our gas utilities.
North Carolina	Yes, LAUF gas is reported in monthly deferred account reports and the annual review of gas costs.
North Dakota	No
Ohio	No, other than the audits, LAUF gas is not reported.
Oklahoma	Yes
Pennsylvania	Yes, *see* the Commission's Proposed Rulemaking Order at Docket No. L-2012-2294746, page 3 for more discussion
South Carolina	No
South Dakota	Only the percentages, which when applied to a price result in a dollar amount
Tennessee	No
Texas	Yes, we receive LAUF volumes and percentages annually, from both investor owned and municipal gas distribution utilities.
Utah	Yes, in the annual Integrated Resource Plan filed with the Commission.
Vermont	No

Virginia	The Staff is not aware of any concerns that the Commission has regarding this issue.
Washington	No, however, the Commission does report this information on its webpage with data found in the FERC Form 2.
Wisconsin	The Commission requires utilities to report the amount of their LAUF gas on an annual basis.
Wyoming	LAUF gas is included in PGA calculations and is reported in utility annual reports.

State	**12. Are there public statistics on LAUF gas percentages by utility over an historical time frame?**
Alabama	Yes, it is reported on each utility's annual report (EIA 176).
Alaska	The volumes and percentages can be found in the Shippers Share filings.
Arizona	No
Arkansas	Yes
Colorado	No
Connecticut	LAUF data is publicly available in rate cases and company order compliance filings.
Delaware	There is reporting available from previous "GCR" and "GSR" Dockets through Discovery Requests; generally, these are not posted for the public.
Florida	No
Georgia	AGL: Quarterly/annual filings in Docket No.15527 are required and filed publicly. Atmos: No

Idaho	LAUF gas is reported by LDCs in the FERC Form 2. Therefore, these results could be tracked over a historical timeframe.
Indiana	No, there is not one comprehensive document that contains this information; however, Petitioner's filings before the Commission are public record, which could be used to compile such information.
Iowa	Yes, the annual reports
Kansas	Yes, annually through the PGA report, FERC Form 2 filings and Pipeline Safety reports
Kentucky	Utilities' Annual Reports, which contain the Unaccounted for Gas reporting requirement, are available on the Commission's Web site. This information is not compiled into a summary report.
Louisiana	While there are no public statistics available, the LAUF-gas three-year average spreadsheets are kept by Commission Staff and reports or tables could always be compiled upon request.
Maryland	No
Massachusetts	Yes, annually
Michigan	Not sure, we may have this data but I don't know if it is publically available.
Minnesota	Yes, annual LAUF-gas percentages, reported by the utilities since fiscal-year 2008, are publically available in the Department of Commerce's Annual Fuel Reports (the docket numbers are listed above in response to *Question 1*.
Mississippi	No
Montana	The filed documents in cost recovery proceedings are public information. However, this data has not been compiled into simple tabular form.
Nebraska	No

Nevada	No, the Commission does not have a process to maintain LAUF-gas percentages over an historical time frame. If one needed this information, one could review the Unaccounted for Gas Reports filed in SWG's past annual rate adjustment applications or the public statistics reported by SWG and SPPC in the PHMSA Gas Distribution System Annual Reports.
New Hampshire	No
New Jersey	*See* BGSS filings
New Mexico	The regulated gas utilities file their PGA factors prior to changing them. Each PGA factor filing includes the purchase/sale ratio. These factor filings represent an historical record of LAUF gas as used to calculate rates, but not a measured account of LAUF gas over a specific period.
North Carolina	Yes, for at least a few years, in the Pipeline Safety Annual Reports required by PHMSA
North Dakota	No
Ohio	No
Oklahoma	Yes
Pennsylvania	*See* the Commission's Proposed Rulemaking Order for Docket No. L-2012-2294746 (page 9 and 10), for current levels. Otherwise, all data filed within PUC Annual Reports, or the DOT Annual Reports would be publically available as well as PGC or GCR rates.
South Carolina	No
South Dakota	No
Tennessee	No

Texas	The data are published on the Commission's web site and is updated annually. It is found in Tables 2 and 3 of the Gas Utilities Annual Statistical Reports. Several (fiscal) years of data are available at this site.
Utah	Some information is available in Questar Gas Companies IRPs filed in years 2010, 2011, and 2012.
Vermont	No
Virginia	No
Washington	Data from the FERC Form 2 is available in the Commission's statistics reports for each investor owned utility posted on the Commission's webpage.
Wisconsin	There are there public statistics on LAUF-gas percentages by utility over an historical time frame.
Wyoming	The information is available, requiring collection across several documents such as annual reports and previous pass-on supporting documentation. This collection (a) has been performed at various times by analysts processing filings, (b) has in the past been provided upon request to legislators and Commissioners, and (c) may reside in the archives of some analyst's computers but is not maintained and updated as a simple public document.

State	**13. Does your commission have estimates of the increase in purchased gas costs attributable to LAUF gas?**
Alabama	No
Alaska	No, we do not have an estimate in increase of purchased gas attributable to LAUF gas. It is lumped in with Company use when the estimated purchases are provided.
Arizona	No
Arkansas	No

Colorado	No
Connecticut	LAUF gas has a very low percentage and the impact on gas costs is very small.
Delaware	Typically, utilities account for the LAUF gas in their projected sales and requirement reports; these reports do not include a financial estimate.
Florida	No
Georgia	No
Idaho	The Commission looks at this as part of each PGA filing. Typically, LAUF gas is a negligible piece of the purchased gas costs (less than 3% of total throughput).
Indiana	Estimates for such information are readily available in the regulated utilities' GCA/PGA filings.
Iowa	Unknown
Kansas	No, but it would be easy to calculate from the reports listed above. As stated earlier, Kansas gas utilities' most recent LAUF-gas percentages ranged from .19% to 2.18%.
Kentucky	Not as such, but for the most part increases due to LAUF gas are 5 percent or less.
Louisiana	No, but again, the information from the LAUF-gas spreadsheets is available and could be used to track the increase.
Maryland	No, LAUF gas costs are provided by gas utilities in their annual PGA/PGC filings.
Massachusetts	No
Michigan	Staff could calculate that value.
Minnesota	No, the estimates are based on volumes of gas rather than the dollar amount of the losses.

Mississippi	No
Montana	The increase in customer costs is simply the product of the allowed LAUF-gas percentage and the average procurement cost of gas.
Nebraska	No
Nevada	No, however, this number can be calculated in the annual rate adjustment applications by taking the difference between (a) the cost of gas on a purchased-volume basis and (b) the cost of gas on a sales-volume basis.
New Hampshire	Approximately 1-2% of total purchased gas volumes are LAUF-gas related. If a utility's annual gas purchases are $100 million, approximately $1-$2 million would be the attributed to LAUF gas.
New Jersey	No
New Mexico	*See* answer to *Question 12*
North Carolina	Data is available but it would have to be calculated.
North Dakota	No
Ohio	No, if LAUF gas exceeds the 5% limited contained in the Ohio Administrative Code, the Commission can disallow a portion of the costs in the utility's PGA.
Oklahoma	Yes
Pennsylvania	Increases in PGC or GCR rates attributed to LAUF gas may be encompassed within each PGC or GCR case. However, the Commission does not compile statistics on actual cost implications across Pennsylvania. As an aside, the Commission has estimated these losses in Commission's Proposed Rulemaking Order at Docket No. L-2012-2294746, see page 10 of Commission's Joint Report.
South Carolina	No

South Dakota	Yes, by applying the percentages passed through the rates
Tennessee	No
Texas	No, but this could easily be approximated by using the average gas costs or in the Distribution Annual Reports
Utah	No
Vermont	No
Virginia	No
Washington	No
Wisconsin	The Commission has estimates of the increase in purchased gas costs attributable to LAUF gas. In general, LAUF can be expressed as a percent of the utility's average weighted cost of gas.
Wyoming	Yes, this data point is typically reviewed in rate cases and PGA filings.

State	**14. Does your commission monitor LAUF gas over time? If so, how does it use the information?**
Alabama	The Gas Pipeline Safety Division does the monitoring.
Alaska	No
Arizona	We at times will look at it in rate cases, but it hasn't been a concern in recent years.
Arkansas	Yes, for specific regulatory purposes, the Commission may monitor a utility's LAUF gas.

Colorado	No
Connecticut	The Authority monitors LAUF through rate cases and the compliance filings.
Delaware	Generally, this Commission monitors LAUF gas in relation to the annual GCR and GSR filings; typically, during the course of these annual filings the utilities are asked, through data requests, to provide a summary of LAUF-gas volumes for prior periods; this information is used as a comparison to the most current LAUF-gas information provided.
Florida	No
Georgia	AGL: Yes, quarterly/annual reports are required. The Staff reviews and monitors the filings to ensure compliance with Docket No. 15527. Atmos: A copy of the annual PHMSA Form 7100 is provided to the Commission's Facilities Protection Unit. The Facilities Protection Unit monitors the filings for trends.
Idaho	The Commission monitors LAUF gas trends in each annual PGA filing. The information is used to track changes and to determine whether it is necessary to request more specific information, reporting, or remediation. For example, the Commission ordered Intermountain Gas to begin submitting reports aimed at improving LAUF-gas levels because of increasing historical trends. Since that time the Company has shown improvement.
Indiana	Yes, it is monitored in the GCA/PGA filings within Schedules 11 & 11A on a quarterly basis; the information assists in determining if the utility is having any distribution-system issues.
Iowa	No
Kansas	Yes, there is a penalty mechanism in the PGA. The LDC is not allowed to recover the Purchased Gas costs associated with a LAUF-gas percentage in excess of 4%.
Kentucky	Yes, this is done through annual reports submitted to the Commission's Pipeline Safety Branch as well as during compliance inspection. Generally, this information is reviewed for LAUF gas that is greater than 5%. Utilities may be contacted to see what process and/or procedures are in place to address and reduce LAUF gas.
Louisiana	Yes, the Commission has been keeping LAUF-gas spreadsheets for all regulated companies since the PGA order went into effect in 1999. The information is mostly used to verify that the company is using the correct PGA amount on customer bills. It has also been used in discussions with the companies to alert them to possible leaks or other problems.

Maryland	No
Massachusetts	Yes, the Department monitors the changes from year-to-year; it could investigate if there is significant variation.
Michigan	Yes
Minnesota	The Department of Commerce monitors the annual LAUF-gas percentages and notes exceptions or unusual amounts.
Mississippi	Pipeline Safety monitors all systems annually. If LAUF gas becomes a concern, they will investigate to determine the cause and assist utilities in developing plans to remedy the problem.
Montana	The utilities monitor the LAUF-gas percentages. The Commission is typically concerned with LAUF gas with respect to pipeline safety, customer rate impact, and as an indicator of the overall health and reliability of pipeline infrastructure.
Nebraska	No
Nevada	The Commission does not have a formal process to monitor LAUF gas over time. However, SWG does provide its Unaccounted for Gas Reports in the annual rate adjustment application which is used to support the calculation of the shrinkage rate. Furthermore, Commission Staff will review the PHMSA Gas Distribution System Annual Reports for both SWG and SPPC to monitor the reported LAUF-gas percentages to ensure that the reported percentages do not establish a pattern of deviating from the historical norms of 1% for SWG and 3% for SPPC.
New Hampshire	Commission Staff continually compares current reported actual LAUF-gas volumetric data in cost of gas reconciliations and in PHMSA reports to actual LAUF-gas numbers in prior period reports. If the numbers reflect anomalies to historical numbers, Staff will follow up with discovery questions directed to the utility.
New Jersey	The Board monitors LAUF gas through BGSS filings.
New Mexico	Only to the extent it is represented in the PGA factor filings. If the gas purchased/gas sold ratio should appear to be excessive, the Commission could investigate the matter.
North Carolina	LAUF gas is reviewed during the annual review. The Public Staff reviews historical data to see if LAUF gas is within a reasonable range. Pipeline Safety monitors LAUF gas. If LAUF gas is 2% or higher, Pipeline Safety considers it to be a red flag and investigates.

North Dakota	No
Ohio	No
Oklahoma	This is a consideration when approving a utility for recovery of LAUF gas and setting the Safe Harbor.
Pennsylvania	Yes, this information is used by multiple bureaus for different purposes. For instance, this information would be used during PGC or GCR cases to aid in development of gas cost rates. This information would also be used for compliance/investigatory action by Gas Safety or the Bureau of Audits.
South Carolina	No
South Dakota	Rarely
Tennessee	No
Texas	As previously mentioned, the Pipeline Safety Division monitors the LAUF gas of distribution systems during scheduled inspections. If the LAUF gas is over 10%, the inspectors are directed to investigate further and attempt to find out the reasons for the elevated LAUF. Utilities not able to explain reasons for the high values are cited an alleged violation and Commission inspectors thereafter monitor progress to reduce the LAUF-gas level.
Utah	The Commission does not monitor LAUF gas but the Division of Public Utilities might.
Vermont	No
Virginia	The Commission Staff reviews LAUF gas in the context of PGA reconciliation hearings.
Washington	No
Wisconsin	Our Commission does monitor LAUF gas over time; it uses this information to identify LAUF trends.

Wyoming	The monitoring of LAUF gas is a responsibility of the team of analysts and engineers. It typically is raised as a point of discussion in the context of submitted filings; if deemed worthy of investigation, it is typically pursued in the form of information requests and dialog between the analyst and utility, potentially resulting in a discussion of the matter with Commissioners when the Docket is presented for consideration. Most recently, LAUF gas has been a sub-issue within the SourceGas show cause investigation (Docket 30022-191-GI-12, Record 13200) and subsequent reviews of its financial reporting resulting from the findings in that case.

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

Scott Madden Report on UFG, page 28

Preamble:

The Madden Report states: *"Meters can fail over time leading to differences between actual and metered volumes. These differences can represent a source of UFG. In some cases, meters may run "fast"; i.e., metered volumes are more than actual volumes. In other cases, meters may run "slow"; i.e., metered volumes are less than actual volumes. Fast meters tend to decrease UFG, while slow meters tend to increase UFG."*

Question:

Please provide the company's opinion on whether, "over time", meters run "fast" or "slow".

Response

The change of meter accuracy over time is specific for each meter. In Enbridge Gas's opinion, on average, diaphragm meters tend to run "fast", rotary meters are flat (neither "fast" nor "slow"), dual rotor turbine meters are flat, single rotor turbine meters tend to run "fast", and ultrasonic meters are flat.

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

Scott Madden Report on UFG, page 33

Preamble:

The Madden Report states: *"In Connecticut, the utilities require the worst performing meter classifications to undergo a greater number of periodic tests in subsequent years. Utilities have addressed the meter accuracy component by establishing a meter test program the results of which are reported to the Commission on an annual basis."*

Question:

What does EGI take from the above observation as applied to its franchise?

Response

In Canada, the frequency of mandatory meter reverification (Measurement Canada's term for periodic test) is established by Measurement Canada for each meter type (or meter classification) based on performance of meter type. This frequency of reverification is specified in Measurement Canada's bulletin G-18 (e.g., turbine meters should be reverified every 4 years and rotary meters should be reverified every 16 years). Residential diaphragm meters are reverified by testing a group of meters from each lot of meters installed in the field and the performance of the meters under test determines the date of the subsequent testing.

There are no federal regulations for meter reverification in the United States. Therefore, each state establishes its own rules and the Connecticut requirement is one of the ways to ensure the accuracy of the installed meters is adequate.

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

Scott Madden Report on UFG, page 33

Preamble:

The Madden Report states: *Review and update Supercompressibility parameters to more accurately measure and record volumes at elevated pressures. There is an ongoing effort to standardize this procedure across the legacy Companies. The update of Supercompressibility parameters is expected starting March 2020.*

Question:

Please specify if the EGD rate zone is using elevation factors.

a) If so, when were they implemented?

b) What aspects of the elevation protocol require more accuracy?

Response

a) Yes, the EGD rate zone is using elevation factors. Elevation zones were entered into the customer information system when it was implemented in 1998.

b) Elevation factors are established based on actual elevations of the measurement equipment. Elevation factors meet the atmospheric pressure calculations specified in section 37 of the Electricity and Gas Inspection Regulations and do not require more accuracy.

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

Scott Madden Report on UFG, page 33

Preamble:

The Madden Report states: *Review and update Supercompressibility parameters to more accurately measure and record volumes at elevated pressures. There is an ongoing effort to standardize this procedure across the legacy Companies. The update of Supercompressibility parameters is expected starting March 2020.*

Question:

When did EGD first recognize the impact of Supercompressibility at moderate pressures?

Response

The impact of Supercompressibility at moderate pressures was first recognized in summer of 2019.

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

ScottMadden Report on UFG, page 34-35

Preamble:

The Madden Report states*: "Gate station meter variations represent a potential source of UFG if there are differences between actual and metered volumes. Gate station meter variations have been recognized by gas utilities and the legacy Companies as a potential source of UFG and have implemented a number of practices and initiatives to monitor and manage gate station meter variations."*

We understand that TransCanada experienced some significant challenges in applying chromatographic readings to delivered gas from October 2018 to January 2019.

Question:

Please explain in layman's term how the components of the gas stream impact energy content of the gas stream.

Response

The majority of natural gas is made up of methane, but other components with a higher energy content than methane (such as ethane or propane) or no energy at all (such as nitrogen or carbon dioxide) impact the overall energy content of the gas stream as the mix of components varies.

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

ScottMadden Report on UFG, page 34-35

Preamble:

The Madden Report states: *"Gate station meter variations represent a potential source of UFG if there are differences between actual and metered volumes. Gate station meter variations have been recognized by gas utilities and the legacy Companies as a potential source of UFG and have implemented a number of practices and initiatives to monitor and manage gate station meter variations."*

We understand that TransCanada experienced some significant challenges in applying chromatographic readings to delivered gas from October 2018 to January 2019.

Question:

Please provide a summary of the issue with TransCanada's chromatographic readings from EGI's perspective?

Response

TC Energy has a number of gas chromatographs, but not one at every gate station / tap. Enbridge Gas understands that TC Energy uses an algorithm to determine heat values / gas components at gate stations without chromatographs. During the time in question, there was an issue with the gas chromatograph at Victoria Square which is used to determine heat values / energy components for GTA to Eastern Ontario (it was reporting incorrectly). In these circumstances, TC Energy would normally reassign to the gas chromatograph at North Bay, but it was under maintenance, so the gas chromatograph at Spruce was used. The timing was bad, as the gas flow in winter was switching from a western source to gas coming from Parkway with a higher heat content. Enbridge Gas understands that TC Energy had to make adjustments (primarily to the energy quantities) to all gate stations affected by this.

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

Scott Madden Report on UFG, page 34-35

Preamble:

The Madden Report states: *"Gate station meter variations represent a potential source of UFG if there are differences between actual and metered volumes. Gate station meter variations have been recognized by gas utilities and the legacy Companies as a potential source of UFG and have implemented a number of practices and initiatives to monitor and manage gate station meter variations."*

We understand that TransCanada experienced some significant challenges in applying chromatographic readings to delivered gas from October 2018 to January 2019.

Question:

In an Excel file, for 2016 to 2018, please provide:

a) the daily volumetric reading of gas transferred from TCE to EGI at Victoria Square Gate station (in 000's of cubic meters)

b) the daily Heat Content applied by TCE to determine the energy transferred ($GJ/1000m^3$)

c) the resulting energy transfer determined

d) the daily Heat Content values measured at Parkway by Union/EGI ($GJ/1000m^3$)

e) the produce of the daily volumetric reading at Victoria Square from a) and the daily Heat Content values in d)

Response

a) to e) Please see Attachment 1.

GasDay	Egy	Vol	HV	Park East HV	Calc using Park East HV
	GJ	E3M³	MJ/M³	MJ/M³	GJ
1/1/2016	324441.5436	8337.1961	38.9149	38.9829	325008.0819
1/2/2016	302574.0444	7766.9913	38.9564	39.0185	303056.3513
1/3/2016	356099.6409	9147.0679	38.9305	39.0070	356799.6770
1/4/2016	363790.2589	9351.4162	38.9022	38.9523	364259.1679
1/5/2016	334726.4502	8608.5146	38.8832	38.9303	335132.0567
1/6/2016	350103.2954	9021.2704	38.8086	38.8632	350595.4354
1/7/2016	319694.9954	8232.6775	38.8324	38.8765	320057.6877
1/8/2016	258966.4332	6669.4689	38.8286	38.8131	258862.7629
1/9/2016	143989.2596	3720.2405	38.7043	38.7525	144168.6217
1/10/2016	391924.2559	10110.0061	38.7660	38.9095	393375.2804
1/11/2016	330585.4203	8485.7068	38.9579	39.0086	331015.5404
1/12/2016	417703.9971	10735.5232	38.9086	38.9608	418264.5707
1/13/2016	387179.4792	9937.0670	38.9632	39.0147	387691.6863
1/14/2016	284233.3941	7309.6468	38.8847	38.9200	284491.4538
1/15/2016	255224.4341	6562.1646	38.8933	38.9822	255807.6136
1/16/2016	293031.6486	7533.3907	38.8977	38.9297	293272.6380
1/17/2016	418253.6257	10769.5558	38.8367	38.8933	418863.5638
1/18/2016	374929.3590	9645.0285	38.8728	38.9217	375400.9044
1/19/2016	436812.1478	11245.4660	38.8434	38.8926	437365.4090
1/20/2016	444796.8843	11451.6005	38.8415	38.8936	445393.9696
1/21/2016	370986.9427	9550.2443	38.8458	38.8969	371474.8991
1/22/2016	318683.0051	8189.0647	38.9157	38.9718	319142.5901
1/23/2016	325595.9690	8362.3328	38.9360	38.9927	326069.9343
1/24/2016	251982.1610	6470.0097	38.9462	38.9966	252308.3795
1/25/2016	291199.8345	7484.1682	38.9088	38.9687	291648.3046
1/26/2016	289346.9559	7431.5009	38.9352	38.9841	289710.3727
1/27/2016	227145.0331	5836.6439	38.9171	38.9897	227568.9935
1/28/2016	324148.3254	8318.2261	38.9684	39.0220	324593.8204
1/29/2016	315072.4963	8072.7479	39.0292	39.0745	315438.5873
1/30/2016	188465.5653	4848.1810	38.8735	38.8949	188569.5157
1/31/2016	141953.0785	3648.1700	38.9108	39.0247	142368.7386
2/1/2016	253541.0698	6523.4756	38.8659	38.9472	254071.1087
2/2/2016	273020.3882	7014.2722	38.9236	39.0127	273645.6986
2/3/2016	153873.1657	3949.5229	38.9599	39.1754	154724.1390
2/4/2016	216020.2741	5656.6733	38.1886	39.1583	221505.7103
2/5/2016	215494.0945	5560.1242	38.7571	38.8896	216231.0062
2/6/2016	190303.8673	4897.1319	38.8603	38.9278	190634.5716
2/7/2016	206821.9545	5319.5900	38.8793	38.9344	207115.0437
2/8/2016	195609.5841	5019.1738	38.9725	39.0344	195920.4366
2/9/2016	231455.7942	5954.3670	38.8716	38.9346	231830.8955
2/10/2016	310242.5646	7991.4062	38.8220	38.8690	310617.9657
2/11/2016	284945.8922	7335.4647	38.8450	38.8914	285286.4918
2/12/2016	434006.5742	11178.3650	38.8256	38.8742	434549.9959
2/13/2016	383443.1165	9873.9271	38.8339	38.8871	383968.3917
2/14/2016	279632.7105	7198.3793	38.8466	38.8975	279998.9604

GasDay	Egy GJ	Vol E3M³	HV MJ/M³	Park East HV MJ/M³	Calc using Park East HV GJ
2/15/2016	321308.5414	8262.4489	38.8878	38.9411	321748.8507
2/16/2016	348361.1157	8963.7941	38.8631	38.9137	348814.3932
2/17/2016	340562.9313	8752.8768	38.9087	38.9619	341028.7086
2/18/2016	314253.5836	8078.2810	38.9010	38.9509	314656.3158
2/19/2016	217434.3100	5593.5728	38.8722	38.9283	217748.2817
2/20/2016	116146.7311	2986.5049	38.8905	39.0235	116543.8741
2/21/2016	169167.4243	4322.1193	39.1399	39.1662	169280.9901
2/22/2016	263777.0539	6811.8568	38.7232	38.7678	264080.7013
2/23/2016	245874.9050	6347.7343	38.7343	38.7908	246233.6923
2/24/2016	279146.2667	7235.8407	38.5783	38.7665	280508.2184
2/25/2016	303868.6928	7866.9662	38.6259	38.7414	304777.2833
2/26/2016	257244.2017	6654.7892	38.6555	38.7134	257629.5153
2/27/2016	171941.2302	4456.4074	38.5829	38.7474	172674.1991
2/28/2016	150591.3232	3919.6697	38.4194	38.7213	151774.7076
2/29/2016	227894.7642	5877.1999	38.7761	38.8955	228596.6288
3/1/2016	332151.4692	8536.5927	38.9091	38.9244	332281.7469
3/2/2016	374023.7032	9637.2462	38.8102	38.8560	374464.8376
3/3/2016	459661.9325	11843.2266	38.8122	38.8607	460236.0767
3/4/2016	250159.8172	6446.1988	38.8073	38.8494	250430.9553
3/5/2016	314439.3976	8108.6243	38.7784	38.8087	314685.1659
3/6/2016	219504.1958	5677.6881	38.6608	38.7047	219753.2158
3/7/2016	147265.9118	3814.1845	38.6101	38.6406	147382.3772
3/8/2016	99037.5643	2558.0216	38.7165	38.6544	98878.7902
3/9/2016	89344.8950	2310.0576	38.6765	38.6954	89388.6013
3/10/2016	135320.4148	3535.2646	38.2773	38.3588	135608.5085
3/11/2016	135813.7200	3560.0008	38.1499	38.2868	136301.0389
3/12/2016	165172.5546	4325.3251	38.1873	38.2018	165235.2026
3/13/2016	163003.6627	4271.6233	38.1597	38.2265	163289.2070
3/14/2016	166412.4818	4362.3442	38.1475	38.2689	166942.1158
3/15/2016	124100.8560	3249.2179	38.1941	38.3080	124471.0374
3/16/2016	101993.7201	2670.9129	38.1868	38.2182	102077.4847
3/17/2016	179505.9541	4698.9825	38.2010	38.4147	180510.0030
3/18/2016	221856.4244	5736.5392	38.6743	38.8709	222984.4426
3/19/2016	160448.7056	4123.3774	38.9120	38.9641	160663.6886
3/20/2016	194435.7223	5002.0599	38.8711	38.9223	194691.6757
3/21/2016	241857.9879	6220.8626	38.8785	38.9370	242221.7273
3/22/2016	193655.7306	4986.1554	38.8387	38.8764	193843.7710
3/23/2016	181616.7317	4706.1547	38.5913	38.8634	182897.1743
3/24/2016	241560.2446	6289.4109	38.4075	38.8504	244346.1297
3/25/2016	187979.0788	4909.1866	38.2913	38.8640	190790.6284
3/26/2016	166294.7648	4344.8977	38.2736	38.8604	168844.4634
3/27/2016	136871.6351	3573.7155	38.2995	38.5570	137791.7481
3/28/2016	175042.0429	4567.5558	38.3229	38.5046	175871.9079
3/29/2016	170516.3348	4401.7738	38.7381	38.9179	171307.7922
3/30/2016	148000.1326	3824.2797	38.7001	38.9246	148858.5584

GasDay	Egy GJ	Vol E3M³	HV MJ/M³	Park East HV MJ/M³	Calc using Park East HV GJ
3/31/2016	148306.7465	3861.1147	38.4103	38.6512	149236.7169
4/1/2016	147829.5103	3858.6799	38.3109	38.3409	147945.2599
4/2/2016	175275.6361	4534.1339	38.6569	38.8606	176199.1625
4/3/2016	231110.7558	5938.1169	38.9199	38.9675	231393.5687
4/4/2016	247658.5870	6341.1630	39.0557	39.1164	248043.4683
4/5/2016	232282.2302	5951.7448	39.0276	39.0735	232555.5004
4/6/2016	229224.2601	5875.7302	39.0120	39.0661	229541.8645
4/7/2016	271666.5089	6969.3457	38.9802	39.0294	272009.3818
4/8/2016	259267.3559	6648.9401	38.9938	39.0472	259622.4931
4/9/2016	190077.2057	4874.1063	38.9973	39.0061	190119.8761
4/10/2016	137356.0799	3532.3445	38.8852	38.9253	137497.5708
4/11/2016	167415.0000	4314.9191	38.7991	38.8444	167610.4443
4/12/2016	213264.9560	5492.4452	38.8288	38.8868	213583.6172
4/13/2016	241336.6871	6211.4841	38.8533	38.8890	241558.4041
4/14/2016	215630.8279	5554.9730	38.8176	38.8801	215977.9065
4/15/2016	231166.4842	5948.7677	38.8596	38.8300	230990.6506
4/16/2016	196500.3812	5084.0456	38.6504	38.5813	196149.0873
4/17/2016	168814.2312	4368.1493	38.6466	38.5671	168466.8524
4/18/2016	174430.4840	4528.3915	38.5193	38.5671	174646.9270
4/19/2016	175774.1343	4569.1100	38.4701	38.5671	176217.3238
4/20/2016	214541.6144	5594.1988	38.3507	38.5671	215752.0234
4/21/2016	192327.2174	4980.5790	38.6154	38.5671	192086.4891
4/22/2016	202730.4313	5299.3963	38.2554	38.5563	204325.1139
4/23/2016	239915.1133	6295.0685	38.1116	38.5593	242733.4356
4/24/2016	243412.1033	6412.5185	37.9589	38.5593	247262.2250
4/25/2016	230419.1216	6037.3073	38.1659	38.4911	232382.5982
4/26/2016	284617.3458	7389.6209	38.5158	38.6079	285297.7451
4/27/2016	272113.7665	7045.6171	38.6217	38.7139	272763.3174
4/28/2016	283901.3996	7317.8589	38.7957	38.8079	283990.7352
4/29/2016	232265.3124	6018.0279	38.5949	38.6297	232474.6128
4/30/2016	167034.9148	4333.9875	38.5407	38.5819	167213.4708
5/1/2016	205036.1328	5325.6647	38.4996	38.5873	205503.0226
5/2/2016	225155.5069	5826.1208	38.6459	38.6112	224953.5135
5/3/2016	175467.9958	4560.8332	38.4728	38.5186	175676.9080
5/4/2016	139737.4706	3628.0232	38.5161	38.4700	139570.0519
5/5/2016	189915.4254	4971.1784	38.2033	38.4863	191322.2614
5/6/2016	160158.5984	4201.2708	38.1215	38.2220	160580.9715
5/7/2016	168652.0920	4417.7366	38.1761	38.0257	167987.5248
5/8/2016	150506.0790	3941.9493	38.1806	38.4000	151370.8524
5/9/2016	168428.3693	4403.8920	38.2453	38.3995	169107.2512
5/10/2016	173399.2049	4585.5582	37.8142	38.3996	176083.6017
5/11/2016	145557.3800	3846.3810	37.8427	38.3891	147659.1045
5/12/2016	147531.4798	3902.6659	37.8027	37.8692	147790.8338
5/13/2016	166045.6281	4387.9560	37.8412	37.8059	165890.6275
5/14/2016	189440.1099	5023.7280	37.7091	37.7568	189679.8934

GasDay	Egy GJ	Vol E3M³	HV MJ/M³	Park East HV MJ/M³	Calc using Park East HV GJ
5/15/2016	239422.0439	6259.6049	38.2487	38.0082	237916.3135
5/16/2016	217440.0751	5637.5708	38.5698	38.4141	216562.2100
5/17/2016	169033.3634	4374.9616	38.6365	38.4184	168079.0255
5/18/2016	183638.7778	4748.6868	38.6715	38.6823	183690.1268
5/19/2016	165481.6325	4274.5828	38.7129	38.7213	165517.4022
5/20/2016	149972.0794	3883.7983	38.6148	38.6950	150283.5748
5/21/2016	139987.1539	3631.3899	38.5492	38.4461	139612.7787
5/22/2016	142051.5156	3705.4611	38.3357	38.0989	141173.9913
5/23/2016	131504.5361	3453.1834	38.0821	37.9889	131182.6390
5/24/2016	135379.0130	3560.1741	38.0260	38.0836	135584.2453
5/25/2016	183908.9837	4832.9069	38.0535	38.1277	184267.6246
5/26/2016	178895.5959	4705.3478	38.0196	38.0984	179266.2211
5/27/2016	168610.8421	4454.7057	37.8501	38.0257	169393.3036
5/28/2016	166710.8377	4420.3012	37.7148	37.8748	167418.0240
5/29/2016	177066.9050	4671.9500	37.9000	37.9283	177199.1212
5/30/2016	180927.7549	4762.5100	37.9900	38.0165	181053.9614
5/31/2016	176932.8745	4679.2657	37.8121	38.0544	178066.6474
6/1/2016	151671.0911	4003.8491	37.8813	37.9315	151872.0038
6/2/2016	162993.8440	4298.6126	37.9178	37.9612	163180.4910
6/3/2016	142214.4227	3742.9203	37.9956	38.0734	142505.7035
6/4/2016	118887.4543	3126.3362	38.0277	38.0695	119018.0567
6/5/2016	116445.4178	3061.4348	38.0362	38.1319	116738.3242
6/6/2016	116540.8485	3049.0883	38.2215	38.3005	116781.6045
6/7/2016	135036.8448	3531.1097	38.2420	38.2994	135239.3840
6/8/2016	144672.9396	3799.2793	38.0790	38.1739	145033.3069
6/9/2016	145522.9746	3825.7353	38.0379	38.0742	145661.8117
6/10/2016	135739.6349	3564.6292	38.0796	38.2290	136272.2101
6/11/2016	110722.0619	2900.1080	38.1786	38.5690	111854.2643
6/12/2016	112329.4860	2932.3793	38.3066	38.6076	113212.1274
6/13/2016	118670.1291	3090.3685	38.4000	38.4023	118677.2589
6/14/2016	133212.0761	3466.0159	38.4338	38.4446	133249.5960
6/15/2016	116865.0330	3013.3141	38.7829	38.8039	116928.3385
6/16/2016	131964.4349	3367.1010	39.1923	39.2410	132128.4097
6/17/2016	118528.7240	3032.9266	39.0806	39.2178	118944.7087
6/18/2016	101546.0042	2594.2217	39.1431	39.1969	101685.4496
6/19/2016	151097.4523	3897.3865	38.7689	38.7683	151095.0472
6/20/2016	145206.1482	3829.5347	37.9174	38.0944	145883.8253
6/21/2016	149394.3680	3960.9216	37.7171	38.7140	153343.1189
6/22/2016	147363.9102	3907.9533	37.7087	38.2157	149345.1695
6/23/2016	124731.0594	3306.7525	37.7201	37.7583	124857.3525
6/24/2016	143530.0800	3805.1467	37.7200	37.7702	143721.1516
6/25/2016	129863.4889	3434.7859	37.8083	37.7418	129635.0042
6/26/2016	147842.9352	3920.5554	37.7097	37.7576	148030.7620
6/27/2016	153318.3531	4072.8837	37.6437	37.6958	153530.6107
6/28/2016	143474.3107	3806.7970	37.6890	37.7001	143516.6267

GasDay	Egy	Vol	HV	Park East HV	Calc using Park East HV
	GJ	E3M³	MJ/M³	MJ/M³	GJ
6/29/2016	153688.7623	4068.6881	37.7735	37.7577	153624.3045
6/30/2016	127890.1535	3310.9089	38.6269	38.4876	127428.9369
7/1/2016	155858.1027	4070.5368	38.2893	38.1072	155116.7590
7/2/2016	97206.4173	2571.8347	37.7965	37.8991	97470.2212
7/3/2016	117917.1701	3109.0382	37.9272	37.8097	117551.8009
7/4/2016	144507.7610	3812.1952	37.9067	38.0214	144944.9969
7/5/2016	169108.7909	4460.9292	37.9089	37.9413	169253.4517
7/6/2016	164317.7502	4319.1536	38.0440	38.2763	165321.2196
7/7/2016	148171.4300	3864.9697	38.3370	38.3973	148404.4019
7/8/2016	145749.7788	3802.3741	38.3313	38.3855	145956.0318
7/9/2016	104275.2063	2738.2487	38.0810	38.0226	104115.3347
7/10/2016	129310.5035	3426.9702	37.7332	37.7399	129333.5142
7/11/2016	148718.6997	3937.6257	37.7686	37.7700	148724.1210
7/12/2016	134113.2401	3556.1890	37.7126	37.8165	134482.6211
7/13/2016	130607.3895	3466.5341	37.6766	37.7954	131019.0435
7/14/2016	120700.3670	3201.3310	37.7032	37.8745	121248.8097
7/15/2016	113941.3654	3023.6613	37.6832	38.3830	116057.1912
7/16/2016	89124.4934	2365.6210	37.6749	37.8886	89630.0687
7/17/2016	131570.7326	3487.9291	37.7217	37.7709	131742.2222
7/18/2016	200756.0336	5325.9190	37.6942	37.8087	201366.0718
7/19/2016	191849.6902	5093.7492	37.6637	37.7927	192506.5343
7/20/2016	201058.7570	5329.4257	37.7262	37.7204	201028.0680
7/21/2016	216173.6332	5680.0369	38.0585	38.2659	217351.7229
7/22/2016	197558.7522	5214.1461	37.8890	38.3379	199899.4126
7/23/2016	196859.9717	5202.9659	37.8361	38.4026	199807.4191
7/24/2016	181431.0262	4759.3781	38.1207	38.4069	182792.9603
7/25/2016	197360.5898	5147.8125	38.3387	38.4038	197695.5631
7/26/2016	199528.8254	5213.4761	38.2717	38.4041	200218.8571
7/27/2016	210455.1425	5490.0851	38.3337	38.4039	210840.6776
7/28/2016	206607.3473	5389.9630	38.3319	38.3941	206942.7777
7/29/2016	148518.0137	3900.5953	38.0757	38.0458	148401.2693
7/30/2016	117925.6606	3114.5497	37.8628	37.7769	117658.0336
7/31/2016	107090.3920	2837.8212	37.7368	37.7707	107186.4917
8/1/2016	144105.1481	3822.8158	37.6961	37.7454	144293.7107
8/2/2016	187830.9886	4982.7613	37.6962	37.7460	188079.3080
8/3/2016	203042.3121	5370.7006	37.8056	37.7134	202547.3811
8/4/2016	176290.1270	4670.2125	37.7478	37.7607	176350.4932
8/5/2016	164448.9395	4352.3925	37.7836	37.8251	164629.6813
8/6/2016	166407.1143	4410.7030	37.7280	37.7859	166662.3842
8/7/2016	159343.2506	4225.9381	37.7060	37.7526	159540.1522
8/8/2016	188725.5466	4988.8927	37.8291	37.8062	188611.0750
8/9/2016	239549.3947	6331.9605	37.8318	37.8309	239543.7656
8/10/2016	249402.3217	6557.6935	38.0320	38.1976	250488.1544
8/11/2016	205765.0583	5365.0666	38.3527	38.4838	206468.1508
8/12/2016	199035.6485	5154.0375	38.6174	38.6946	199433.4191

GasDay	Egy GJ	Vol E3M³	HV MJ/M³	Park East HV MJ/M³	Calc using Park East HV GJ
8/13/2016	157268.5873	4075.6602	38.5873	38.4858	156855.0443
8/14/2016	173130.0890	4511.5893	38.3745	38.4147	173311.3479
8/15/2016	174771.1346	4557.3202	38.3495	38.4214	175098.6218
8/16/2016	181192.4499	4724.2025	38.3541	38.4086	181450.0049
8/17/2016	186675.3911	4871.3723	38.3209	38.4459	187284.2912
8/18/2016	182334.9226	4776.0860	38.1766	38.4551	183664.8649
8/19/2016	170359.2853	4466.3002	38.1433	38.4403	171685.9181
8/20/2016	140749.0191	3680.9321	38.2373	38.3374	141117.3652
8/21/2016	114600.7493	3031.5932	37.8022	37.8023	114601.1964
8/22/2016	154962.9002	4087.4642	37.9117	37.9419	155086.1560
8/23/2016	157143.5945	4159.7842	37.7769	37.8381	157398.3322
8/24/2016	212858.3868	5634.7734	37.7759	37.8267	213144.8823
8/25/2016	222685.0191	5896.1677	37.7678	37.8162	222970.6577
8/26/2016	220771.3959	5834.7976	37.8370	37.8367	220769.4867
8/27/2016	199710.0400	5291.3579	37.7427	37.8000	200013.3290
8/28/2016	245516.1084	6493.2217	37.8111	37.8437	245727.5348
8/29/2016	198883.1580	5262.4494	37.7929	37.9274	199591.0249
8/30/2016	179130.1688	4735.8948	37.8239	37.8520	179263.0883
8/31/2016	169279.0397	4459.2283	37.9615	37.8766	168900.4066
9/1/2016	133480.9251	3526.2761	37.8532	37.8689	133536.1987
9/2/2016	157319.3643	4161.9840	37.7991	37.8421	157498.2160
9/3/2016	128300.4760	3390.1882	37.8446	37.9081	128515.5932
9/4/2016	144658.8541	3827.1284	37.7983	37.8617	144901.5862
9/5/2016	143069.9975	3774.1505	37.9079	37.9801	143342.6127
9/6/2016	166423.3482	4398.1063	37.8398	37.8747	166576.9573
9/7/2016	179708.1005	4743.6818	37.8837	37.9767	180149.3825
9/8/2016	177050.0908	4650.7399	38.0692	38.2599	177936.8427
9/9/2016	164738.1849	4297.4758	38.3337	38.3988	165017.9136
9/10/2016	120940.8683	3173.2469	38.1127	38.2516	121381.7722
9/11/2016	112848.4459	2981.4094	37.8507	37.8624	112883.3156
9/12/2016	150970.1971	4002.4251	37.7197	37.7693	151168.7947
9/13/2016	154310.6461	4087.8983	37.7482	37.7925	154491.8957
9/14/2016	139811.4698	3710.9294	37.6756	37.7454	140070.5128
9/15/2016	135372.1921	3575.5316	37.8607	37.8381	135291.3239
9/16/2016	119991.8859	3174.6638	37.7967	37.8472	120152.1363
9/17/2016	119562.5401	3164.1274	37.7869	37.8961	119908.0891
9/18/2016	168517.6075	4458.3411	37.7983	37.8446	168724.1366
9/19/2016	172137.4141	4548.4393	37.8454	37.9529	172626.4604
9/20/2016	182870.9045	4835.7674	37.8163	37.9766	183646.0059
9/21/2016	149894.8123	3963.7153	37.8167	37.9938	150596.6048
9/22/2016	172888.1822	4571.8812	37.8155	37.9295	173409.1672
9/23/2016	151771.1913	4006.0976	37.8850	37.9612	152076.2741
9/24/2016	152365.8223	4030.5965	37.8023	37.8393	152514.9507
9/25/2016	145637.0003	3846.5989	37.8612	37.9290	145897.6485
9/26/2016	151456.5735	4004.9555	37.8173	37.8297	151506.2666

GasDay	Egy GJ	Vol E3M³	HV MJ/M³	Park East HV MJ/M³	Calc using Park East HV GJ
9/27/2016	139217.9690	3680.3109	37.8278	37.8892	139444.0373
9/28/2016	135645.9162	3599.2933	37.6868	37.7258	135786.2192
9/29/2016	143073.0463	3787.5176	37.7749	37.8293	143279.1399
9/30/2016	146079.7863	3868.1680	37.7646	37.7574	146051.9653
10/1/2016	140029.0343	3709.8861	37.7448	37.8496	140417.7057
10/2/2016	138892.7403	3676.7773	37.7757	37.9003	139350.9635
10/3/2016	147849.7565	3901.7201	37.8935	38.0684	148532.2403
10/4/2016	150931.7016	3996.7023	37.7641	37.7707	150958.2417
10/5/2016	143557.1624	3793.3934	37.8440	37.8519	143587.1457
10/6/2016	135629.3924	3584.5967	37.8367	37.8429	135651.5341
10/7/2016	125683.1503	3319.9286	37.8572	38.0622	126363.7845
10/8/2016	125318.8114	3312.4425	37.8328	37.9282	125634.9797
10/9/2016	182690.0171	4811.6789	37.9680	38.0319	182997.2919
10/10/2016	183148.8963	4838.3836	37.8533	37.9038	183393.1258
10/11/2016	186473.2723	4927.2978	37.8449	37.9115	186801.2505
10/12/2016	156578.3689	4142.3207	37.7997	37.7876	156528.3558
10/13/2016	207295.9133	5487.4662	37.7763	37.8241	207558.4688
10/14/2016	180542.3156	4781.3123	37.7600	37.7972	180720.2158
10/15/2016	122873.0582	3252.3520	37.7798	37.8627	123142.8262
10/16/2016	125515.1671	3322.3763	37.7787	37.8447	125734.3340
10/17/2016	142683.2684	3772.2048	37.8249	37.8894	142926.5756
10/18/2016	143710.3900	3787.5175	37.9432	37.9612	143778.7077
10/19/2016	165284.5369	4359.0024	37.9180	37.9826	165566.2457
10/20/2016	176948.9267	4661.5422	37.9593	37.9945	177112.9659
10/21/2016	244001.3824	6395.7002	38.1508	38.1206	243807.9271
10/22/2016	190252.0384	4999.4547	38.0546	38.1849	190903.6759
10/23/2016	161721.3371	4248.3980	38.0664	38.1089	161901.7734
10/24/2016	204271.9584	5340.8832	38.2469	38.2745	204419.6333
10/25/2016	223048.6453	5796.0715	38.4827	38.6418	223970.6363
10/26/2016	207711.9066	5336.1093	38.9257	38.9620	207905.4905
10/27/2016	230541.0666	5964.6726	38.6511	38.7316	231021.3140
10/28/2016	164308.6480	4247.1260	38.6870	38.7075	164395.6288
10/29/2016	176367.1067	4569.6657	38.5952	38.6856	176780.2588
10/30/2016	274361.1472	7117.9757	38.5448	38.5606	274473.4133
10/31/2016	258334.4601	6700.5767	38.5541	38.6773	259160.2151
11/1/2016	164537.9442	4266.3079	38.5668	38.5616	164515.6591
11/2/2016	187164.2983	4908.5440	38.1303	38.4438	188703.0846
11/3/2016	251400.7780	6553.2159	38.3630	38.5041	252325.6819
11/4/2016	242879.8061	6332.5669	38.3541	38.6374	244673.9211
11/5/2016	196171.6913	5131.7834	38.2268	38.5445	197802.0266
11/6/2016	235852.4130	6172.9581	38.2074	38.5219	237794.0762
11/7/2016	234659.6844	6129.4409	38.2840	38.6366	236820.7567
11/8/2016	224255.2461	5872.3520	38.1883	38.4943	226052.0789
11/9/2016	299827.0812	7808.1612	38.3992	38.5524	301023.3532
11/10/2016	202483.5541	5264.4400	38.4625	38.4982	202671.4640

GasDay	Egy GJ	Vol E3M³	HV MJ/M³	Park East HV MJ/M³	Calc using Park East HV GJ
11/11/2016	311944.4760	8104.6642	38.4895	38.5872	312736.2984
11/12/2016	242713.3246	6291.0475	38.5807	38.6433	243106.8347
11/13/2016	231627.1347	6049.1745	38.2907	38.5549	233225.3181
11/14/2016	261954.5961	6842.7051	38.2823	38.5285	263639.1627
11/15/2016	163864.6557	4274.7305	38.3333	38.5106	164622.4350
11/16/2016	151421.6939	3975.4200	38.0895	38.5445	153230.5756
11/17/2016	145977.5951	3825.4989	38.1591	38.5372	147424.0143
11/18/2016	165767.6660	4350.2031	38.1057	38.6006	167920.4515
11/19/2016	281385.4267	7304.4238	38.5226	38.6247	282131.1791
11/20/2016	349646.8754	9039.2259	38.6811	38.7741	350487.8497
11/21/2016	292717.4238	7553.6463	38.7518	38.8089	293148.7038
11/22/2016	365106.9594	9413.2971	38.7863	38.7999	365234.9850
11/23/2016	331974.4083	8545.3604	38.8485	38.8041	331595.0199
11/24/2016	268113.9904	6890.9481	38.9081	38.9209	268201.9031
11/25/2016	205654.6617	5287.7738	38.8925	38.9705	206067.1884
11/26/2016	217363.4912	5588.5312	38.8946	39.0134	218027.6032
11/27/2016	224697.4859	5787.3443	38.8257	39.0249	225850.5344
11/28/2016	235486.7525	6045.9325	38.9496	39.0149	235881.4521
11/29/2016	232387.1391	5984.1079	38.8340	39.0121	233452.6173
11/30/2016	258249.2104	6646.7492	38.8535	39.0088	259281.7118
12/1/2016	292755.2020	7531.6702	38.8699	39.0099	293809.7022
12/2/2016	171531.3925	4407.6605	38.9167	39.0098	171941.9529
12/3/2016	218216.0403	5610.8749	38.8916	39.0096	218877.9850
12/4/2016	205923.5324	5300.3047	38.8513	39.0092	206760.6445
12/5/2016	270574.8462	6974.7353	38.7936	39.0107	272089.3068
12/6/2016	258451.4364	6661.9822	38.7950	39.0106	259887.9216
12/7/2016	295634.5171	7610.5412	38.8454	39.0117	296900.1494
12/8/2016	311180.5977	8002.6567	38.8847	39.0110	312191.6413
12/9/2016	279447.9722	7183.4669	38.9015	39.0093	280222.0167
12/10/2016	289183.9293	7444.5491	38.8451	39.0068	290388.0382
12/11/2016	242743.6688	6254.8858	38.8086	39.0040	243965.5670
12/12/2016	215939.4274	5567.4062	38.7864	39.0041	217151.6672
12/13/2016	212042.9548	5466.6043	38.7888	39.0012	213204.1294
12/14/2016	233289.1338	5992.1461	38.9325	39.0096	233751.2241
12/15/2016	233714.0826	5984.5790	39.0527	39.0572	233740.8977
12/16/2016	182260.3362	4687.3878	38.8831	38.9562	182602.8160
12/17/2016	173422.9794	4467.3002	38.8205	38.9356	173937.0120
12/18/2016	236168.5947	6077.6767	38.8584	38.9082	236471.4612
12/19/2016	155137.1403	3993.8853	38.8437	38.9345	155499.9253
12/20/2016	104942.6082	2698.2696	38.8926	38.9323	105049.8429
12/21/2016	191949.2032	4939.5616	38.8596	38.9331	192312.4442
12/22/2016	116986.4153	3011.9227	38.8411	38.9338	117265.5955
12/23/2016	65388.4967	1683.2157	38.8474	38.9346	65535.3319
12/24/2016	54994.0516	1417.0052	38.8101	38.9367	55173.5054
12/25/2016	70729.5189	1819.7501	38.8677	38.9364	70854.5168

GasDay	Egy GJ	Vol E3M³	HV MJ/M³	Park East HV MJ/M³	Calc using Park East HV GJ
12/26/2016	80876.2246	2082.3767	38.8384	38.9393	81086.2899
12/27/2016	198653.8720	5105.7435	38.9079	38.9398	198816.6319
12/28/2016	116692.7927	3001.4443	38.8789	38.9638	116947.6744
12/29/2016	135075.5400	3472.7166	38.8962	38.9622	135304.6772
12/30/2016	136030.2521	3499.8270	38.8677	38.9635	136365.5110
12/31/2016	41092.6773	1057.0379	38.8753	38.9642	41186.6368
1/1/2017	115770.7354	2974.0794	38.9266	38.9654	115886.1919
1/2/2017	123183.7878	3164.4872	38.9269	38.9659	123307.0920
1/3/2017	68703.4579	1763.8185	38.9515	38.9663	68729.4804
1/4/2017	193094.6447	4955.3396	38.9670	38.9707	193113.0533
1/5/2017	235580.6715	6059.1933	38.8799	38.9737	236149.1807
1/6/2017	188304.2924	4843.7601	38.8756	38.9788	188803.9548
1/7/2017	170332.8550	4381.4662	38.8758	38.9817	170797.0012
1/8/2017	95303.0392	2452.0741	38.8663	38.9843	95592.3910
1/9/2017	81731.1188	2103.3026	38.8585	38.9840	81995.1487
1/10/2017	49089.6751	1263.5585	38.8503	38.9841	49258.6923
1/11/2017	48813.1565	1256.6749	38.8431	38.9839	48990.0867
1/12/2017	121592.7884	3126.1823	38.8950	38.9847	121873.2779
1/13/2017	249430.1865	6416.1064	38.8756	38.9833	250121.0004
1/14/2017	200853.1970	5169.6950	38.8520	38.9819	201524.5331
1/15/2017	209394.8228	5389.2122	38.8544	38.9814	210079.0355
1/16/2017	100030.8867	2575.2684	38.8429	38.9812	100387.0527
1/17/2017	71601.7688	1842.9656	38.8514	38.9805	71839.7222
1/18/2017	71519.0583	1840.5058	38.8584	38.9812	71745.1254
1/19/2017	56887.9476	1464.6329	38.8411	38.9805	57092.1228
1/20/2017	74946.4407	1928.6583	38.8594	38.9796	75178.3300
1/21/2017	86257.8343	2220.5252	38.8457	38.9796	86555.1835
1/22/2017	90467.4011	2327.6112	38.8671	38.9802	90730.7496
1/23/2017	77238.8971	1985.1613	38.9081	38.9803	77382.1814
1/24/2017	73448.2252	1889.7379	38.8669	38.9804	73662.7380
1/25/2017	24545.1686	632.0651	38.8333	38.9795	24637.5819
1/26/2017	84792.3148	2181.6114	38.8668	38.9811	85041.6138
1/27/2017	112464.5146	2888.5009	38.9353	38.9811	112596.9428
1/28/2017	47896.6266	1225.8908	39.0709	38.9818	47787.4284
1/29/2017	174411.5832	4467.4339	39.0407	38.9830	174153.9744
1/30/2017	98098.2516	2514.5726	39.0119	38.9881	98038.4066
1/31/2017	97855.3050	2507.9354	39.0183	38.9940	97794.4314
2/1/2017	78634.7733	2014.3283	39.0377	39.0005	78559.8094
2/2/2017	85373.1822	2191.0838	38.9639	39.0014	85455.3352
2/3/2017	91949.8765	2366.4480	38.8557	39.0082	92310.8757
2/4/2017	72055.7559	1854.7675	38.8489	39.0144	72362.6404
2/5/2017	54021.2457	1391.4849	38.8227	39.0176	54292.4018
2/6/2017	56582.8598	1457.7948	38.8140	39.0213	56885.0466
2/7/2017	186864.4180	4814.9449	38.8093	39.0174	187866.6324
2/8/2017	200088.0908	5155.2024	38.8128	39.0198	201154.9666

GasDay	Egy GJ	Vol E3M³	HV MJ/M³	Park East HV MJ/M³	Calc using Park East HV GJ
2/9/2017	215710.6946	5554.5082	38.8352	39.0190	216731.3560
2/10/2017	107032.1669	2755.4282	38.8441	39.0162	107506.3392
2/11/2017	78815.8728	2032.9968	38.7683	39.0134	79314.1156
2/12/2017	90663.5539	2340.3345	38.7396	39.0125	91302.3010
2/13/2017	120497.9806	3111.6817	38.7244	39.0075	121378.9254
2/14/2017	79771.5033	2058.8471	38.7457	38.9931	80280.8318
2/15/2017	200662.1304	5177.9362	38.7533	38.9939	201907.9274
2/16/2017	210410.6010	5424.4774	38.7891	38.9825	211459.6901
2/17/2017	114167.5229	2936.4290	38.8797	38.9730	114441.4459
2/18/2017	110674.0143	2830.8998	39.0950	38.9363	110224.7629
2/19/2017	161288.6158	4157.6852	38.7929	38.9528	161953.4812
2/20/2017	187038.3123	4809.5689	38.8888	38.9623	187391.8681
2/21/2017	133259.2511	3416.6248	39.0032	38.9628	133121.2690
2/22/2017	178147.0001	4577.0168	38.9221	38.9604	178322.4061
2/23/2017	87028.3862	2246.3468	38.7422	38.9639	87526.4302
2/24/2017	64119.4678	1653.3530	38.7815	38.9603	64415.1278
2/25/2017	100957.1602	2598.2851	38.8553	38.9634	101238.0226
2/26/2017	121910.5259	3141.0220	38.8124	38.9572	122365.4232
2/27/2017	93685.3294	2413.0817	38.8239	38.9567	94005.7012
2/28/2017	50817.4904	1310.5481	38.7758	38.9127	50996.9633
3/1/2017	79684.0139	2057.5214	38.7282	38.9457	80131.6121
3/2/2017	215381.3246	5549.7761	38.8090	38.9302	216053.8920
3/3/2017	115432.9284	2974.7587	38.8041	38.9200	115777.6104
3/4/2017	129733.7643	3342.5811	38.8125	38.9101	130060.1647
3/5/2017	70404.1354	1816.5489	38.7571	38.9056	70673.9267
3/6/2017	137453.1734	3547.6126	38.7453	38.8959	137987.5858
3/7/2017	109148.4627	2810.8527	38.8311	38.8893	109312.0922
3/8/2017	188638.1886	4865.6338	38.7695	38.8950	189248.8256
3/9/2017	154035.8850	3965.1670	38.8473	38.9018	154252.1338
3/10/2017	149884.2203	3852.8626	38.9020	38.8956	149859.4041
3/11/2017	108625.3933	2794.9980	38.8642	38.8953	108712.2867
3/12/2017	199312.5711	5129.2800	38.8578	38.8949	199502.8326
3/13/2017	252838.6134	6504.7079	38.8701	38.8955	253003.8662
3/14/2017	222625.2234	5726.9516	38.8733	38.8973	222762.9532
3/15/2017	368360.7957	9481.8253	38.8491	38.9007	368849.6407
3/16/2017	253300.1896	6522.4515	38.8351	38.9036	253746.8444
3/17/2017	248426.9613	6406.3916	38.7780	38.9065	249250.2736
3/18/2017	185310.0749	4769.4675	38.8534	38.9083	185571.8714
3/19/2017	235075.4094	6055.2074	38.8220	38.9097	235606.3046
3/20/2017	249220.0157	6418.3953	38.8290	38.9146	249769.2865
3/21/2017	308718.9261	7958.7899	38.7897	38.9136	309705.1682
3/22/2017	247131.2500	6363.7858	38.8340	38.9152	247647.9990
3/23/2017	164585.3820	4240.5046	38.8127	38.9190	165036.2002
3/24/2017	215471.3878	5557.2441	38.7731	38.9222	216300.1663
3/25/2017	198440.6210	5112.7612	38.8128	38.9249	199013.7180

GasDay	Egy GJ	Vol E3M³	HV MJ/M³	Park East HV MJ/M³	Calc using Park East HV GJ
3/26/2017	131503.7429	3392.5326	38.7627	38.9217	132043.1369
3/27/2017	159683.1041	4117.1055	38.7853	38.9277	160269.4458
3/28/2017	199416.7993	5137.5253	38.8157	38.9229	199967.3848
3/29/2017	70004.4484	1801.7915	38.8527	38.9217	70128.7875
3/30/2017	58468.4235	1503.5676	38.8865	38.9217	58521.4057
3/31/2017	41455.0974	1065.6125	38.9026	38.9231	41476.9401
4/1/2017	55026.2354	1414.9962	38.8879	38.9245	55078.0196
4/2/2017	27185.6261	700.7161	38.7969	38.9270	27276.7774
4/3/2017	32970.3383	849.1238	38.8287	38.9230	33050.4462
4/4/2017	32266.5473	832.0392	38.7801	38.9233	32385.7104
4/5/2017	23335.3311	602.3697	38.7392	38.9253	23447.4203
4/6/2017	39577.1084	1021.9665	38.7264	38.9249	39779.9454
4/7/2017	53182.7084	1372.6850	38.7436	38.9293	53437.6656
4/8/2017	31189.0900	805.8107	38.7052	38.9269	31367.7108
4/9/2017	17876.0593	462.8909	38.6183	38.9265	18018.7208
4/10/2017	65728.0889	1699.2781	38.6800	38.9259	66145.9297
4/11/2017	43830.5502	1138.4307	38.5009	38.9242	44312.5028
4/12/2017	30508.3730	787.7481	38.7286	38.9253	30663.3320
4/13/2017	35282.1193	910.1120	38.7668	38.7455	35262.7432
4/14/2017	25420.4192	657.5560	38.6589	38.5814	25369.4310
4/15/2017	30455.5278	785.4334	38.7754	38.5038	30242.1710
4/16/2017	126781.6463	3293.3477	38.4963	38.4723	126702.6620
4/17/2017	105106.2288	2737.3955	38.3964	38.5942	105647.5887
4/18/2017	75272.6216	1943.8999	38.7225	38.7556	75337.0080
4/19/2017	20690.9524	535.1958	38.6605	38.7040	20714.2200
4/20/2017	18217.1496	472.3283	38.5688	38.5937	18228.8974
4/21/2017	15803.1719	409.8370	38.5597	38.6334	15833.3957
4/22/2017	23470.5567	608.8059	38.5518	38.5584	23474.5821
4/23/2017	57816.3721	1501.7047	38.5005	38.5557	57899.2764
4/24/2017	36462.5377	947.1302	38.4979	38.6101	36568.7900
4/25/2017	45230.2694	1173.1817	38.5535	38.5551	45232.1391
4/26/2017	22621.0134	584.1568	38.7242	38.9754	22767.7435
4/27/2017	109970.9771	2817.5554	39.0306	39.0940	110149.5115
4/28/2017	80202.6736	2046.7057	39.1862	39.2111	80253.5805
4/29/2017	45611.2404	1166.0417	39.1163	38.7707	45208.2532
4/30/2017	139295.2252	3600.6551	38.6861	38.6455	139149.1174
5/1/2017	51251.8078	1324.0983	38.7070	38.9711	51601.5674
5/2/2017	150288.6631	3884.6047	38.6883	38.5985	149939.9149
5/3/2017	94739.1353	2451.5579	38.6445	38.7495	94996.6438
5/4/2017	103567.6875	2680.0874	38.6434	38.7267	103790.9394
5/5/2017	112869.2986	2913.5292	38.7397	39.0124	113663.7650
5/6/2017	79871.7600	2052.9658	38.9055	39.0362	80139.9828
5/7/2017	150554.9042	3874.8642	38.8542	38.8982	150725.2432
5/8/2017	181638.5999	4684.9563	38.7706	38.7984	181768.8066
5/9/2017	201915.5784	5218.2092	38.6944	38.7471	202190.4752

GasDay	Egy GJ	Vol E3M³	HV MJ/M³	Park East HV MJ/M³	Calc using Park East HV GJ
5/10/2017	229097.4157	5918.4381	38.7091	38.8367	229852.6036
5/11/2017	180303.8677	4636.0991	38.8913	38.8784	180244.1158
5/12/2017	132040.3020	3402.9233	38.8020	38.8308	132138.2354
5/13/2017	99847.3227	2570.6952	38.8406	38.8130	99776.3936
5/14/2017	117888.5186	3063.9233	38.4763	38.4986	117956.7586
5/15/2017	91021.8781	2362.5701	38.5266	38.5822	91153.1536
5/16/2017	63671.3834	1652.0163	38.5416	38.5150	63627.4084
5/17/2017	140408.8043	3654.7242	38.4184	38.4759	140618.8047
5/18/2017	127001.4132	3309.0342	38.3802	38.4479	127225.4149
5/19/2017	185773.4689	4839.3273	38.3883	38.4562	186102.1401
5/20/2017	182058.4652	4742.4682	38.3890	38.3959	182091.3348
5/21/2017	158557.8398	4118.1082	38.5026	38.3994	158132.8848
5/22/2017	152342.1792	3960.1837	38.4685	38.4239	152165.7035
5/23/2017	178364.5633	4647.0928	38.3820	38.3968	178433.4922
5/24/2017	172746.8876	4517.0533	38.2433	38.3871	173396.5772
5/25/2017	231571.3736	6072.7168	38.1331	38.3659	232985.2436
5/26/2017	130378.5993	3423.0425	38.0885	38.3728	131351.7241
5/27/2017	108094.3158	2833.8951	38.1434	38.3815	108769.1444
5/28/2017	139567.6445	3657.0456	38.1640	38.3807	140359.9708
5/29/2017	144336.7695	3781.5810	38.1684	38.3747	145117.0349
5/30/2017	150137.2916	3925.1939	38.2496	38.3783	150642.2706
5/31/2017	169803.1684	4446.2031	38.1906	38.3809	170649.2750
6/1/2017	178674.7948	4669.0843	38.2676	38.3846	179220.9325
6/2/2017	146497.5810	3825.8550	38.2915	38.3817	146842.8173
6/3/2017	129126.1348	3375.9598	38.2487	38.3815	129574.4022
6/4/2017	129111.0225	3370.3241	38.3082	38.2520	128921.6359
6/5/2017	133499.5330	3474.9084	38.4181	38.2697	132983.7020
6/6/2017	154841.3506	4028.7452	38.4341	38.2795	154218.3526
6/7/2017	151030.1072	3934.3855	38.3872	38.2929	150659.0309
6/8/2017	145105.6228	3782.7167	38.3602	38.3016	144884.1016
6/9/2017	125665.6046	3274.0460	38.3824	38.2919	125369.4436
6/10/2017	105928.6503	2758.9939	38.3939	38.2866	105632.4947
6/11/2017	121340.3017	3160.4152	38.3938	38.2851	120996.8135
6/12/2017	147973.3663	3858.0375	38.3546	38.3718	148039.8441
6/13/2017	133753.3618	3488.7234	38.3388	38.3951	133949.8823
6/14/2017	114163.7560	2977.9172	38.3368	38.3911	114325.5174
6/15/2017	151950.5913	3963.3072	38.3393	38.3900	152151.3621
6/16/2017	129935.5928	3399.3003	38.2242	38.3904	130500.4977
6/17/2017	113392.5775	2976.6732	38.0937	38.3677	114208.1038
6/18/2017	95879.8698	2520.2252	38.0442	38.1158	96060.4011
6/19/2017	128341.3596	3373.4028	38.0451	38.1137	128572.8617
6/20/2017	71870.6969	1890.5881	38.0150	38.1175	72064.4938
6/21/2017	116836.1691	3061.5768	38.1621	38.3579	117435.6574
6/22/2017	103071.3422	2710.0633	38.0328	38.3206	103851.2504
6/23/2017	99035.8831	2603.7134	38.0364	38.0991	99199.1382

GasDay	Egy GJ	Vol E3M³	HV MJ/M³	Park East HV MJ/M³	Calc using Park East HV GJ
6/24/2017	96346.1573	2534.0641	38.0204	38.0071	96312.4261
6/25/2017	95780.0982	2529.4727	37.8656	37.8920	95846.7801
6/26/2017	150542.9012	3978.9930	37.8344	37.8595	150642.6836
6/27/2017	115651.5226	3056.3361	37.8399	37.8887	115800.5997
6/28/2017	121697.1778	3210.3733	37.9075	37.9514	121838.1597
6/29/2017	113369.8797	2986.5291	37.9604	38.0214	113552.0165
6/30/2017	113652.5766	2999.9468	37.8849	37.9523	113854.8822
7/1/2017	102800.4005	2712.4760	37.8991	37.9478	102932.4962
7/2/2017	100242.4425	2641.4464	37.9498	37.9972	100367.5660
7/3/2017	89861.3943	2366.8307	37.9670	38.0225	89992.8220
7/4/2017	102657.0329	2704.6156	37.9562	38.0326	102863.5619
7/5/2017	108915.5947	2870.5191	37.9428	38.2378	109762.3335
7/6/2017	108578.1659	2853.6275	38.0492	38.3993	109577.2967
7/7/2017	104909.6694	2758.3024	38.0341	38.3989	105915.7761
7/8/2017	53473.9758	1409.0034	37.9516	38.0235	53575.2403
7/9/2017	22240.2042	585.9345	37.9568	38.0217	22278.2275
7/10/2017	8139.0454	214.4764	37.9484	38.0393	8158.5340
7/11/2017	8046.1206	211.8907	37.9730	38.2897	8113.2314
7/12/2017	8429.0667	220.0249	38.3096	38.3983	8448.5832
7/13/2017	9300.2012	242.5973	38.3360	38.3948	9314.4746
7/14/2017	8852.2398	231.3055	38.2708	38.4027	8882.7550
7/15/2017	8394.3086	221.0777	37.9699	38.4011	8489.6274
7/16/2017	17758.7025	467.6084	37.9777	38.4010	17956.6298
7/17/2017	47391.8929	1248.8723	37.9478	38.3959	47951.5741
7/18/2017	121358.9339	3166.8766	38.3213	38.3939	121588.7434
7/19/2017	143787.6550	3751.6069	38.3270	38.3910	144027.9421
7/20/2017	147156.1386	3828.4579	38.4374	38.5575	147615.7645
7/21/2017	120930.1571	3140.1521	38.5109	38.5521	121059.4576
7/22/2017	120585.9167	3138.3239	38.4237	38.4181	120568.4416
7/23/2017	95935.6480	2497.0754	38.4192	38.3969	95879.9530
7/24/2017	92308.8923	2406.3602	38.3604	38.3841	92365.9714
7/25/2017	118647.4131	3096.1098	38.3214	38.3856	118846.0304
7/26/2017	104764.9379	2730.7609	38.3647	38.3850	104820.2587
7/27/2017	110398.8198	2894.5069	38.1408	38.3823	111097.8340
7/28/2017	89338.0424	2340.5755	38.1693	38.3852	89843.4602
7/29/2017	95441.5918	2510.4600	38.0176	38.3851	96364.2566
7/30/2017	96620.6588	2515.2932	38.4133	38.3858	96551.5413
7/31/2017	124698.6422	3248.7588	38.3835	38.4805	125013.8618
8/1/2017	114507.6857	2991.8052	38.2738	38.3932	114864.9763
8/2/2017	121383.2469	3167.1942	38.3252	38.3840	121569.5808
8/3/2017	113680.3307	2965.8335	38.3300	38.3890	113855.3837
8/4/2017	97475.2240	2541.5985	38.3519	38.3787	97543.2481
8/5/2017	67395.6176	1758.2606	38.3308	38.3684	67461.6470
8/6/2017	85909.2642	2241.6215	38.3246	38.3710	86013.2604
8/7/2017	77245.5388	2025.0887	38.1443	38.3716	77705.8931

GasDay	Egy GJ	Vol E3M³	HV MJ/M³	Park East HV MJ/M³	Calc using Park East HV GJ
8/8/2017	63190.0971	1657.8128	38.1165	38.3722	63613.9249
8/9/2017	92180.4357	2412.3111	38.2125	38.3774	92578.2287
8/10/2017	100925.0736	2635.3043	38.2973	38.3890	101166.6954
8/11/2017	83126.9150	2168.7590	38.3293	38.3885	83255.4036
8/12/2017	90792.9828	2378.8750	38.1664	38.3879	91320.0161
8/13/2017	80250.2782	2114.1051	37.9595	38.3898	81160.0711
8/14/2017	96594.8950	2532.2700	38.1456	38.3882	97209.2885
8/15/2017	73542.4119	1923.6009	38.2316	38.3890	73845.1134
8/16/2017	68342.7936	1782.9851	38.3305	38.3892	68447.3709
8/17/2017	83651.5047	2182.6171	38.3262	38.3836	83776.7009
8/18/2017	83248.6276	2174.7991	38.2788	38.4728	83670.6115
8/19/2017	82636.0853	2156.0724	38.3271	38.3972	82787.1447
8/20/2017	97759.4038	2551.1026	38.3205	38.3896	97935.8085
8/21/2017	84345.5369	2200.4904	38.3303	38.3940	84485.6303
8/22/2017	74509.1819	1943.7521	38.3327	38.4161	74671.3738
8/23/2017	88470.2214	2297.4170	38.5086	38.4958	88440.9072
8/24/2017	77843.1123	2021.7303	38.5032	38.4047	77643.9473
8/25/2017	51342.8798	1341.6270	38.2691	38.4002	51518.7460
8/26/2017	62170.7290	1633.2419	38.0658	38.4003	62716.9790
8/27/2017	61533.8205	1616.4721	38.0667	38.4001	62072.6901
8/28/2017	55035.7043	1435.4259	38.3410	38.3997	55119.9245
8/29/2017	28402.6444	741.6670	38.2957	38.3958	28476.8996
8/30/2017	50774.5397	1325.0105	38.3201	38.3916	50869.2718
8/31/2017	76290.4314	1993.0476	38.2783	38.3885	76510.1071
9/1/2017	99113.0371	2584.9497	38.3423	38.3886	99232.6011
9/2/2017	73593.2078	1917.2265	38.3852	38.3887	73599.8329
9/3/2017	54937.1451	1432.8360	38.3415	38.3891	55005.2860
9/4/2017	53382.8979	1392.4840	38.3365	38.3890	53456.0689
9/5/2017	49833.8615	1308.1610	38.0946	38.3893	50219.3845
9/6/2017	77861.4290	2045.7304	38.0605	38.3984	78552.7744
9/7/2017	79143.0177	2070.2173	38.2293	38.3840	79463.2210
9/8/2017	47908.1133	1259.6673	38.0324	38.3846	48351.8247
9/9/2017	77854.3311	2048.8956	37.9982	38.3842	78645.2198
9/10/2017	93835.4156	2469.7113	37.9945	38.3844	94798.3880
9/11/2017	69004.8990	1817.6040	37.9648	38.3843	69767.4571
9/12/2017	63267.6010	1665.0486	37.9975	38.3844	63911.8907
9/13/2017	71845.5017	1888.1278	38.0512	38.3846	72475.0290
9/14/2017	115922.2856	3045.2100	38.0671	38.3847	116889.4735
9/15/2017	122225.7835	3214.2033	38.0268	38.3851	123377.5141
9/16/2017	121250.0442	3190.5689	38.0026	38.3850	122469.9879
9/17/2017	105588.1411	2776.7372	38.0260	38.3850	106585.0590
9/18/2017	87799.7880	2305.0709	38.0898	38.4206	88562.2073
9/19/2017	169551.1482	4422.1913	38.3410	38.4546	170053.5975
9/20/2017	143718.8934	3770.3139	38.1185	38.4212	144859.9834
9/21/2017	133600.2656	3486.6436	38.3177	38.3869	133841.4402

GasDay	Egy GJ	Vol E3M³	HV MJ/M³	Park East HV MJ/M³	Calc using Park East HV GJ
9/22/2017	104676.4456	2751.8457	38.0386	38.3869	105634.8240
9/23/2017	123965.3663	3257.8983	38.0507	38.3826	125046.6074
9/24/2017	148468.8056	3881.3585	38.2518	38.3743	148944.4160
9/25/2017	155348.7344	4052.2731	38.3362	38.4212	155693.1934
9/26/2017	134771.3218	3511.3525	38.3816	38.4259	134926.8786
9/27/2017	79998.8884	2087.3416	38.3257	38.3832	80118.8483
9/28/2017	93770.9164	2445.1393	38.3499	38.3790	93842.0010
9/29/2017	82937.6959	2175.9612	38.1154	38.3791	83511.4329
9/30/2017	14742.6645	386.9198	38.1026	38.3793	14849.7107
10/1/2017	80872.0377	2112.0775	38.2903	38.4262	81159.1140
10/2/2017	12818.5048	335.5762	38.1985	38.4168	12891.7649
10/3/2017	34460.1741	899.1071	38.3271	38.3973	34523.2835
10/4/2017	43733.6541	1150.3997	38.0161	38.3973	44172.2419
10/5/2017	43984.2610	1158.5666	37.9644	38.3979	44486.5230
10/6/2017	45808.5683	1203.7885	38.0537	38.3979	46222.9517
10/7/2017	41068.6044	1075.6676	38.1796	38.3930	41298.1071
10/8/2017	37373.5360	974.7624	38.3412	38.4030	37433.8001
10/9/2017	41651.4308	1086.3800	38.3397	38.3885	41704.4979
10/10/2017	79915.4170	2083.9253	38.3485	38.4401	80106.2987
10/11/2017	53366.2201	1391.3762	38.3550	38.4041	53434.5501
10/12/2017	43593.8520	1136.0381	38.3736	38.4531	43684.1854
10/13/2017	50498.6795	1314.0957	38.4285	38.4829	50570.2126
10/14/2017	80341.8940	2090.8856	38.4248	38.4468	80387.8623
10/15/2017	76653.0759	1999.2780	38.3404	38.3841	76740.4864
10/16/2017	77075.4838	2004.8681	38.4442	38.5116	77210.6785
10/17/2017	37135.4166	965.4527	38.4643	38.4574	37128.7994
10/18/2017	31417.6594	818.5836	38.3805	38.4485	31473.3119
10/19/2017	14744.7389	384.0845	38.3893	38.4597	14771.7758
10/20/2017	19464.4786	506.6715	38.4164	38.4552	19484.1532
10/21/2017	40466.3949	1055.2523	38.3476	38.3948	40516.2017
10/22/2017	48021.8369	1251.3854	38.3749	38.3960	48048.1957
10/23/2017	58874.0371	1535.0801	38.3524	38.3948	58939.0947
10/24/2017	19032.0399	496.2511	38.3516	38.3955	19053.8076
10/25/2017	47259.5412	1232.7369	38.3371	38.3958	47331.9206
10/26/2017	68381.4911	1766.1082	38.7187	38.5036	68001.5221
10/27/2017	27471.1811	711.6270	38.6033	38.6189	27482.2538
10/28/2017	46389.9143	1198.2897	38.7134	38.8747	46583.1541
10/29/2017	61558.8042	1595.2435	38.5890	38.5327	61469.0405
10/30/2017	23975.2607	624.1010	38.4157	38.4721	24010.4751
10/31/2017	73057.8127	1898.8073	38.4756	38.5339	73168.4505
11/1/2017	46902.3702	1218.9559	38.4775	38.5129	46945.5271
11/2/2017	83721.6151	2176.6657	38.4632	38.4858	83770.7194
11/3/2017	41141.6735	1071.8631	38.3833	38.3855	41143.9995
11/4/2017	37735.7859	977.9385	38.5871	38.3980	37550.8840
11/5/2017	33125.8082	867.2249	38.1975	38.3991	33300.6547

GasDay	Egy GJ	Vol E3M³	HV MJ/M³	Park East HV MJ/M³	Calc using Park East HV GJ
11/6/2017	27032.4343	708.3052	38.1650	38.5187	27282.9971
11/7/2017	18271.7801	472.3864	38.6797	38.7525	18306.1521
11/8/2017	22358.3588	577.1507	38.7392	38.8014	22394.2541
11/9/2017	110436.0252	2852.0557	38.7216	38.7737	110584.7519
11/10/2017	98289.1046	2537.8847	38.7288	38.7975	98463.5819
11/11/2017	124716.2768	3219.8785	38.7332	38.8245	125010.1715
11/12/2017	77534.7884	1992.5587	38.9122	38.9709	77651.8068
11/13/2017	120179.3262	3094.9304	38.8310	38.8981	120386.9141
11/14/2017	124381.9572	3201.2610	38.8541	38.9448	124672.4681
11/15/2017	145958.7110	3752.9714	38.8915	38.9494	146175.9851
11/16/2017	181398.5789	4674.1242	38.8091	38.8669	181668.7194
11/17/2017	133124.1210	3431.7697	38.7917	38.8767	133415.8801
11/18/2017	71945.5501	1856.9743	38.7434	38.7990	72048.7446
11/19/2017	130575.0523	3367.9195	38.7702	38.8401	130810.3318
11/20/2017	74366.9438	1918.2167	38.7688	38.8473	74517.5388
11/21/2017	169544.8599	4377.9390	38.7271	38.8506	170085.5582
11/22/2017	164610.6209	4247.6614	38.7532	38.8518	165029.2930
11/23/2017	184613.7937	4763.9231	38.7525	38.8521	185088.4181
11/24/2017	74827.8917	1932.0278	38.7302	38.7305	74828.4035
11/25/2017	33492.2295	866.1239	38.6691	38.7317	33546.4523
11/26/2017	85548.4025	2210.3073	38.7043	38.7820	85720.1364
11/27/2017	108697.0106	2807.4286	38.7176	38.7775	108865.0644
11/28/2017	68246.6970	1765.5266	38.6552	38.6738	68279.6226
11/29/2017	65365.3367	1688.8886	38.7032	38.8191	65561.1348
11/30/2017	67209.6885	1737.3809	38.6845	38.7471	67318.4718
12/1/2017	55554.5955	1432.2051	38.7896	38.9045	55719.2249
12/2/2017	40863.6393	1052.6369	38.8203	38.8635	40909.1529
12/3/2017	61266.5524	1582.7863	38.7080	38.7563	61342.9424
12/4/2017	31931.6276	825.4590	38.6835	38.7260	31966.7264
12/5/2017	43400.3823	1123.2473	38.6383	38.7052	43475.5110
12/6/2017	168166.0348	4343.2099	38.7193	38.8449	168711.5554
12/7/2017	159321.8690	4114.9224	38.7181	38.8428	159835.1072
12/8/2017	184728.9566	4761.0325	38.8002	38.8408	184922.3093
12/9/2017	198315.4061	5121.5342	38.7219	38.8415	198928.0691
12/10/2017	213205.4699	5505.3778	38.7268	38.8419	213839.3338
12/11/2017	221636.8869	5727.2095	38.6989	38.8405	222447.6817
12/12/2017	206320.9743	5330.9481	38.7025	38.8381	207043.8935
12/13/2017	167774.3034	4335.3866	38.6988	38.8350	168364.7388
12/14/2017	116762.4684	3015.6808	38.7184	38.8305	117100.3914
12/15/2017	103444.5432	2668.5241	38.7647	38.8280	103613.4541
12/16/2017	114478.1867	2952.1221	38.7783	38.8282	114625.5867
12/17/2017	112618.4889	2905.7024	38.7578	38.8279	112822.3233
12/18/2017	28665.9888	734.3148	39.0377	38.8300	28513.4435
12/19/2017	50429.6073	1288.2721	39.1452	39.2084	50511.0891
12/20/2017	164308.6246	4194.4150	39.1732	39.2013	164426.5191

GasDay	Egy GJ	Vol E3M³	HV MJ/M³	Park East HV MJ/M³	Calc using Park East HV GJ
12/21/2017	181937.0181	4665.2520	38.9983	39.1984	182870.4156
12/22/2017	133648.4403	3448.8175	38.7520	39.1931	135169.8488
12/23/2017	109020.0808	2813.3096	38.7515	39.1934	110263.1669
12/24/2017	123344.8853	3181.5670	38.7686	39.1926	124693.8831
12/25/2017	254903.1712	6574.0013	38.7744	39.1945	257664.6955
12/26/2017	126083.5567	3252.3485	38.7669	39.1224	127239.6795
12/27/2017	135412.9234	3488.0015	38.8225	38.8841	135627.7982
12/28/2017	152202.9457	3920.1768	38.8255	38.8897	152454.5015
12/29/2017	147625.1285	3803.5223	38.8127	38.8778	147872.5788
12/30/2017	245048.5348	6313.4822	38.8135	38.8781	245456.1913
12/31/2017	128247.9413	3304.1522	38.8142	38.8749	128448.5872
1/1/2018	61453.8760	1585.2516	38.7660	38.8293	61554.2089
1/2/2018	203743.5241	5261.2762	38.7251	38.8019	204147.5112
1/3/2018	237362.3527	6132.1104	38.7081	38.7858	237838.8091
1/4/2018	158668.3320	4095.3589	38.7435	38.8064	158926.1344
1/5/2018	80609.3443	2079.2457	38.7686	38.8480	80774.5385
1/6/2018	71627.5479	1846.2091	38.7971	38.8699	71761.9643
1/7/2018	57090.0181	1469.5662	38.8482	38.8856	57144.9639
1/8/2018	118694.6562	3043.4306	39.0003	38.8903	118359.9279
1/9/2018	96378.9773	2473.3450	38.9671	38.8905	96189.6249
1/10/2018	104137.0989	2669.6550	39.0077	39.0493	104248.1606
1/11/2018	36057.6161	928.2704	38.8439	38.9582	36163.7435
1/12/2018	152855.5497	3935.4513	38.8407	38.8317	152820.2645
1/13/2018	72440.3445	1861.2191	38.9209	38.9572	72507.8859
1/14/2018	94961.2776	2443.7440	38.8589	38.9297	95134.2202
1/15/2018	107064.0432	2755.4031	38.8560	38.9152	107227.0638
1/16/2018	183320.2499	4719.2909	38.8449	38.9083	183619.5855
1/17/2018	126839.8063	3269.2527	38.7978	38.8557	127029.1025
1/18/2018	146196.4044	3766.2088	38.8179	38.8951	146487.0691
1/19/2018	112385.4331	2900.1448	38.7517	38.9142	112856.8157
1/20/2018	118240.5691	3050.7170	38.7583	38.9145	118717.1259
1/21/2018	152886.0852	3945.6465	38.7480	38.9145	153542.8594
1/22/2018	141276.1492	3640.3461	38.8084	38.9129	141656.4249
1/23/2018	162033.2025	4170.4781	38.8524	38.9135	162287.8999
1/24/2018	94337.8213	2431.4488	38.7990	38.8863	94550.0482
1/25/2018	108091.0367	2788.1401	38.7682	38.8494	108317.5708
1/26/2018	61739.4591	1593.4775	38.7451	38.8345	61881.9008
1/27/2018	73167.3742	1889.0272	38.7328	38.8373	73364.7157
1/28/2018	71220.5241	1837.5053	38.7594	38.8395	71367.7871
1/29/2018	86496.9748	2230.6286	38.7770	38.8415	86640.9617
1/30/2018	114331.5233	2948.9529	38.7702	38.8411	114540.5731
1/31/2018	138078.8489	3560.1642	38.7844	38.8566	138335.8771
2/1/2018	150656.9886	3885.0888	38.7783	38.8411	150901.1225
2/2/2018	160396.3665	4133.1876	38.8069	38.8762	160682.6294
2/3/2018	102832.9702	2650.0679	38.8039	38.8774	103027.7509

GasDay	Egy GJ	Vol E3M³	HV MJ/M³	Park East HV MJ/M³	Calc using Park East HV GJ
2/4/2018	209467.0159	5401.5948	38.7787	38.8534	209870.3222
2/5/2018	209524.0905	5403.6116	38.7748	38.8507	209934.0917
2/6/2018	153536.3261	3957.8275	38.7931	38.8912	153924.6602
2/7/2018	221474.5804	5709.6525	38.7895	38.8708	221938.7592
2/8/2018	193202.2718	4982.5534	38.7758	38.8509	193576.6837
2/9/2018	111998.9725	2890.4565	38.7478	38.8262	112225.4404
2/10/2018	82652.6595	2133.9356	38.7325	38.8260	82852.1838
2/11/2018	138541.2575	3579.9451	38.6993	38.8274	138999.9619
2/12/2018	119947.0703	3100.9486	38.6808	38.8282	120404.2506
2/13/2018	85331.3023	2203.4999	38.7253	38.8140	85526.6433
2/14/2018	93982.1891	2426.4315	38.7327	38.7970	94138.2610
2/15/2018	135338.7915	3497.7356	38.6933	38.7984	135706.5431
2/16/2018	146980.8464	3794.3097	38.7372	38.8006	147221.4922
2/17/2018	81766.9567	2109.4383	38.7624	38.8014	81849.1582
2/18/2018	143928.1082	3713.3212	38.7599	38.8019	144083.9166
2/19/2018	157411.6591	4066.1663	38.7125	38.8021	157775.7928
2/20/2018	84379.5358	2183.8048	38.6388	38.8040	84740.3622
2/21/2018	68317.0916	1766.9839	38.6631	38.8026	68563.5700
2/22/2018	76128.1793	1964.6167	38.7496	38.8028	76232.6303
2/23/2018	84212.6416	2174.2290	38.7322	38.8049	84370.7405
2/24/2018	104153.2302	2692.0788	38.6888	38.8048	104465.5800
2/25/2018	40286.3669	1042.0050	38.6624	38.8078	40437.9198
2/26/2018	154115.2444	3988.3848	38.6410	38.7376	154500.4566
2/27/2018	154842.6530	4003.8736	38.6732	38.7448	155129.2803
2/28/2018	86046.5556	2227.7037	38.6257	38.6936	86197.8752
3/1/2018	181554.8857	4691.0071	38.7028	38.7839	181935.5507
3/2/2018	160652.7872	4153.8341	38.6758	38.7165	160821.9168
3/3/2018	71621.5009	1848.4177	38.7475	38.7151	71561.6748
3/4/2018	73990.5038	1909.1167	38.7564	38.7187	73918.5154
3/5/2018	55661.9509	1435.4934	38.7755	38.7215	55584.4588
3/6/2018	87153.2660	2247.8058	38.7726	38.7246	87045.3810
3/7/2018	62938.0412	1624.5232	38.7425	38.7269	62912.7461
3/8/2018	102764.2150	2652.0800	38.7485	38.7295	102713.7316
3/9/2018	70290.9391	1812.8095	38.7746	38.7333	70216.0936
3/10/2018	86445.5844	2231.0609	38.7464	38.7368	86424.1602
3/11/2018	87920.0477	2268.9802	38.7487	38.7393	87898.7027
3/12/2018	126177.2153	3254.1554	38.7742	38.7427	126074.7650
3/13/2018	156678.7752	4042.9489	38.7536	38.7463	156649.3094
3/14/2018	107350.8802	2770.0556	38.7541	38.7509	107342.1473
3/15/2018	119087.0596	3073.7668	38.7430	38.7913	119235.4085
3/16/2018	115686.7084	2979.7841	38.8239	38.8003	115616.5172
3/17/2018	98965.5967	2546.1495	38.8687	38.8001	98790.8560
3/18/2018	142367.4983	3659.5291	38.9032	38.7998	141988.9980
3/19/2018	187183.4189	4804.9468	38.9564	38.8004	186433.8582
3/20/2018	171264.0637	4405.0064	38.8794	38.8022	170923.9377

GasDay	Egy GJ	Vol E3M³	HV MJ/M³	Park East HV MJ/M³	Calc using Park East HV GJ
3/21/2018	138690.7415	3570.0165	38.8488	38.8041	138531.2767
3/22/2018	122524.1690	3158.3058	38.7943	38.8094	122571.9519
3/23/2018	112246.5520	2890.1664	38.8374	38.8121	112173.4262
3/24/2018	173496.9085	4457.6037	38.9216	38.8158	173025.4541
3/25/2018	108044.3325	2775.5508	38.9272	38.8223	107753.2677
3/26/2018	138160.0472	3550.8127	38.9094	38.8264	137865.2754
3/27/2018	121682.5869	3129.1920	38.8863	38.8195	121473.6701
3/28/2018	165295.0762	4252.7974	38.8674	38.8228	165105.5010
3/29/2018	139242.3158	3582.6216	38.8660	38.8263	139099.9425
3/30/2018	112306.3521	2898.8475	38.7417	38.8312	112565.7265
3/31/2018	102484.7378	2646.7557	38.7209	38.8027	102701.2655
4/1/2018	123205.2359	3166.7919	38.9054	38.9923	123480.4979
4/2/2018	119097.8469	3064.3396	38.8657	38.9644	119400.1532
4/3/2018	125489.8960	3233.7423	38.8064	38.9622	125993.7127
4/4/2018	165544.4163	4271.0775	38.7594	38.9588	166396.0555
4/5/2018	171901.1090	4436.8133	38.7443	38.9547	172834.7303
4/6/2018	143211.4470	3702.2394	38.6824	38.9536	144215.5521
4/7/2018	102794.7638	2657.2569	38.6845	38.9530	103508.1272
4/8/2018	177022.8710	4574.7948	38.6953	38.9508	178191.9177
4/9/2018	131004.1169	3384.0221	38.7125	38.9480	131800.8920
4/10/2018	87066.1121	2248.9741	38.7137	38.9431	87582.0245
4/11/2018	90267.4906	2333.0560	38.6907	38.9396	90848.2676
4/12/2018	100943.4416	2611.5391	38.6529	38.9424	101699.6010
4/13/2018	95254.9647	2462.5899	38.6808	38.9420	95898.1762
4/14/2018	177867.8234	4591.0819	38.7420	38.9376	178765.7086
4/15/2018	262751.1612	6783.6330	38.7331	38.9267	264064.4454
4/16/2018	178628.0887	4621.3082	38.6531	38.9184	179853.9198
4/17/2018	191153.1967	4947.7636	38.6343	38.9104	192519.4603
4/18/2018	374568.8648	9691.3559	38.6498	38.9058	377049.9537
4/19/2018	210634.6100	5455.0906	38.6125	38.9006	212206.2985
4/20/2018	107517.8601	2773.2926	38.7690	38.8975	107874.1498
4/21/2018	26713.6764	690.8443	38.6682	38.8907	26867.4182
4/22/2018	29608.1046	764.2161	38.7431	38.8672	29702.9390
4/23/2018	59693.4338	1528.7494	39.0472	39.0794	59742.6102
4/24/2018	72926.3196	1875.8985	38.8754	38.9567	73078.8159
4/25/2018	83583.0511	2146.8229	38.9334	39.0194	83767.7428
4/26/2018	90700.1616	2324.4443	39.0201	39.0617	90796.7455
4/27/2018	50761.8489	1301.5965	38.9997	39.1848	51002.7988
4/28/2018	98909.8322	2537.5452	38.9786	39.2111	99499.9384
4/29/2018	44910.8732	1156.7016	38.8267	39.3820	45553.2223
4/30/2018	50827.3601	1315.6031	38.6343	39.3644	51787.9262
5/1/2018	92061.6515	2391.7357	38.4916	39.3547	94126.0428
5/2/2018	153215.0028	3977.5315	38.5201	39.3528	156527.0018
5/3/2018	124653.5609	3236.2525	38.5179	39.3497	127345.5641
5/4/2018	48905.4555	1275.8465	38.3318	39.3437	50196.5201

GasDay	Egy GJ	Vol E3M³	HV MJ/M³	Park East HV MJ/M³	Calc using Park East HV GJ
5/5/2018	73105.3257	1894.6397	38.5853	39.3361	74527.7353
5/6/2018	173438.1406	4526.9138	38.3127	39.3309	178047.5922
5/7/2018	114595.1102	2990.5361	38.3193	39.3279	117611.5055
5/8/2018	112369.0082	2925.0787	38.4157	39.3239	115025.5027
5/9/2018	81439.6808	2114.6232	38.5126	39.3204	83147.8290
5/10/2018	70693.9585	1850.0408	38.2121	39.3168	72737.6835
5/11/2018	66190.4917	1739.9778	38.0410	39.3069	68393.1337
5/12/2018	94466.3234	2479.7851	38.0946	39.3003	97456.2995
5/13/2018	93579.1342	2451.4893	38.1724	39.2949	96331.0285
5/14/2018	95395.2387	2501.9963	38.1276	38.9781	97523.0627
5/15/2018	107284.3935	2817.6171	38.0763	38.5814	108707.6125
5/16/2018	88608.0276	2327.2006	38.0749	38.3515	89251.6338
5/17/2018	103179.4261	2709.2617	38.0840	38.3128	103799.4008
5/18/2018	44116.2722	1159.0138	38.0636	38.2415	44322.4255
5/19/2018	53989.0015	1419.1065	38.0444	38.2178	54235.1299
5/20/2018	85711.0788	2250.9282	38.0781	38.1898	85962.4966
5/21/2018	78081.9123	2050.1911	38.0852	38.1356	78185.2684
5/22/2018	94471.6485	2480.8738	38.0800	38.1357	94609.8577
5/23/2018	63956.1708	1676.8567	38.1405	38.1353	63947.4341
5/24/2018	101605.3908	2661.8241	38.1713	38.1383	101517.4465
5/25/2018	99542.7756	2603.6520	38.2320	38.1430	99311.0998
5/26/2018	80713.7342	2111.3962	38.2277	38.1512	80552.2969
5/27/2018	124584.1219	3258.5529	38.2330	38.1608	124348.9838
5/28/2018	115913.1844	3028.4392	38.2749	38.1692	115593.1023
5/29/2018	129145.5250	3374.1647	38.2748	38.1799	128825.2703
5/30/2018	117395.2468	3068.8834	38.2534	38.1876	117193.2931
5/31/2018	134309.4513	3510.2033	38.2626	38.1936	134067.2989
6/1/2018	155727.6247	4072.4277	38.2395	38.2306	155691.3537
6/2/2018	141358.0546	3696.7285	38.2387	38.3189	141654.5710
6/3/2018	150318.4059	3930.2499	38.2465	38.3447	150704.2547
6/4/2018	120273.2407	3149.5244	38.1877	38.3396	120751.5061
6/5/2018	124506.1276	3258.0604	38.2148	38.3217	124854.4149
6/6/2018	153369.9120	3997.2161	38.3692	38.3207	153176.1198
6/7/2018	96422.9569	2503.1264	38.5210	38.3197	95919.0516
6/8/2018	81829.4176	2117.3799	38.6465	38.3192	81136.3028
6/9/2018	62881.4106	1628.5708	38.6114	38.3215	62409.2755
6/10/2018	70694.4805	1830.9705	38.6104	38.3286	70178.5364
6/11/2018	82169.0403	2125.0906	38.6661	38.3391	81474.0615
6/12/2018	121096.5157	3131.8171	38.6665	38.3519	120111.1379
6/13/2018	265857.4977	6901.2482	38.5231	38.3611	264739.4727
6/14/2018	256161.8726	6653.3398	38.5012	38.3695	255285.3230
6/15/2018	260052.0591	6758.8261	38.4759	38.3815	259413.8840
6/16/2018	244352.9443	6358.9407	38.4267	38.3785	244046.6068
6/17/2018	288246.2170	7499.0632	38.4376	38.3773	287793.7993
6/18/2018	276398.3945	7192.9110	38.4265	38.3784	276052.4155

GasDay	Egy GJ	Vol E3M³	HV MJ/M³	Park East HV MJ/M³	Calc using Park East HV GJ
6/19/2018	260517.1905	6793.8415	38.3461	38.3818	260759.8666
6/20/2018	260662.0619	6797.3993	38.3473	38.3847	260916.1344
6/21/2018	253471.8751	6601.6680	38.3951	38.3795	253368.7174
6/22/2018	250928.0556	6528.1636	38.4378	38.3466	250332.8764
6/23/2018	231445.1881	5999.7304	38.5759	38.3355	230002.6651
6/24/2018	252101.0165	6542.9397	38.5302	38.3378	250841.9148
6/25/2018	269692.9186	7005.7301	38.4960	38.3478	268654.3360
6/26/2018	271536.0370	7053.7751	38.4951	38.3691	270647.0018
6/27/2018	283284.7663	7380.0887	38.3850	38.3694	283169.5771
6/28/2018	298073.8492	7777.4223	38.3255	38.3696	298416.5815
6/29/2018	293235.5371	7653.6969	38.3129	38.3701	293673.1135
6/30/2018	253866.1221	6624.7526	38.3208	38.3910	254330.8757
7/1/2018	247852.1824	6464.2688	38.3419	38.4104	248295.1484
7/2/2018	288266.3832	7520.5740	38.3304	38.4013	288799.8167
7/3/2018	270522.9787	7016.9316	38.5529	38.5298	270360.9718
7/4/2018	322106.6483	8325.1866	38.6906	38.7190	322342.8988
7/5/2018	299573.2867	7783.8112	38.4867	38.5806	300304.1079
7/6/2018	229881.8226	5981.9601	38.4292	38.5287	230477.1461
7/7/2018	226827.7487	5881.2567	38.5679	38.5531	226740.6761
7/8/2018	244583.1781	6326.7163	38.6588	38.5530	243913.8951
7/9/2018	274095.4759	7111.9426	38.5402	38.5529	274186.0116
7/10/2018	268002.1815	6938.3624	38.6261	38.4400	266710.6518
7/11/2018	285000.7894	7438.9503	38.3120	38.3876	285563.4501
7/12/2018	288746.6634	7530.1618	38.3453	38.4059	289202.6411
7/13/2018	276104.6621	7191.4932	38.3932	38.4001	276154.0569
7/14/2018	242836.7904	6327.2422	38.3796	38.4016	242976.2245
7/15/2018	291193.9150	7586.6297	38.3825	38.4049	291363.7538
7/16/2018	285184.4292	7428.8219	38.3889	38.4297	285487.3981
7/17/2018	269156.6182	7014.0074	38.3742	38.4389	269610.7275
7/18/2018	275747.1062	7182.5295	38.3914	38.4733	276335.6111
7/19/2018	270437.0169	7045.8347	38.3825	38.4758	271094.1248
7/20/2018	242131.9454	6322.1071	38.2992	38.4496	243082.4900
7/21/2018	204674.7723	5312.5752	38.5265	38.3672	203828.6363
7/22/2018	244878.6216	6352.3803	38.5491	38.3684	243730.6671
7/23/2018	303498.1679	7924.9917	38.2963	38.3686	304070.8365
7/24/2018	315940.9524	8244.6021	38.3209	38.4142	316709.7921
7/25/2018	306364.6673	7909.9651	38.7315	38.6825	305977.2254
7/26/2018	265859.6732	6880.0453	38.6421	38.5898	265499.5703
7/27/2018	253965.3128	6625.5073	38.3315	38.4392	254679.2019
7/28/2018	238483.9898	6211.5970	38.3933	38.4518	238847.0844
7/29/2018	275364.8016	7177.6428	38.3642	38.4179	275749.9626
7/30/2018	290792.9829	7588.9300	38.3180	38.3686	291176.6192
7/31/2018	277924.8357	7255.4457	38.3057	38.3747	278425.5536
8/1/2018	285826.5673	7454.9932	38.3403	38.4082	286332.8694
8/2/2018	299651.8087	7808.7475	38.3739	38.4575	300304.9058

GasDay	Egy GJ	Vol E3M³	HV MJ/M³	Park East HV MJ/M³	Calc using Park East HV GJ
8/3/2018	279940.5845	7290.3117	38.3990	38.4615	280396.3223
8/4/2018	244965.8756	6379.5907	38.3984	38.4752	245456.0298
8/5/2018	232773.0887	6064.5081	38.3828	38.4472	233163.3556
8/6/2018	266713.6154	6946.6797	38.3944	38.4590	267162.3535
8/7/2018	300854.9399	7820.4427	38.4703	38.4557	300740.5964
8/8/2018	283481.8345	7313.3247	38.7624	38.4541	281227.3179
8/9/2018	276031.4722	7141.2388	38.6532	38.4555	274619.9085
8/10/2018	282206.7258	7308.1494	38.6153	38.4560	281042.1926
8/11/2018	253513.1613	6573.1835	38.5678	38.5351	253298.2826
8/12/2018	294337.5254	7555.3465	38.9575	38.5377	291165.6754
8/13/2018	288521.9924	7555.5550	38.1867	38.4881	290798.9572
8/14/2018	302421.3087	7911.7572	38.2243	38.4400	304127.9475
8/15/2018	335690.9342	8749.0756	38.3687	38.4749	336619.8069
8/16/2018	317960.6411	8258.1895	38.5025	38.6880	319492.8342
8/17/2018	282965.6223	7290.0385	38.8154	38.7030	282146.3605
8/18/2018	242947.9438	6287.7897	38.6381	38.4701	241891.8969
8/19/2018	251935.1964	6579.4284	38.2914	38.4705	253113.9010
8/20/2018	310501.0855	8163.4888	38.0353	38.4707	314055.1289
8/21/2018	265570.9059	6984.1683	38.0247	38.4150	268296.8268
8/22/2018	241722.4532	6343.9895	38.1026	38.4541	243952.4068
8/23/2018	241900.3546	6329.9473	38.2152	38.4370	243304.1844
8/24/2018	259859.7905	6841.1147	37.9850	38.4343	262933.4547
8/25/2018	243234.7064	6398.9231	38.0118	38.4350	245942.6078
8/26/2018	302146.7863	7924.9196	38.1262	38.4352	304595.8710
8/27/2018	285518.5521	7459.4852	38.2759	38.3904	286372.6191
8/28/2018	295942.4881	7718.4985	38.3420	38.5056	297205.4143
8/29/2018	278188.6392	7250.1600	38.3700	39.1602	283917.7156
8/30/2018	284234.6001	7407.7300	38.3700	38.9220	288323.6671
8/31/2018	253105.4027	6596.4400	38.3700	38.6443	254914.8062
9/1/2018	242842.1951	6328.9600	38.3700	38.5117	243739.0088
9/2/2018	267541.7317	6972.6800	38.3700	38.3821	267626.1011
9/3/2018	297945.8675	7774.2227	38.3248	38.3711	298305.4766
9/4/2018	349767.9317	9127.4745	38.3203	38.3853	350360.8469
9/5/2018	335075.7894	8743.3798	38.3234	38.3897	335655.7290
9/6/2018	281142.4865	7307.7678	38.4717	38.5688	281851.8340
9/7/2018	243923.0716	6347.8763	38.4259	38.5381	244635.0913
9/8/2018	220681.8524	5751.8570	38.3671	38.5606	221795.0559
9/9/2018	240932.1565	6292.1869	38.2907	38.5648	242656.9305
9/10/2018	204943.5426	5343.1471	38.3563	38.3889	205117.5389
9/11/2018	271049.5714	7081.3192	38.2767	38.3689	271702.4294
9/12/2018	271796.3996	7094.3135	38.3119	38.4070	272471.2987
9/13/2018	284115.9702	7416.5419	38.3084	38.3957	284763.3186
9/14/2018	286797.1859	7497.8133	38.2508	38.3904	287844.0516
9/15/2018	239427.0324	6270.9593	38.1803	38.4083	240856.8857
9/16/2018	259190.9127	6780.5383	38.2257	38.3922	260319.7814

GasDay	Egy GJ	Vol E3M³	HV MJ/M³	Park East HV MJ/M³	Calc using Park East HV GJ
9/17/2018	292954.6404	7650.0758	38.2943	38.4168	293891.4320
9/18/2018	266311.4813	6937.4941	38.3873	38.4519	266759.8294
9/19/2018	253823.8363	6608.2653	38.4101	38.4765	254262.9198
9/20/2018	258590.8935	6735.3974	38.3928	38.4684	259099.9629
9/21/2018	209605.4933	5495.9262	38.1383	38.4625	211387.0621
9/22/2018	243416.4284	6402.2106	38.0207	38.4587	246220.6972
9/23/2018	236101.1988	6171.7322	38.2553	38.4553	237335.8125
9/24/2018	236032.1356	6199.2395	38.0744	38.4575	238407.2546
9/25/2018	130968.4390	3413.8221	38.3642	38.4401	131227.6645
9/26/2018	75319.9682	1968.8159	38.2565	38.4211	75644.0711
9/27/2018	165899.9952	4321.9844	38.3851	38.4533	166194.5630
9/28/2018	263860.0413	6874.7488	38.3810	38.4123	264074.9129
9/29/2018	214343.9799	5659.0758	37.8761	38.4044	217333.4122
9/30/2018	152280.6032	4007.8329	37.9957	38.4015	153906.7959
10/1/2018	145320.2035	3789.1181	38.3520	38.4334	145628.6915
10/2/2018	115719.6515	3011.2143	38.4296	38.5426	116060.0283
10/3/2018	127557.6143	3303.2609	38.6157	38.6674	127728.5115
10/4/2018	105600.3223	2730.7304	38.6711	38.7857	105913.2903
10/5/2018	99722.3939	2563.2186	38.9051	38.9051	99722.2767
10/6/2018	74290.0341	1916.3026	38.7674	38.6363	74038.8428
10/7/2018	88261.9849	2279.0785	38.7270	38.5482	87854.3753
10/8/2018	63427.8672	1648.5474	38.4750	38.4951	63460.9961
10/9/2018	224522.3141	5826.6076	38.5340	38.5078	224369.8417
10/10/2018	224188.0901	5817.9708	38.5337	38.4766	223855.7351
10/11/2018	172596.4192	4497.0128	38.3802	38.4975	173123.7483
10/12/2018	200220.0774	5182.5381	38.6336	38.9287	201749.4713
10/13/2018	182431.1736	4760.7300	38.3200	38.7917	184676.8099
10/14/2018	127610.2795	3324.0500	38.3900	38.6816	128579.5724
10/15/2018	163240.2408	4242.2100	38.4800	38.9119	165072.4513
10/16/2018	149736.0566	3886.2200	38.5300	38.9122	151221.3699
10/17/2018	198610.5910	5154.7000	38.5300	39.1352	201730.2155
10/18/2018	180427.2636	4687.6400	38.4900	39.0506	183055.1546
10/19/2018	139376.0406	3622.9800	38.4700	39.0366	141428.8211
10/20/2018	156031.5494	4078.1900	38.2600	39.0012	159054.3038
10/21/2018	101539.8020	2658.1100	38.2000	39.2646	104369.6259
10/22/2018	169125.5607	4428.5300	38.1900	39.2169	173673.2181
10/23/2018	211313.6718	5533.2200	38.1900	39.1678	216724.0543
10/24/2018	251755.6560	6607.7600	38.1000	39.2475	259338.0606
10/25/2018	208602.4950	5453.6600	38.2500	39.2324	213960.1706
10/26/2018	267714.8100	6999.0800	38.2500	39.1463	273988.0854
10/27/2018	274039.2408	7177.5600	38.1800	39.1493	280996.4497
10/28/2018	237888.5900	6227.4500	38.2000	39.1545	243832.6910
10/29/2018	242754.0267	6300.3900	38.5300	39.1815	246858.7308
10/30/2018	252562.8732	6516.0700	38.7600	39.2145	255524.4270
10/31/2018	204318.5544	5304.2200	38.5200	39.2075	207965.2057

GasDay	Egy GJ	Vol E3M³	HV MJ/M³	Park East HV MJ/M³	Calc using Park East HV GJ
11/1/2018	241822.5804	6290.9100	38.4400	39.2044	246631.3520
11/2/2018	217309.7367	5654.6900	38.4300	39.2030	221680.8120
11/3/2018	244940.3219	6398.6500	38.2800	39.2026	250843.7164
11/4/2018	201235.3232	5262.4300	38.2400	39.2005	206289.8872
11/5/2018	228864.2830	5994.3500	38.1800	39.2002	234979.7188
11/6/2018	181042.7704	4763.0300	38.0100	39.2011	186716.0154
11/7/2018	227781.6503	5998.9900	37.9700	39.2010	235166.4070
11/8/2018	279132.0400	7345.5800	38.0000	39.2027	287966.5690
11/9/2018	291130.2984	7655.2800	38.0300	39.2114	300174.2462
11/10/2018	275627.8558	7241.9300	38.0600	39.2424	284190.7138
11/11/2018	282070.7918	7417.0600	38.0300	39.2627	291213.8017
11/12/2018	310684.8528	8167.3200	38.0400	39.2785	320800.0786
11/13/2018	308237.7136	8105.1200	38.0300	39.3146	318649.5507
11/14/2018	225053.0289	5920.8900	38.0100	39.3300	232868.6037
11/15/2018	200695.3387	5277.2900	38.0300	39.3390	207603.3113
11/16/2018	151595.8821	3982.0300	38.0700	39.3461	156677.3506
11/17/2018	219848.8898	5787.0200	37.9900	39.3544	227744.6999
11/18/2018	268341.0016	7046.7700	38.0800	39.3527	277309.4258
11/19/2018	267562.6881	7020.8000	38.1100	39.3544	276299.3716
11/20/2018	203406.0102	5334.5400	38.1300	39.3592	209963.2268
11/21/2018	221580.1240	5812.7000	38.1200	39.3623	228801.2412
11/22/2018	195877.3143	5091.6900	38.4700	39.3665	200442.0144
11/23/2018	139732.8138	3591.1800	38.9100	39.3763	141407.3810
11/24/2018	99874.3267	2599.5400	38.4200	39.3687	102340.5103
11/25/2018	128141.0982	3342.2300	38.3400	39.3632	131560.8679
11/26/2018	118574.9796	3091.1100	38.3600	39.3577	121658.9800
11/27/2018	159812.0805	4171.5500	38.3100	39.3518	164158.0013
11/28/2018	129389.5930	3318.4195	38.9913	39.3580	130606.3529
11/29/2018	176655.7981	4489.7487	39.3465	39.3613	176722.3460
11/30/2018	236387.2313	6086.1800	38.8400	39.3668	239593.4309
12/1/2018	153926.0901	3968.1900	38.7900	39.3710	156231.6085
12/2/2018	106734.7524	2759.4300	38.6800	39.3786	108662.4902
12/3/2018	154051.1974	3989.9300	38.6100	39.3715	157089.5291
12/4/2018	186156.1612	4811.4800	38.6900	39.3775	189464.0537
12/5/2018	122809.3614	3153.8100	38.9400	39.3809	124199.8762
12/6/2018	154195.7388	3964.9200	38.8900	39.3830	156150.4444
12/7/2018	176235.7232	4537.4800	38.8400	39.3852	178709.5573
12/8/2018	144718.2451	3726.9700	38.8300	39.3854	146788.2043
12/9/2018	200364.7093	5111.3316	39.2001	39.3879	201324.6174
12/10/2018	246998.0158	6296.1039	39.2303	39.3871	247985.2757
12/11/2018	272002.2525	6927.0551	39.2667	39.3878	272841.4611
12/12/2018	247760.9250	6307.2101	39.2822	39.3878	248427.1285
12/13/2018	146796.3380	3736.7676	39.2843	39.3879	147183.4298
12/14/2018	276218.8728	7031.2772	39.2843	39.3876	276945.1334
12/15/2018	247429.4021	6298.4281	39.2843	39.3864	248072.4086

GasDay	Egy	Vol	HV	Park East HV	Calc using Park East HV
	GJ	E3M³	MJ/M³	MJ/M³	GJ
12/16/2018	240238.8769	6115.3900	39.2843	39.3859	240860.1394
12/17/2018	247160.7398	6291.5892	39.2843	39.3861	247801.1607
12/18/2018	285022.4046	7255.3751	39.2843	39.3868	285766.0080
12/19/2018	201793.5728	5136.7473	39.2843	39.3882	202327.2295
12/20/2018	170188.2860	4332.2203	39.2843	39.3872	170634.0281
12/21/2018	156443.3859	3982.3376	39.2843	39.3814	156830.0311
12/22/2018	209321.9770	5328.3862	39.2843	39.4167	210027.4020
12/23/2018	118651.7678	3020.3348	39.2843	39.4134	119041.6628
12/24/2018	131025.6549	3335.3177	39.2843	39.4132	131455.5440
12/25/2018	127878.5081	3255.2057	39.2843	39.4124	128295.4674
12/26/2018	177172.6745	4510.0111	39.2843	39.4120	177748.5579
12/27/2018	123746.4077	3150.0212	39.2843	39.4099	124142.0188
12/28/2018	160129.7682	4076.1762	39.2843	39.4085	160635.9886
12/29/2018	224146.6904	5705.7561	39.2843	39.4097	224862.1351
12/30/2018	151286.3591	3851.0632	39.2843	39.4072	151759.6163
12/31/2018	196494.8153	5001.8650	39.2843	39.4033	197089.9872

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

Scott Madden Report on UFG, page 34-35

Preamble:

The Madden Report states: *"Gate station meter variations represent a potential source of UFG if there are differences between actual and metered volumes. Gate station meter variations have been recognized by gas utilities and the legacy Companies as a potential source of UFG and have implemented a number of practices and initiatives to monitor and manage gate station meter variations."*

We understand that TransCanada experienced some significant challenges in applying chromatographic readings to delivered gas from October 2018 to January 2019.

Question:

In performing this study, was Scott Madden informed of this issue?

a) If not, why not?

b) If so, please provide their letter of advice or recommendation.

Response

a) and b)

ScottMadden had a conversation with Enbridge Gas personnel regarding the challenges related to measurement variations at TC Energy's gate stations. The discussion focused on process improvements to better monitor and manage measurement variations at the TC Energy gate stations. The process improvements are included in the Report on page 39.

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

ScottMadden Report on UFG, page 34-35

Preamble:

The Madden Report states: *"Gate station meter variations represent a potential source of UFG if there are differences between actual and metered volumes. Gate station meter variations have been recognized by gas utilities and the legacy Companies as a potential source of UFG and have implemented a number of practices and initiatives to monitor and manage gate station meter variations."*

We understand that TransCanada experienced some significant challenges in applying chromatographic readings to delivered gas from October 2018 to January 2019.

Question:

Please confirm that chromatographs were installed recently at TCE's Richmond and Ottawa stations.

a) Please provide a pipeline map with EGI delivery stations for the TransCanada Eastern Ontario triangle.

b) Please indicate where EGI understands chromatographs were located as of October 1, 2017
    i. Please provide which TCE delivery stations to EGI were applied to each of the chromatograph as of October 1, 2017.

c) Please indicate where EGI has knowledge of chromatographs currently.
    i. Please provide which TCE delivery stations to EGI are now applied to each of the chromatograph.

d) What is EGI's understanding of why two chromatographs were added where there were previously none.

Response

a) to d)

The information sought in this series of questions will be known to TC Energy. Enbridge Gas's knowledge of these items is not complete.

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

ScottMadden Report on UFG, page 34-35

Preamble:

The Madden Report states: *"Gate station meter variations represent a potential source of UFG if there are differences between actual and metered volumes. Gate station meter variations have been recognized by gas utilities and the legacy Companies as a potential source of UFG and have implemented a number of practices and initiatives to monitor and manage gate station meter variations."*

We understand that TransCanada experienced some significant challenges in applying chromatographic readings to delivered gas from October 2018 to January 2019.

Question:

Please provide the last year that each of these utilities used orifices plates for custody transfer.

Response

Legacy Union Gas replaced orifice plates with other types of metering for custody transfer prior to 1999.

The last year legacy EGD used orifices for custody transfer was 2016.

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

ScottMadden Report on UFG, page 34-35

Preamble:

The Madden Report states: *"Gate station meter variations represent a potential source of UFG if there are differences between actual and metered volumes. Gate station meter variations have been recognized by gas utilities and the legacy Companies as a potential source of UFG and have implemented a number of practices and initiatives to monitor and manage gate station meter variations."*

We understand that TransCanada experienced some significant challenges in applying chromatographic readings to delivered gas from October 2018 to January 2019.

Question:

Does DTE employ chromatographs or any energy content evaluation at any custody transfer location to verify accuracy?

Response

Their month end reports received from DTE/Michcon include heat value for the St. Clair interconnect with Enbridge Gas which suggests that a chromatograph is being used but Enbridge Gas cannot confirm.

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

Scott Madden Report on UFG, page 39

Preamble:

The report states: *"Legacy EGD implemented various practices and initiatives to monitor and manage gate station meter variations.*

Investment in Facilities

Redesigned the Victoria Square Gate Station to more accurately measure gas flows. The project is scheduled to commence in 2020."

Question:

We would like to understand better the nature of the measurement problem and the approach to resolve.

Please define the underlying problem and the designed fix?

a) Please provide a drawing with dimensions to describe the systemic problem.

b) Is the existing design AGA-8 compliant?

Response

a) Victoria Square Gate Station has a single 30" ultrasonic meter run. The single large size run may have two potential problems: significant uncertainty of measurement expressed in cubic meters due to significant volumes and increased uncertainty at low flow rates.

The approach / designed fix to resolve the above problems is to install two 16” ultrasonic meters in parallel instead of a single meter (this way the uncertainty of measurement will be reduced by square root of two) and install a third, 4” ultrasonic meter run to accurately measure low flows.

b) The existing design is AGA-8 compliant.

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

Scott Madden Report on UFG, page 48

Preamble:

The Madden report states*: UFG is not specifically budgeted for the Union North service area and therefore any UFG actually incurred per the legacy Union North calculation is a volume variance to the budgeted UFG.*

Question:

Please explain this sentence more specifically (e.g., a volume variance to "what" budgeted UFG?).

a) More importantly, who pays for the actual volume variance.

Response

In proceedings leading up to legacy Union Gas' 2014-2018 Incentive Rate Mechanism, a UFG deferral account was proposed and agreed upon between legacy Union Gas and intervenors and submitted for approval by the Board. Before that time, legacy Union Gas had been at full risk of any variance between volumes of UFG included in rates and the volume of UFG actually incurred. The proposed deferral account was designed to account for any volume variances from what was included in rates, with a symmetrical deadband of +/-$5 million. With respect to the symmetrical deadband, legacy Union Gas would assume all risk for UFG within the symmetrical deadband, while ratepayers would be responsible for any UFG (favourable / unfavourable) after exceeding the +/- $5 million threshold.

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

Exhibit B, Tab 1, Schedule 1 Appendix C, page 5, Table 1, lines 16, 20 and 21

Question:

Please confirm that EGD zone transportation needs are included in the M12/C1 Dawn-Parkway.

a) Please provide the revenue requirement associated with these needs for each of the respective columns in Table 1 for each of lines 16, 20 and 21.

Response

Confirmed.

a) Please see Attachment 1.

ENBRIDGE GAS INC.

Summary of Rate M12/C1 Cost Allocation for the EGD Rate Zone

			Board-Approved Methodology			Proposed Methodology	
Line No.	Particulars ($000's)	Current Approved Revenue	Revenue Requirement	Revenue (Deficiency)/ Sufficiency	Impact of Cost Study Proposals	Revenue Requirement	Revenue (Deficiency)/ Sufficiency
		(a)	(b)	(c) = (a-b)	(d)	(e) = (b+d)	(f) = (a-e)
	Ex-Franchise - EGD Rate Zone						
1	Rate M12/C1 - Dawn-Parkway	123,082	108,954	14,128	3,897	112,851	10,231
2	Commodity / Admin	-	-	-	-	-	-
3	Gas Supply and Transportation	-	-	-	-	-	-
4	Total	123,082	108,954	14,128	3,897	112,851	10,231

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

Exhibit B, Tab 1, Schedule 1 Appendix C, page 6, Table 2

Preamble:

We would like to understand the differences in the M4 and M5 contract rates and the changes in C1 attraction of costs.

Question:

Please provide the following information:

a) Please describe the criteria for M4 Firm and Interruptible?

b) Please describe the criteria for M5 Firm and Interruptible?

c) Using the differentiations of the respective rate classes, please describe how those differences drive changes to the attraction of costs for revenue requirement and rate recovery.

Response

a) Rate M4 is a predominately firm industrial and commercial contract rate that is applicable to a customer that specifies a daily firm contracted demand between 2,400 m^3 and 60,000 m^3. In addition, the customer shall purchase from Enbridge Gas or pay for a minimum volume of gas or transportation services equivalent to 146 days use of firm contracted demand (40% load factor).

   Rate M4 customers, under the sole discretion of Enbridge Gas, may agree to combine the firm service with an interruptible service provided that the amount of interruptible volume to be delivered and agreed upon by Enbridge Gas and the customer shall be no less than 350,000 m^3 per year.

b) Rate M5 is a predominately interruptible industrial and commercial contract rate that is applicable to a customer that specifies a daily interruptible contracted demand between 2,400 m^3 and 60,000 m^3. In addition, the customer must take delivery from Enbridge Gas or pay for a minimum volume of gas or transportation services which will not be less than 350,000 m^3 per year (40% load factor).

Rate M5 customers, under the sole discretion of Enbridge Gas, may agree to combine an interruptible service with a firm service in which case the amount of firm daily demand to be delivered shall be agreed to upon by Enbridge Gas and the customer.

c) The allocation of Panhandle / St. Clair, Parkway Station and Dawn Station are underpinned by firm demands on each of the respective transmission systems. Rate M4 is a predominantly firm service with an option to take some incremental interruptible service. Rate M5 is a predominantly interruptible service with an option to take some incremental firm service. Given Rate M4 has proportionately higher firm demands than Rate M5, the allocation of Panhandle / St. Clair, Parkway Station and Dawn Station costs to Rate M4 is greater than Rate M5.

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

Exhibit B, Tab 1, Schedule 1 Appendix C, page 6, Table 2

Preamble:

We would like to understand the differences in the M4 and M5 contract rates and the changes in C1 attraction of costs.

Question:

Please specify what factors contribute to the significant reduction in C1 change in Table 2?

Response

The proposed decrease in allocated costs to Rate C1 is a result of the change in the cost allocation methodology for the Panhandle and St. Clair System.

The Board-approved cost allocation methodology of Panhandle and St. Clair System demand costs, categorized as Ojibway / St.Clair demand, is based on the maximum design capacity of the combined systems, with the allocation to Rate C1 based on contracted demands. The costs allocated to Rate C1 using the Board-approved methodology is $12.634 million.

Enbridge Gas's proposed cost allocation methodology for Panhandle and St. Clair System demand costs includes a direct assignment to Rate C1 of the costs used solely to serve the Rate C1 transmission service. In addition, Rate C1 is assigned a proportionate share of Panhandle System transmission mains and Dawn yard assets as a contribution towards the recovery of Panhandle System costs used to provide the Rate C1 transmission service. The contribution by Rate C1 to the Panhandle demand costs recognizes the Panhandle System is a westerly peaking system on design day used to meet the needs of Union South in-franchise customers however the Rate C1 transmission service can only be facilitiated through the use of the Panhandle System assets. The costs allocated to Rate C1 using the proposed methodology is $5.686 million.

The difference between the Board-approved and proposed cost allocation methodology is a decrease in the costs allocated to Rate C1 of $6.948 million. The decrease is as a result of the difference between an allocation of costs based on Rate C1 contracted demands used in the Board-approved methodology and the direct assignment of costs in the proposed methodology.

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

Ex. B, Tab 1, Sch. 1 App. C, pages 10-11 & EB-2015-0166 Ex. A pages 33-35

Preamble:

EGI states: *"Rate C1 transportation includes Union South and Union North sales service customers that transport volumes on the Panhandle and St. Clair System to Dawn. These customers are charged the firm Rate C1 transportation demand charge for transportation between Dawn and Ojibway, St. Clair and Bluewater to ensure there is no cross subsidy between sales service customers and other customers for the use of these assets. The use of the Rate C1 firm transportation demand rate to charge sales service customers for transportation to Dawn was introduced as part of Union's Pre-Approval of the Cost Consequences of NEXUS Long Term Contract proceeding (EB-2015-0166). "*

Question:

Please file the referenced pages from EB-2015-0166.

a) Is the referenced rate of $0.035/GJ, a rate that is determined using the expectation of $2.8M of S&T revenue from the St. Clair to Dawn service?
    i. If so, what would the rate without the revenue?

b) Is the practical effect that EGI is profiting from the gas commodity revenues? Please explain.

Response

Please see EB-2015-0166, Exhibit A, Attachment 1, pages 33-35.

a) No. Union North and Union South sales service customers are charged the approved Rate C1 demand charge for firm transportation between Dawn and Ojibway, St. Clair and Bluewater for capacity utilized to transport gas supply to Dawn. The Rate C1 transportation demand charge is not derived from the S&T revenue of $2.8 million but is determined through the Board-approved rate design methodology, which sets the Rate C1 demand charge at the average unit rate of demand of the combined Panhandle and St. Clair Systems.

b) Enbridge Gas is not profiting from the gas commodity revenues. Sales service customers are charged Rate C1 for their use of the Panhandle and St. Clair Systems.

The goal of achieving supply diversity has been supported in previous Board decisions. Specifically, the Board has stated that "Supply diversity enhances security and has the tendency to lower gas prices from what they would otherwise be if the market continued to rely on fewer sources of supply."[28] Utica and Marcellus supplies will be transported through the new and existing infrastructure and will have direct access to Dawn via a single pipeline provider.

Cost Recovery of St. Clair to Dawn Transportation from Sales Service Customers

Union is proposing to charge Union North and Union South sales service customers the Board-approved C1 St. Clair to Dawn transportation rate for the volumes transported from St. Clair to Dawn.

In Union's 2013 Board-approved cost allocation study, the cost associated with St. Clair to Dawn transportation capacity are allocated to Union South in-franchise rate classes and ex-franchise rate classes based on the design day demands of the Ojibway/St. Clair transmission system. The costs allocated to Union South in-franchise rate classes are recovered from all customers in delivery rates, while the costs allocated to ex-franchise rate classes (C1 and M16) are recovered in transportation rates.

[28] EB-2012-0433/EB-2013-0074 Decision January 30, 2014, page 29

Union's 2013 Board-approved revenue forecast includes approximately $2.8 million in Storage and Transportation (S&T) revenue associated with St. Clair to Dawn transportation service. This revenue (less allocated costs) is included in revenue for ratemaking purposes. Delivery rates for all customers are lower as a result of forecasted S&T revenue from St. Clair to Dawn. S&T transportation revenue also forms part of utility earnings, which are subject to sharing with ratepayers during Union's 2014 to 2018 IRM term.

With Union North and Union South sales service customers utilizing the majority of the St. Clair to Dawn transportation capacity effective November 1, 2017, Union will have less opportunity to generate S&T revenue on this path. To offset the revenue already included in rates, and to ensure there is no cross-subsidy between sales service customers and other customers, Union is proposing to charge sales service customers for St. Clair to Dawn transportation service in a manner consistent with how Union would charge other customers. Further, this results in the same impact to sales service and bundled direct purchase customers under a scenario where NEXUS would contract to St. Clair transportation service and then charge Union for the full path.

Specifically, Union is proposing to charge Union North and Union South sales service customers the Board-approved C1 St. Clair to Dawn transportation rate (approximately $0.035/GJ/day currently). These charges will be treated as gas supply costs and recorded in the Union North and Union South Purchased Gas Variance Accounts ("PGVA"'s). The costs will be recovered in gas supply commodity rates, from sales service customers only, as part of Union's QRAM process.

Union estimates that the annual gas supply costs for sales service customers in 2018 associated with St. Clair to Dawn transportation will be approximately $2.0 million (158,258 GJ/d x $0.035/GJ x 365 days). St. Clair to Dawn transportation costs have also been included in the landed cost analysis described in Schedule 4.

In summary, by executing a firm transportation agreement, and therefore supporting the NEXUS project, Union will satisfy all of its Gas Supply Planning principles as follows:

1. Ensuring secure and reliable supply by accessing the most prolific supply basin in North America at a prudently-incurred cost
2. Committing to the NEXUS pipeline, and working with Appalachian suppliers to understand the Ontario market and the benefits of Dawn, will help to ensure the new supply is attracted to Ontario and the required infrastructure gets constructed
3. Replacing existing firm transportation capacity with NEXUS capacity and accessing new secure supplies will assist Union in meeting design day and seasonal gas needs

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

Exhibit B, Tab 1, Schedule 1 Appendix C, pg. 18, para. 38 & p. 20, para. 43

Preamble:

EGI states: *“The Union South in-franchise design day demands at Parkway are allocated to rate classes in proportion to Union South Dawn-Parkway design day demands.”*

Question:

Is are the Union South Dawn-Parkway design day demands distance-weighted?

a) If not, please differentiate what Dawn-Parkway costs are distance-weighted and those that are not.

Response

Enbridge Gas’s cost allocation proposal is to separately classify Parkway Station costs from the Dawn-Parkway Easterly demand transmission functional classification which allocates costs in proportion to Dawn-Parkway distance-weighted design day demands. The proposed Parkway Station demand functional classification uses design day demands that are not distance-weighted. Please see Table 1 for a summary of the Board-approved and proposed cost allocation methodology related to Dawn-Parkway Easterly, Parkway Station, and Dawn Station costs. Please see also Exhibit I.STAFF.2.

Table 1

Board-approved and Proposed Cost Allocation Methodology
Dawn-Parkway and Dawn Station Assets

Description	Board-approved Cost Allocation Methodology	Proposed Cost Allocation Methodology
Dawn-Parkway Transmission		
Dawn-Parkway Easterly Demand Costs excluding Parkway Station	Distance-weighted design day demands	Distance-weighted design day demands
Parkway Station Compressor Costs	Distance-weighted design day demands	Easterly design day demands requiring Parkway compression
Parkway Station Measuring and Regulating Costs	Distance-weighted design day demands	Bi-directional design day demands of the Parkway Station
Other Parkway Station Costs	Distance-weighted design day demands	Parkway Station measuring and measuring and regulating and compressor net plant
Dawn Station		
Dawn Station Compressor Costs	Design day demands requiring Dawn compression	Distance-weighted design day demands
Dawn Station Measuring and Regulating Costs	Distance-weighted design day demands	Design day demands requiring Dawn compression

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

Exhibit B, Tab 2, Schedule 1, pages 20 & 23-27 & EB-2019-0172 References contained in the footnotes below

Preamble:

We want to understand better specifics around additional utilization of the eastern half of the proposed Windsor Line replacement in support of the proposed NPS 6 sizing. From the Leave to Construct proceeding[1]:

When questioned about the need for the enormous levels of surplus capacity, the witnesses provided that there were additional potential customers east of Comber that were not included[2]. We requested that the potential load additions be provided (respecting confidentiality) including the distance east of the T in the intersection north of the Comber Transmission station[3]. What was provided was that there for "four inquiries in the Port Alma and surrounding area"[4]. However, it is disconcerting that the distance from the T in the intersection was not provided. This distance could be provided without any risk to confidentiality. Further, it is very surprising that in the Project Charter approved only a year ahead of this application, in the Key Commercial Drivers Section, while growth benefits are identified for other areas, there is no mention of industrial inquiries in the Port Alma area[5]. We believe these potential load additions require additional scrutiny to establish the appropriate sizing of the pipe.

Question:

Please provide the Project Charter for the Windsor Line.

1 FRPO_REQ ORAL HEARING_20200104
2 TC1 Transcript, Dec. 5, 2019, pg. 48-49
3 TC1 Transcript, Dec. 5, 2019, pg. 51
4 Exhibit JT1.15
5 Exhibit JT1.17, Attachment 2, page 7

Response

Please see Attachment 1 for a copy of the Windsor Line Replacement Project Charter. The Project Charter was also provided in EB-2019-0172 at Exhibit JT1.17, Attachment 2.

1 FRPO_REQ ORAL HEARING_20200104
2 TC1 Transcript, Dec. 5, 2019, pg. 48-49
3 TC1 Transcript, Dec. 5, 2019, pg. 51
4 Exhibit JT1.15
5 Exhibit JT1.17, Attachment 2, page 7

2020 Windsor Line Replacement Project

Project (TBA)

Project Charter

Standard

Document ID:	
Document Owner:	Neil Quenneville

Version #:	1
Version Date:	2018-06-19
Effective Date:	2018-06-19

DOCUMENT VERSION REGISTER

Version #	Version Date [yyyy-mm-dd]	Author / Department	Reviewer / Department	Approved By / Department	Approval Date [yyyy-mm-dd]	• Change Area [Section and Title] ○ Change Description
<#.#>	<yyyy-mm-dd >	<Author>	<Reviewer>	<Approver>	<yyyy-mm-dd >	• <Change Area> ○ <Change Description>

APPROVALS

Position Title / Department	Name	Signature	Date
Project Sponsor	Neil Quenneville		Oct 3, 2018
Asset Performance / Executive Sponsor	Mike Shannon		2018 Oct 03
Project Director	Dave Lamoureux		Oct 3/18
Manager/Director/VP (as applicable)*	Mike Shannon		2018 Oct 03

*Signoff in accordance with ASL

TABLE OF CONTENTS

1 CHARTER OVERVIEW

Project Name:	
Business Development Number	N/A
AFE Number	
Proposed Project In-Service Date	2020-11-01
Project Development Budget	$ 88.0MM
Sponsor	Neil Quenneville
VP – Business Unit	Mike Shannon
Project Leader	Rob Marson
Customer(s)	N/A

2 BUSINESS SCOPE / REQUIREMENTS

This project is a Risk Based Replacement Project. The existing Windsor Line is classified as a Transmission line and it is 1940s vintage. The joining method for the pipe is unrestrained and coupled, with a history of leakage and weldability issues. The limits of this project are from the Sandwich Compressor Station to the Port Alma Station. It will involve laying 64km of pipe and abandoning in place 61.4km.

This project has been deemed a RR2 (L4-C3) from Sandwich to Wheatley Rd 1, and a RR3 (L4C2) from Wheatley Rd 1 to Port Alma.

The following highlight the justification found through engineering assessment:

- This project contains 16 active C-leaks and 3 inoperable mainline valves (Manning, Comber Trans, and Belle River Rd)
- Average capital expenditure of $150,000 to repair the last several B-leaks on this line
- Only able to install top mount fittings on this pipe, but not full encirclement fittings due to pipe condition
- Known sections of exposed/shallow pipe (less than 0.6m)
- Aerial crossings
- Sections of main not in easement
- Unrestrained dresser couplings throughout
- the high likelihood of an incident occurring, large customer impact, high capital expenditure to repair, employee and public safety risks, and integrity concerns.
- The customer impact of the first phase, regardless of degree day, is 167 interruptions.

The new pipeline being installed will be NPS 6 S and test to a maximum operating pressure of 3450 kPa and this will provide an additional capacity up to 40,000 m3/h over the existing line; which will help to continue to serve the growing demands of the greenhouse market. This will be achieved by feeding both directions from Sandwhich Compressor and Port Alma, also a connection at Comber Station at the higher pressure. This will provide the following growth benefits:

- Creates more capacity on the NPS 20 Panhandle to serve the greenhouse market in Kingsville-Leamington
- Creates capacity in the County Rd 46 corridor (close to Hwy 401) for greenhouse/commercial/industrial customers to build their facilities

Should this project be rejected or deferred, one of the many active C-leaks on this line could escalate.

- Results in high out-of-plan capital expenditures to repair, and large customer impacts due to the lacking operable mainline valves on this stretch of pipe

Key assumptions: It is assumed that until corrective action is taken, leaks will continue to develop on this pipe due to the poor condition, limited depth of cover, exposed pipe, aerial crossings, and coupled joints. The key risks include employee, public, and environmental safety.

2.1 Scope Boundaries

This project will include everything to ensure proper operation of the new line from Sandwich Compressor to Port Alma at the 3450 kPa. This will mean feeding stations, lateral take-off stations, HP services with remote first stage cuts, services from first stage cuts to house with meter sets.

2.2 Key Commercial Drivers

The new pipeline being installed should be tested as NPS 6 S 3450 kPa and this will provide excess Capacity up to 40,000 m3/h; which will help to continue to serve the growing demands of the greenhouse market. This will be achieved by feeding both directions from Sandwhich Compressor and Port Alma, also a HP tie in at Comber Station at the higher pressure. This will have the below growth benefits:

- Creates more capacity on the NPS 20 Panhandle to serve the greenhouse market in Kingsville-Leamington
- Creates capacity in the County Rd 46 corridor (close to Hwy 401) for greenhouse/commercial/industrial customers to build their facilities

2.3 Assumptions and Dependencies

The Following is Assumed to be True
It is assumed that until corrective action is taken, leaks will continue to develop on this pipe due to the poor condition, limited depth of cover, exposed pipe, aerial crossings, and coupled joints.
Union Gas will be self performing to complete engineering, procurement, project and construction management
Project will be submitted to the OEB under the ICM for cost recovery

3 FUNDING AUTHORITY

This project is intended to be an ICM submission. The costs required are $5M in 2019 for pre-work, lands etc. The 2020 costs are estimated at ~$100M, at this time.

4 PROJECT SCOPE

This project will include everything to ensure proper operation of the new line from Sandwich Compressor to Port Alma at the 3450 kPa. This will mean feeding stations, lateral take-off stations, ~413 HP services with remote first stage cuts, ~413 services from first stage cuts to house with meter sets

4.1 Pipeline Scope

6" Steel YJ, operating at 3450 kPa. Tie in location on west end is Sandwhich Compressor Station, modifications are required to feed this line with 3450 kPa. Tie in location on East is Port Alma Station, modifications are required to feed this line with 3450 kPa. There are also numerous lateral stations that will need to be rebuilt to handle the new pressure of this line and continue to feed 420 kPa systems with customers.

4.2 Facility Scope

4.2.1 Interconnection

N/A

4.2.2 Pump Station Scope

N/A

4.2.3 Terminal Scope

N/A

4.2.4 Processing Plant Scope

N/A

4.3 Wind Project Scope

N/A

4.4 Solar Farm Scope

N/A

4.5 Alternative Analysis (if available)

Alternative Considered	Reason for Rejecting
NPS 6 S 3450 kPa MOP (Excess Capacity: up to 40,000 m3/h)	Recommended
NPS 8 S 3450 kPa MOP (Excess Capacity: up to 95,000 m3/h)	Cost prohibitive
NPS 6 S 1900 kPa MOP (Excess Capacity: up to 25,000 m3/h)	Value added to utilize 3450kPa for additional capacity at incremental cost
NPS 8 S 1900 kPa MOP (Excess Capacity: up to 56,000 m3/h)	Cost prohibitive
NPS 6 PE 420 kPa MOP (Excess Capacity: up to 2,500 m3/h)	This option would not allow for growth
NPS 4 PE 420 kPa MOP (Excess Capacity: approx. 250 m3/h)	This option would not allow for growth

5 Project Schedule

Activity ID	Activity Name	Start	Finish
MPPROJ-32 Windsor Line Replacement		11-Sep-18	02-Nov-20
MPPROJ-32.1 Project Milestones		11-Sep-18	02-Nov-20
PFU-MIL-1000	Project Start	11-Sep-18	
PFU-MIL-1010	OEB Submission	01-May-19	
PFU-MIL-1020	Long Lead Materials Ordered	19-Nov-19	
PFU-MIL-1030	OEB Approval		31-Dec-19
PFU-MIL-1040	Complete all Land Rights		14-Apr-20
PFU-MIL-1050	Permits Received		14-Apr-20
PFU-MIL-1060	Start Construction	01-May-20	
PFU-MIL-1070	Project In-Service		02-Nov-20

6 PROJECT COST ESTIMATE

This is a class 5 level estimate for the proposed work of abandoning the Existing NPS 10 between Sandwich Compressor and Port Alma and installing a new NPS 6 pipeline.. This includes costs for the service replacements and for station rebuilds and tie-overs. The known scope for this project is conceptual with very limited project parameters provided. For this reason a contingency of 25% has been applied.

Component	Reference Estimate $MM
Management	1.8
Land	1.6
Environment	1.0
Engineering	1.5
Procurement	7.1
Construction	56.6
Total Base Cost Estimate	69.6
Contingency	18.4
Total Project Capital Cost including Escalation	88.0

7 PROJECT RISKS

Category	Constraint
Standards (Government, Industry, other)	CSA Z662 and Ontario Regulation O.Reg 210 will be used to design all facilities.
Engineering and Design	Self performing design
Regulatory	Ontario Energy Board will be the approving Authority
Other (Public Consultation, Land, Environment, Safety, Weather, Geography, Construction, Technology etc.)	Replacement pipeline will be installed in road allowance or easement.

8 APPENDICES

8.1 APPENDIX A: FACILITY REVIEW DOCUMENT

Facility Review Document - Windsor Line.docx

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

Exhibit B, Tab 2, Schedule 1, pages 20 & 23-27 & EB-2019-0172 References contained in the footnotes below

Preamble:

We want to understand better specifics around additional utilization of the eastern half of the proposed Windsor Line replacement in support of the proposed NPS 6 sizing. From the Leave to Construct proceeding[1]:

When questioned about the need for the enormous levels of surplus capacity, the witnesses provided that there were additional potential customers east of Comber that were not included[2]. We requested that the potential load additions be provided (respecting confidentiality) including the distance east of the T in the intersection north of the Comber Transmission station[3]. What was provided was that there for "four inquiries in the Port Alma and surrounding area"[4]. However, it is disconcerting that the distance from the T in the intersection was not provided. This distance could be provided without any risk to confidentiality. Further, it is very surprising that in the Project Charter approved only a year ahead of this application, in the Key Commercial Drivers Section, while growth benefits are identified for other areas, there is no mention of industrial inquiries in the Port Alma area[5]. We believe these potential load additions require additional scrutiny to establish the appropriate sizing of the pipe.

1 FRPO_REQ ORAL HEARING_20200104
2 TC1 Transcript, Dec. 5, 2019, pg. 48-49
3 TC1 Transcript, Dec. 5, 2019, pg. 51
4 Exhibit JT1.15
5 Exhibit JT1.17, Attachment 2, page 7

Question:

Please provide specifics on the customer inquiries for those requested load additions east of the T in the Windsor line north of Comber.

a) Please provide specific emails, service lateral requests, or other documentation in support of assertions of additional interest. Please ensure that the inquiries are differentiated by some notation such as, Customer A, Customer B, etc. to distinguish individual inquiries from multiple inquiries from the same customer

   i. For each of the individual inquiry, please provide the distance from the T in the Windsor Line north of the Comber Station.
   ii. Please provide the hourly load associated with the individual inquiry.

b) Have any inquiries been attached to the system?

   i. If so, what hourly load was applied for?

      1. Using that load, what is the remaining surplus capacity at Port Alma using the criteria analyzed and reported in EB-2019-0172 Ex. KT1.2?

c) Are any inquiries in active process with a scheduled installation in 2020?

   i. If so, what hourly load was applied for?

      1. Using that load, in addition to what was added in b), what is the remaining surplus capacity at Port Alma using the criteria analyzed and reported in EB-2019-0172 Ex. KT1.2?

d) Was any aid-to-construction calculated for any of the load inquiries?

e) What would the revenue requirement impact be for each of those potential customers?

   i. How did or does it affect the ICM request by the company?

1 FRPO_REQ ORAL HEARING_20200104
2 TC1 Transcript, Dec. 5, 2019, pg. 48-49
3 TC1 Transcript, Dec. 5, 2019, pg. 51
4 Exhibit JT1.15
5 Exhibit JT1.17, Attachment 2, page 7

Response

The requested information in part a) to d) is not relevant to the relief being sought in this proceeding. However, to the extent the information can provide further clarity to the Board, a response is provided below.

a) An overview of the distribution lines in the Port Alma area and the customer inquiries (redacted) can be found in the following attachments:

- Attachment 1: Port Alma Station
- Attachment 2: Customer A inquiry
- Attachment 3: Customer B inquiry
- Attachment 4: Customer C inquiry
- Attachment 5: Customer D inquiry
- Attachment 6: Customer E inquiry

The customer inquiries were east of Comber, and not directly on the Windsor Line. The customer inquiries illustrate the demand that Enbridge Gas has been receiving since the FBP. The inquiries predominantly stem from greenhouses and Enbridge Gas anticipates it will continue to receive requests from similar customers in the future. These requests are on pipelines in the area surrounding Port Alma Station that can be supported by the Windsor Line as shown in the diagram in Attachment 1. The approximate distances of each customer A through E from Port Alma Station are 23 km, 8 km, 2.3 km, 2.2 km and 8.4 km.

b) Yes, one of the four inquiries (Customer B) proceeded in 2019.

i) 2600 m3/hr

1) The surplus capacity of the Windsor Line did not change as this load already proceeded before the analysis in EB-2019-0172, Exhibit KT1.2, and was reserved on the existing Leamington Line that did not require flow support from the Windsor Line through Port Alma Station for attachment. The consequence of adding this load restricts the capacity of the surrounding pipelines (as shown in Attachment 1) and impairs the ability to serve the types of greenhouse customer requests that Enbridge Gas has been receiving.

1 FRPO_REQ ORAL HEARING_20200104
2 TC1 Transcript, Dec. 5, 2019, pg. 48-49
3 TC1 Transcript, Dec. 5, 2019, pg. 51
4 Exhibit JT1.15
5 Exhibit JT1.17, Attachment 2, page 7

c) The remaining three other inquiries (Customers A,C and D) are not scheduled for installation in 2020 at this time. Also an additional inquiry by a single customer (Customer E) was requested in 2020 to the south of Port Alma (along the Leamington Line). Although there is no guarantee all unforecasted loads will proceed, the greenhouse requests are indicative of the type/size of requests Enbridge Gas is receiving in the Port Alma area. The NPS 6 design for the Windsor Line will help support these potential customers and minimize the potential for local reinforcement of the surrounding pipelines.

i) 2,750 m3/hr (Customer E)

1. A large load of 2,750 m3/hr to the system south of Port Alma would currently cause reinforcement without the Windsor Line replacement at the 3450 kPa MOP. With the Windsor Line replacement, additional pressure and flow through Port Alma station would currently remove reinforcement for this customer. If the NPS 4 option is installed east of Comber Transmission, approximately half the surplus capacity on the Windsor Line would be removed at Port Alma with this load addition. If the recommended option of NPS 6 is installed, several additional large customers can likely be attached and supported by the Windsor Line and flow through the Port Alma Station without significant reinforcement downstream. In other words, the other pipelines in the area cannot readily support large customers any further at this time without reinforcement, and the Windsor Line replacement will support growth in the area through Port Alma Station.

   Knowing that the Windsor Line must be replaced due to the Integrity concerns and the age of the pipeline, it is both efficient and prudent to maintain the existing capacity of the Windsor Line to support unforecasted growth in the Port Alma area and defer potential reinforcements that may be required due to unforecasted growth.

   It is important to note that the total loads of all inquiries requested in this area would not be able to be supported by the Windsor Line through Port Alma Station if NPS 4 option is installed east of Comber Transmission Station. This is an example of the sizes and amount of requests that are unforecasted in the area and will likely be requested ongoing in the future showing the need for the NPS 6 pipeline.

1 FRPO_REQ ORAL HEARING_20200104
2 TC1 Transcript, Dec. 5, 2019, pg. 48-49
3 TC1 Transcript, Dec. 5, 2019, pg. 51
4 Exhibit JT1.15
5 Exhibit JT1.17, Attachment 2, page 7

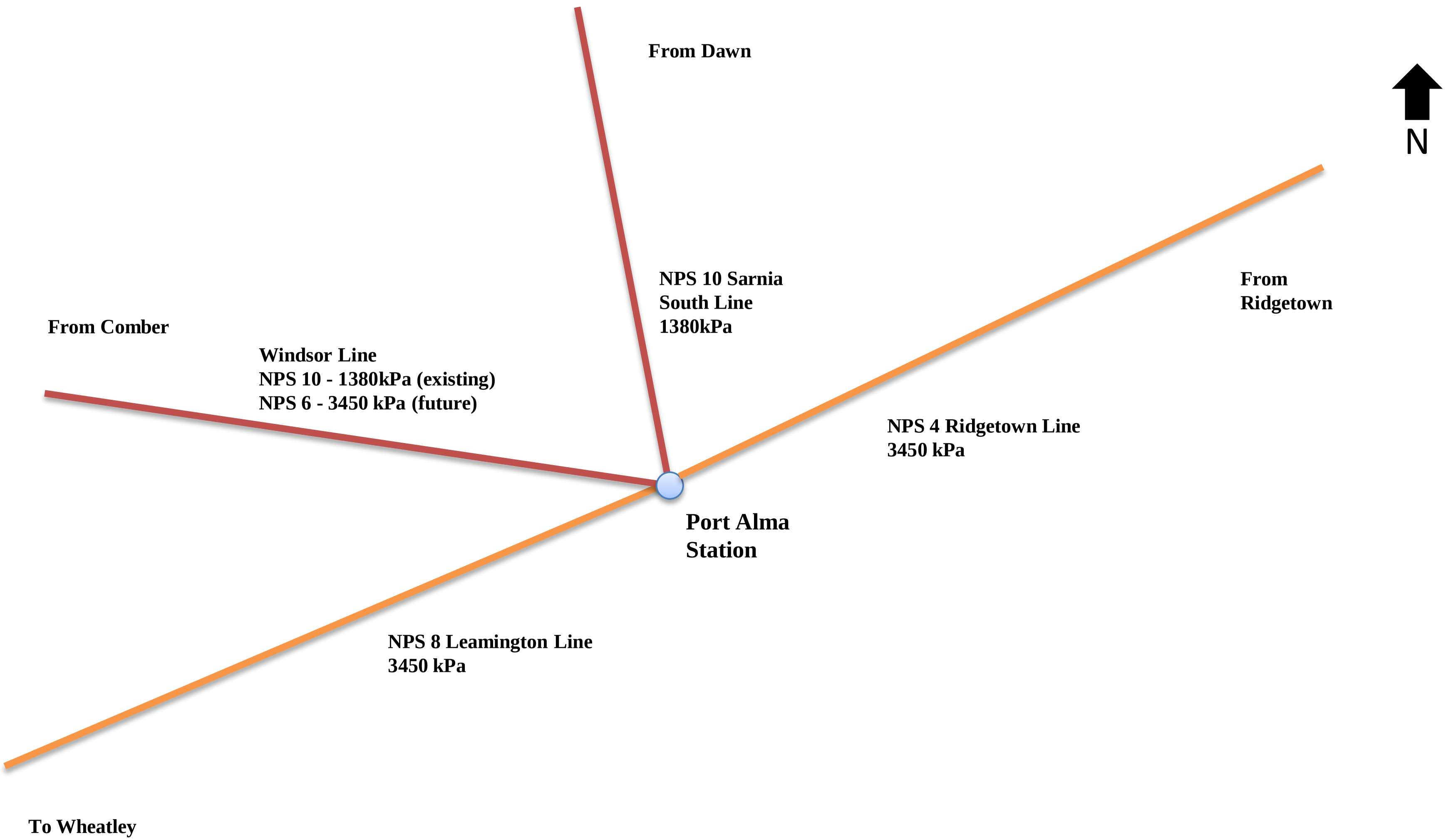
d) Customer B did not require aid-to construct as the existing system had adequate capacity. The remaining inquiries are under assessment and any aid-to-construct will be determined as Enbridge moves through the load attachment process.

e) There is no revenue requirement impact resulting from any potential customers.

   i) There is no impact on the ICM request.

1 FRPO_REQ ORAL HEARING_20200104
2 TC1 Transcript, Dec. 5, 2019, pg. 48-49
3 TC1 Transcript, Dec. 5, 2019, pg. 51
4 Exhibit JT1.15
5 Exhibit JT1.17, Attachment 2, page 7

PORT ALMA STATION – OVERVIEW



From: [redacted]
To: [redacted]
Subject: FW: Gas Availability Enquiry
Date: November-28-19 4:14:33 PM

[redacted], I have a customer interested in purchasing a property in [redacted] and build four phases of 20 acers of greenhouse totaling 80 acers. Is there any capacity to support 1800m3/hour per phase?

Thanks,

[redacted], BHSc, MBA Candidate
Account Manager
Large Commercial Industrial Accounts, Distribution In-Franchise Sales
—
ENBRIDGE
TEL: 519-436-4658 | CELL: 226-229-0932 | [redacted]@enbridge.com
50 Keil Drive, N. Chatham, ON N7M 5M1
enbridge.com
Safety. Integrity. Respect.

Contract Sales - C&G Project:

PROJECT INITIATION FORM

Date: February-06-18

Account Manager: [redacted]

Type of Estimate Required:

- ○ Feasibility Estimate (+40%/-25%) - 3 weeks* for feasibility estimate and timelines
  - *To be completed for:*
  - *- "tire kickers" (i.e. no defined location or pursuring multiple equipment options)*
  - *- customers that are not likely to proceed within 1 year*
  - *- if reinforcement is required to attach customer (if unknown if reinforcement is req'd, a request for budget estimate can be completed, but will be given a feasibility estimate first).*
  - **Projects involving large or multiple stations, transmission line taps, or major reinforcement may require more time. If this is the case, you will be notified within 2 weeks of request of the increased time requirements.*
- ◉ Budget Estimate (+15%/-10%) - 6-8 weeks* for budget estimate and timelines
  - *To be completed for:*
  - *- customers that have a defined location and have clearly identified energy requirements*
  - *- customers that are likely to proceed within 1 year*
  - **Projects involving large or multiple stations, transmission line taps, or major reinforcement may require more time. If this is the case, you will be notified within 2 weeks of request of the increased time requirements.*
  - **If Feasibility Estimate has already been completed, Budget Estimate timing may be reduced (discuss with District Engineer)*

Type of Request:

- ○ New customer *(Fill in all blue and green fields)*
- ○ Existing customer - New Service *(Fill in all blue and green fields)*
- ◉ Existing Customer - Parameter Changes *(Fill in all blue and red fields)*
- ○ Other:

Name of customer: [redacted]

Type of customer (industry, greenhouse, etc.): [redacted]

Location of customer: [redacted]
(Address, Town/City, Postal Code)

Customer contact info - for site access:

Name	[redacted]		
Phone	[redacted]	Fax	
Email	[redacted]		

Customer contact info - for technical info (☑ same as above):

Name			
Phone		Fax	
Email			

X-Y Coordinates of customer:

How To

Lat. (+ve decimal):	[redacted]
Long. (+ve decimal):	[redacted]

Coordinates for Gnetviewer: [redacted]

If existing UG Customer, Account # and/or Meter # and/or Station #: [redacted]

Requested In-Service Date: October-01-19

Load Requirements

n

Note: ensure this information is correct. Changing this data starts the process over.	Existing	New (Incremental)	Total (Existing + New)	Potential Future (Existing + New + Future)	Year
Contracted (Diversified) Max Hourly Firm Flow (m3/hr):	2540	2600	5140		
Contracted (Diversified) Max Hourly Interruptible Flow (m3/hr):			0		
Low Flow, if known (m3/hr): *- if there will be a situation where major equipment is not running, but gas will still be req'd (i.e. office heating running off of same station as process load)*					
Connected Load (New + Existing), if known (m3/hr):	2540				
Greenhouse Acres	33.5				
Annual Volume (m3/year):					

Requested equipment list? ☐ Yes, see Sharepoint for list ☐ Yes, see list below ☐ Yes, but not available at this time

Requested delivery pressure after meter (1.75, 14, 35, 70kPa or other): 70 kPa Current pressure: 70 kPa

Length of service (from property line) or attach site plan w/scale and location identified: 100 m ← THIS IS A REQUIREMENT

From: [redacted]
Sent: Tuesday, June 05, 2018 10:39 AM
To: [redacted]
Subject: New Workbook - [redacted]

Good Morning!

I've created a new workbook for [redacted] replacing one that is now cancelled under [redacted]. The original feasibility estimate was for a GH in 2 phases of 60 (5,400 m3/hr each phase) acres and due to the extensive reinforcement required the cost came in at $4.4 million. The property owner has scaled their request back significantly (1 phase 1,350 m3/hr) with a requested in-service date of Nov 1, 2019.

[redacted]

Let me know if you have any questions – thanks!

[redacted]
Sr Advisor, Greenhouse Accounts
Union Gas Limited | An Enbridge Company
TEL: 519-436-4676 | CELL: 519-350-2570 | FAX: 519-436-4645 | [redacted]@uniongas.com
50 Keil Drive | Chatham, ON N7M 5M1
uniongas.com | Canada's Top 100 Employer | Facebook | Twitter | LinkedIn | YouTube

Contract Sales - C&G Project:

PROJECT INITIATION FORM

Date: November-12-19

Account Manager: [redacted]

Type of Estimate Required:

- (●) Feasibility Estimate (+40%/-25%) - 3 weeks* for feasibility estimate and timelines

  To be completed for:
  - *"tire kickers" (i.e. no defined location or pursuring multiple equipment options)*
  - *customers that are not likely to proceed within 1 year*
  - *if reinforcement is required to attach customer (if unknown if reinforcement is req'd, a request for budget estimate can be completed, but will be given a feasibility estimate first).*

  **Projects involving large or multiple stations, transmission line taps, or major reinforcement may require more time. If this is the case, you will be notified within 2 weeks of request of the increased time requirements.*

- ( ) Budget Estimate (+15%/-10%) - 6-8 weeks* for budget estimate and timelines

  To be completed for:
  - *customers that have a defined location and have clearly identified energy requirements*
  - *customers that are likely to proceed within 1 year*

  **Projects involving large or multiple stations, transmission line taps, or major reinforcement may require more time. If this is the case, you will be notified within 2 weeks of request of the increased time requirements.*
  **If Feasibility Estimate has already been completed, Budget Estimate timing may be reduced (discuss with District Engineer)*

Type of Request:

- (●) New customer *(Fill in all blue and green fields)*
- ( ) Existing customer - New Service *(Fill in all blue and green fields)*
- ( ) Existing Customer - Parameter Changes *(Fill in all blue and red fields)*
- ( ) Other:

Name of customer: [redacted]

Type of customer (industry, greenhouse, etc.): [redacted]

Location of customer: [redacted]
(Address, Town/City, Postal Code)

Customer contact info - for site access:

Name	[redacted]		
Phone	[redacted]	Fax	
Email	[redacted]		

Customer contact info - for technical info (☑ same as above):

Name			
Phone		Fax	
Email			

X-Y Coordinates of customer:
How To

Lat. (+ve decimal):	[redacted]
Long. (+ve decimal):	[redacted]

Coordinates for Gnetviewer: [redacted]

If existing UG Customer, Account # and/or Meter # and/or Station #:

New	New	New

Requested In-Service Date: November-01-20

Load Requirements

n

Note: ensure this information is correct. Changing this data starts the process over.	Existing	New (Incremental)	Total (Existing + New)	Potential Future (Existing + New + Future)	Year
Contracted (Diversified) Max Hourly Firm Flow (m3/hr):		2250	2250	9000	2020-2027
Contracted (Diversified) Max Hourly Interruptible Flow (m3/hr):			0		

Low Flow, if known (m3/hr): *- if there will be a situation where major equipment is not running, but gas will still be req'd (i.e. office heating running off of same station as process load)*	
Connected Load (New + Existing), if known (m3/hr):	
Greenhouse Acres	25
Annual Volume (m3/year):	4000000

Requested equipment list? ☐ Yes, see Sharepoint for list ☐ Yes, see list below ☐ Yes, but not available at this time

Requested delivery pressure after meter (1.75, 14, 35, 70kPa or other): 70 kPa Current pressure: kPa

Length of service (from property line) or attach site plan w/scale and location identified: 100 m ← THIS IS A REQUIREMENT

Contract Sales - C&G Project:

PROJECT INITIATION FORM

Date: February-04-20

Account Manager: [redacted]

Type of Estimate Required:

(●) Feasibility Estimate (+40%/-25%) - 3 weeks* for feasibility estimate and timelines

To be completed for:
- *"tire kickers" (i.e. no defined location or pursuing multiple equipment options)*
- *customers that are not likely to proceed within 1 year*
- *if reinforcement is required to attach customer (if unknown if reinforcement is req'd, a request for budget estimate can be completed, but will be given a feasibility estimate first).*

**Projects involving large or multiple stations, transmission line taps, or major reinforcement may require more time. If this is the case, you will be notified within 2 weeks of request of the increased time requirements.*

( ) Budget Estimate (+15%/-10%) - 6-8 weeks* for budget estimate and timelines

To be completed for:
- *customers that have a defined location and have clearly identified energy requirements*
- *customers that are likely to proceed within 1 year*

**Projects involving large or multiple stations, transmission line taps, or major reinforcement may require more time. If this is the case, you will be notified within 2 weeks of request of the increased time requirements.*

**If Feasibility Estimate has already been completed, Budget Estimate timing may be reduced (discuss with District Engineer)*

Type of Request:

(●) New customer *(Fill in all blue and green fields)*

( ) Existing customer - New Service *(Fill in all blue and green fields)*

( ) Existing Customer - Parameter Changes *(Fill in all blue and red fields)*

( ) Other:

Name of customer: [redacted]

Type of customer (industry, greenhouse, etc.): [redacted]

Location of customer: [redacted]

(Address, Town/City, Postal Code)

Customer contact info - for site access:

Name	[redacted]		
Phone	[redacted]	Fax	
Email	[redacted]		

Customer contact info - for technical info (☑ same as above):

Name			
Phone		Fax	
Email			

X-Y Coordinates of customer:

How To

Lat. (+ve decimal):	[redacted]
Long. (+ve decimal):	[redacted]

Coordinates for Gnetviewer: [redacted]

If existing UG Customer, Account # and/or Meter # and/or Station #:

New	New	New

Requested In-Service Date: December-01-22

Load Requirements

Note: ensure this information is correct. Changing this data starts the process over.	Existing	New (Incremental)	Total (Existing + New)	Potential Future (Existing + New + Future)	Year
Contracted (Diversified) Max Hourly Firm Flow (m3/hr):		2750	2750	5500	2024
Contracted (Diversified) Max Hourly Interruptible Flow (m3/hr):			0		
Low Flow, if known (m3/hr): *- if there will be a situation where major equipment is not running, but gas will still be req'd (i.e. office heating running off of same station as process load)*					
Connected Load (New + Existing), if known (m3/hr):	0				
Greenhouse Acres	34+34				
Annual Volume (m3/year):	5,750,000				

Requested equipment ist? ☐ Yes, see Sharepoint for list ☐ Yes, see list below ☐ Yes, but not available at this time

Requested delivery pressure after meter (1.75, 14, 35, 70kPa or other): 70 kPa Current pressure: kPa

Length of service (from property line) or attach site plan w/scale and location identified: 150 m ← THIS IS A REQUIREMENT

ENBRIDGE GAS INC.

Answer to Interrogatory from
Industrial Gas Users Association ("IGUA")

Interrogatory

Reference:

a) ExB/T1/S1/p3. EG is not proposing to change rates to adopt its cost allocation proposal until rebasing of rates for January 1, 2024 (i.e. 4 years from now).

b) ExB/T1/S1/AppC/p10/paragraph 19. EB-2016-0186; Panhandle Reinforcement Project Application

Preamble:

In 2016 (then) Union Gas proposed to change cost allocation for the Panhandle and St. Clair systems to better reflect costs to serve customers on their respective parts of these Systems once the Panhandle Reinforcement Project was put into service. These changes would have been implemented for the period prior to Union's next anticipated rebasing for January 1, 2019 (approximately 14 months - see February 23, 2017 Decision and Order, page 11, first full paragraph).

Question:

a) Please confirm that at the time of the EB-2016-0186 Panhandle Reinforcement Project Application Union anticipated that a full cost allocation study would be prepared in support of an application in 2018 to rebase rates for January 1, 2019.

b) Please confirm that a full cost allocation study for rebasing of rates would have been expected to result in cost allocation changes beyond those proposed in EB-2016-0186.

c) Please confirm that Union's proposal in 2016 was to update rates to reflect a revised Panhandle and St. Clair systems cost allocation, in advance of the full cost allocation study then anticipated to be completed for rebasing effective January 1, 2019 and despite the expectation that the future full cost allocation study would have resulted in additional changes.

d) Please explain what has changed between the time that Union proposed in 2016 to immediately implement rate changes to better reflect costs to serve customers on the reinforced Panhandle system and customers on the St. Clair system, and now, that has led EG to conclude that it is appropriate to retain the current, less cost reflective, cost allocation in rates for another 4 years. Please explain specifically how EG's current situation is different from Union's situation in 2016 such that Union's proposal to change rates immediately to better reflect costs to serve Panhandle and St. Clair System dependant customers is not appropriate today.

Response

a) Confirmed.

b) Confirmed.

c) Not confirmed. Union's proposal in the Panhandle Reinforcement Project application (EB-2016-0186) was for Board approval of an interim allocation of the Project related costs only during the remainder of the IRM term. Union did not propose a revised cost allocation for all of Panhandle and St. Clair System costs in the application and proposed to continue with the allocation of existing Panhandle System and St. Clair System costs from 2013. Enbridge Gas does confirm that a future cost allocation study may have resulted in additional changes to those proposed in the EB-2016-0186 application.

d) In 2016, Union anticipated that the Company would rebase in 2019 and as part of that proceeding, any proposed rate changes would incorporate a full cost of service review by all parties. The Board found in EB-2016-0186 that Union's proposal should be deferred to the next cost of service or custom IR application[1].

Since 2016, Union and Enbridge Gas Distribution have amalgamated and the Company's current approved rate setting mechanism is a price cap which provides stability to rates during the deferred rebasing period but also results in rates that are decoupled from costs. Implementing the cost allocation study results in rates before rebasing will result in rate increases for some rate classes and rate decreases for other rate classes which reduces the rate stability expected by customers. The Company also anticipates there will be additional changes to rates at rebasing in 2024 when Enbridge Gas introduces rate harmonization, integration of the cost

[1] EB-2016-0186 Decision and Order, February 23, 2017, pp. 10-11.

allocation studies of the combined utilities and the pass-through of synergy cost savings into rates. Please see Exhibit I.STAFF.4 part b).

Recognizing the concerns with the approved cost allocation methodology for Panhandle and St. Clair System costs, Enbridge Gas has proposed a change to the allocation of Panhandle and St. Clair System costs for approval as part of this proceeding to be implemented in rates at the time of the next rebasing in 2024.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Industrial Gas Users Association ("IGUA")

Interrogatory

Reference:

ExB/T1/S1/AppC/p.9/Table 2. The evidence summarizes the aggregate dollar impact, by rate class, of the Cost Study Proposals.

Question:

a) Please provide the annual distribution rate impact, by rate class, if 2020 rates were to be updated to reflect the impact of the Cost Study Proposals evidenced.

b) Please provide the annual distribution cost impact for a typical customer in each of EG's rate classes if 2020 rates were to be updated to reflect the impact of the Cost Study Proposals evidenced.

c) Please provide the volume assumptions used for each "typical customer" in deriving the cost impacts provided in response to part (b).

Response

a to c)

Please see Exhibit I.STAFF.4 part c) for the estimated in-franchise bill impacts associated with the cost allocation study results, including Rate M4. Exhibit I.STAFF.4, Attachment 1 provides bill impacts including the cost allocation proposals, Attachment 2 provides bill impacts excluding the cost allocation proposals, and Attachment 4 provides the parameters used to calculate the bill impacts for each rate class.

Please see Exhibit I.SEC.8 for the EGD rate zone customer impacts.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Industrial Gas Users Association ("IGUA")

Interrogatory

Reference:

ExB/T1/S1/AppC/p10/paragraph 20. The evidence describes the way that the St. Clair and Panhandle Systems are used.

Question:

Please file a map which illustrates the use of the St. Clair and Panhandle Systems as described in the evidence.

Response

Please see Exhibit I.APPrO.1.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Industrial Gas Users Association ("IGUA")

Interrogatory

Reference:

ExB/T1/S1/AppC/p12/para. 23. The evidence explains that with the inclusion of significant costs to the Panhandle System only as a result of the Panhandle Reinforcement Project, the use of the Ojibway/St. Clair demand allocation methodology no longer reflects the costs to serve customers on each of the respective systems.

Question:

Please provide the costs (as of 2019) for each of the Panhandle and St. Clair systems.

Response

The estimated 2019 revenue requirement of the Panhandle System is $38.195 million.[1]

The estimated 2019 revenue requirement of the St. Clair System is $2.250 million.[2]

[1] Exhibit B, Tab 1, Appendix C, Working Papers, Schedule 2, p. 1, column (k).
[2] Exhibit B, Tab 1, Appendix C, Working Papers, Schedule 2, p. 1, column (j).

ENBRIDGE GAS INC.

Answer to Interrogatory from
Industrial Gas Users Association ("IGUA")

Interrogatory

Reference:

ExB/T1/S1/AppC/pp.12-15; EB-2017-0087, Exhibit B.IGUA.4, page 3, Table 1. The evidence in this proceeding discusses the demand functional classification used in Cost Study Proposal. The evidence referenced from EB-2017-0087 presents information on design day demands on each of the Panhandle and St. Clair systems.

Question:

Please provide a table that compares the St. Clair and Panhandle System Design Day Demand percentages allocated to each rate class in;

a) the Cost Study Proposal prepared for this proceeding; and

b) the OEB approved cost allocation methodology.

Please use the following column headings in the table:

(i) Rate Class;

(ii) Cost Study Proposal Design Day Demands – St. Clair System;

(iii) Cost Study Proposal Design Day Demands – Panhandle System;

(iv) OEB Approved Cost Allocation Design Day Demands; and

(v) Difference (column (iii) – column (iv)).

Response

Please see Attachment 1.

UNION RATE ZONES
Comparison of St. Clair and Panhandle System Design Day Demand Percentages

Line No.	Rate Class	Cost Study Proposal Design Day Demands - St. Clair System (1)	Cost Study Proposal Design Day Demands - Panhandle System	OEB Approved Cost Allocation Design Day Demands	Difference
		(a)	(b)	(c)	(d) = (b-c)
	Union South				
1	Rate M1	-	32.6%	14.0%	18.7%
2	Rate M2	-	11.1%	4.8%	6.4%
3	Rate M4	-	21.3%	7.8%	13.5%
4	Rate M5	-	0.1%	0.0%	0.1%
5	Rate M7	-	6.9%	2.6%	4.3%
6	Rate T1	-	4.5%	2.1%	2.4%
7	Rate T2	-	23.5%	32.7%	-9.2%
8	Total Union South	-	100.0%	63.9%	36.1%
	Ex-Franchise				
9	Rate C1	100.0%	-	33.3%	-33.3%
10	Rate M16	-	-	2.7%	-2.7%
11	Total Ex-Franchise	100.0%	-	36.1%	-36.1%
12	Total	100.0%	100.0%	100.0%	-

Notes:
(1) The proposed allocation of St. Clair System demand costs direct assigns all costs to Rate C1.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Industrial Gas Users Association ("IGUA")

Interrogatory

Reference:

ExB/T1/S1/AppC/p30/paragraph 66. EG has suggested that implementing any cost allocation changes directed could be done as part of setting 2021 rates, which would *"allow time for all appropriate adjustments to be calculated and explained and approved.*

Question:

a) Please detail the adjustments, calculations and explanations that in EG's view would be required to implement cost allocation changes directed, including the time required for each of these activities.

b) Could changes directed be implemented with EG's July or October 2020 QRAMs? If not, why not?

Response

a) In order to implement the cost allocation study results in rates, Enbridge Gas requires a Board-approved rate order incorporating the unit rate changes resulting from the directive. The unit rate changes provided at Exhibit I.STAFF.4 part c) were prepared for illustration of the estimated in-franchise bill impacts but do not include rate design considerations that will need to be factored into a final rate order. Exhibit I.TCPL.1 part d) provides a list of rate design considerations that are used when proposing final rates.

   It is imperative that rate design adjustments be factored into the final unit rate changes from the cost allocation study, otherwise the impacts of the rate design adjustments approved by the Board as part of the 2013 Cost of Service proceeding (EB-2011-0210) will be unwound in the final unit rates implemented with the directive. Unit rates without rate design adjustments may result in unintended impacts to customers and the Company absent a complete rate design review similar to what is completed as part of a cost of service proceeding.

Further, if the cost allocation study results are to be implemented in rates, consideration will need to be made as to whether there are corresponding impacts on base amounts used in current approved deferral and variance account calculations. Certain deferral and variance accounts for the Union rate zone use the revenue requirement in rates as the base to calculate the deferral balance. As such, implementation of the cost allocation study results will require an assessment to determine if it impacts the revenue requirements in rates, and as a result, the calculation of certain deferral and variance account balances.

If directed by the Board to implement the cost allocation study results in rates, Enbridge Gas will calculate unit rate changes for each rate class and rate component based on the revenue sufficiency / deficiency from the cost allocation study results, including rate design considerations, and the 2019 forecast used in the cost allocation study. The unit rate changes will be added or deducted from the unit rates calculated using the approved rate setting mechanism for the remainder of the deferred rebasing period.

To ensure the cost allocation study changes are made on a revenue neutral basis, the effective date of the rate change must be January 1, because the unit rates are calculated based on an annual forecast.

Enbridge Gas estimates it will require approximately three months following the Board's direction in this proceeding to file a draft rate order incorporating the cost allocation study results including a proposal for adjustments to the unit rates for rate design factors. The Company expects the draft rate order submission will also include a proposal for any adjustments to the base amount used to calculate deferral and variance accounts for consideration at the same time. Enbridge Gas estimates approximately one month will be required to provide for comments from Board staff and intervenors on the draft rate order and proposal for deferral and variance accounts followed by a response from the Company. A final decision from the Board on the draft rate order will follow. If adjustments are required from the unit rate changes proposed by Enbridge Gas following the Board's decision, the Company estimates it will require up to three weeks to incorporate the adjustments in the final rate order for approval. In order to implement the final rate order with a QRAM proceeding, the Company requires approval of the final rate order from this proceeding one month in advance of the QRAM implementation date. Enbridge Gas estimates the process of a final rate order could take up to six months once the Board provides direction in this proceeding until the Company could implement in rates with a QRAM.

b) No, Enbridge Gas does not believe implementation with the July 2020 or October 2020 QRAM is possible based on the estimate of time to receive an approved final rate order in this proceeding as described in part a).

Based on the estimated timeline to receive a final rate order in this proceeding and the need to implement rates with an effective date of January 1 to ensure revenue neutrality (as described above), if the Board directed an update to rates as a result of the cost allocation results, Enbridge Gas recommends that the unit rate changes be implemented on a prospective basis no earlier than with 2021 Rates effective January 1, 2021.

ENBRIDGE GAS INC.

Answer to Interrogatory from
City of Kitchener ("Kitchener")

Interrogatory

Reference:

Ex. B, Tab 1, App. C, Working Papers, Sch. 5, pg. 12 &13 line 14, pg. 14 line 13
EB-2011-0210 Union_Exhibit G_Updated_20120713
EB-2011-0210 Union_Exhibit H_Updated_20120713

Preamble:

We would like to understand the underlying drivers and methodologies that contribute to the seeming disparity in the proportionality of the Monthly Charges in EGI's semi-unbundled rate classes.

Question:

Using the cost allocation and ratemaking evidence from the last Union Gas rebasing proceeding, for the T1, T2 and T3 rate classes, please provide:

a) A specific description of the drivers for each of the allocators of the customer related costs that contribute to the build-up of the Monthly Charges for each of the rate classes.

b) By way of an Excel spreadsheet, please extract from rebasing proceeding Exhibits, the data and formulae that build up the total customer-related costs that contribute to the Monthly Charge for each of the rate classes.

c) Please explain any significant differences in the allocation of costs to reflect the T3 rate classes characteristic as a wholesale distributor who owns its own distribution system.

d) Please explain how the number of units for each rate class in column a) contribute to the proportionality of costs allocated.

e) Please provide an electronic copy of the working spreadsheet that provides the costs and the allocation formulae

Response

Enbridge Gas does not believe that the premise of these questions (taken from the Preamble) is relevant to the outstanding issues in this proceeding. However, Enbridge Gas is prepared to provide a response for information purposes.

a) Please see Attachment 1.

b) Please see Attachment 2.

c) Rate T3 is allocated distribution costs related to their connection to Enbridge Gas's system, such as their station facilities and the operating costs for their monthly billing and sales representatives. As a wholesale distributor, Rate T3 does not utilize the Enbridge Gas distribution system and is not allocated other distribution costs, such as mains and services.

d) The forecast usage in column a)[1] represents the forecast total number of 2019 monthly bills for each rate class used to determine the current approved revenue. The number of monthly bills are not used in the cost allocation study to allocate costs to rate classes.

e) Enbridge Gas filed the 2019 cost allocation study in Excel format on February 7, 2020. Please see Exhibit B, Tab 1, Appendix C1, Schedule 5.23, Column S, U, and W for the allocation of costs to Distribution Customer from the 2019 cost allocation study.

[1] Exhibit B, Tab 1, Appendix C, Working Papers, Schedule 5, p.12 &13, line 14 & p.14, line 13.

UNION RATE ZONES
Derivation of 2013 Rate T1, Rate T2 and Rate T3 Monthly Customer Charge

Line No.	Particulars ($000's)	Direct Assigment Factor (1)	Allocation Factor (1)	Allocated Costs: Firm Rate T1	Allocated Costs: Firm Rate T2	Allocated Costs: Rate T3
		(a)	(b)	(c)	(d)	(e)
	Rate Base					
	Gross Plant in Service					
	Distribution					
1	Land, Land Rights, Structures & Improvements		S_CUSTMM&RCOM	89	1,260	-
2	Mains, Services		SERVREPLCOSTS	2,256	31,953	-
3	Meters, Regulators, Customer Stations		STATIONREPLCOSTS	1,742	9,102	1,115
4	Intangible Plant		INDIR_I_DIST	7	73	2
5	General Plant		INDIR_I&II_DIST	282	1,453	68
6	Total Gross Plant in Service			4,376	43,840	1,185
	Accumulated Depreciation					
	Distribution					
7	Land Rights, Structures & Improvements		S_CUSTMM&RCOM	25	348	-
8	Mains, Services		SERVREPLCOSTS	1,022	14,471	-
9	Meters, Regulators, Customer Stations		STATIONREPLCOSTS	654	3,417	419
10	Intangible Plant		INDIR_I_DIST	6	59	2
11	General Plant		INDIR_I&II_DIST	130	671	32
12	Total Accumulated Depreciation			1,836	18,965	452
	Working Capital					
13	O&M Working Capital		INDIR_II_DIST	31	73	7
14	Other Working Capital		INDIR_I_DIST	(31)	(315)	(9)
15	Total Working Capital			0	(243)	(2)
16	Accumulated Deferred Taxes		S_DISTBASE-3	(42)	(409)	(12)
17	Total Rate Base (line 6 - line 12 + line 15 + line 16)			2,498	24,223	719

Notes:
(1) A description of direct assignment and allocation factors is provided at EB-2011-0210, Exhibit G3, Tab 1, Schedule 1, Appendix C.

UNION RATE ZONES
Derivation of 2013 Rate T1, Rate T2 and Rate T3 Monthly Customer Charge

Line No.	Particulars ($000's)	Direct Assigment Factor (1)	Allocation Factor (1)	Allocated Costs Firm Rate T1	Firm Rate T2	Rate T3
		(a)	(b)	(c)	(d)	(e)
	Revenue Requirement					
18	Return on Rate Base (7.32% * Rate Base)			183	1,773	53
19	Income Taxes		DISTBASE-3	21	206	6
20	Property Tax		DISTPROTAX-3	24	338	0
21	Accumulated Deferred Tax Drawdown		S_DISTBASE-3	(9)	(89)	(3)
	Depreciation Expense					
22	Distribution Plant			126	1,195	42
23	Intangible Plant			0	2	0
24	General Plant			38	195	9
	Operating & Maintenance Expense					
25	Distribution Mains		SERVREPLCOSTS	25	361	-
26	Distribution Meter & Regulator Repair		S_CUSTM&RXRES	15	79	10
27	General Operating & Engineering		DISTCUSTPT	28	285	8
28	Sales Supervision	M9/T3ALLO		-	-	53
29	Sales Supervision		DCUSTSALEPRO	237	49	0
30	Sales Other		DCUSTSALEOTHER	18	4	-
31	Distribution Customer Accounting Customer Billing	LRGINDBILLS		-	-	1
32	Distribution Customer Accounting Customer Billing		AVECUST	6	45	0
33	Distribution Customer Accounting Uncollectible Accounts		BDEBTDIST	16	2	0
34	Administrative & General Employee Benefits		DISTLABOR-3	114	228	26
35	Administrative & General Other		DISTO&MEXP-3	180	430	38
36	Total Distribution Customer Revenue Requirement (sum of lines 18 to 35) (2)			1,022	5,104	244

Notes:
(1) A description of direct assignment and allocation factors is provided at EB-2011-0210, Exhibit G3, Tab 1, Schedule 1, Appendix C.
(2) EB-2011-0210, Exhibit G3, Tab 2, Schedule 1, p.2, Updated per EB-2013-0365 Settlement Agreement.

UNION RATE ZONES

Derivation of 2013 Rate T1, Rate T2 and Rate T3 Monthly Customer Charge

Line No.	Particulars ($000's)	Rate T1 (1) (a)	Rate T2 (1) (b)	Rate T3 (1) (c)
1	Return and Taxes	228	2,317	59
2	Depreciation Expense	164	1,391	52
	Operating Expenses			
3	Distribution	63	487	11
4	General Operating & Engineering	28	285	8
5	Sales	255	53	54
6	Administrative & General	293	658	64
7	Accumulated Deferred Tax Drawdown	(9)	(89)	(3)
8	Total Revenue Requirement (sum of lines 1 to 6)	1,022	5,104	244
9	Monthly Demand Charge Revenue Requirement Adjustment (2)	-	(2,440)	-
10	Revenue Requirement Used to Calculate Monthly Customer Charge (line 7 + line 8)	1,022	2,664	244
11	Billing Units (monthly bills)	528	444	12
12	Monthly Customer Charge ($) (line 9 / line 10 x 1000)	$ 1,936.13	$ 6,000.00	$ 20,371.35

Notes:

(1) Revenue requirement per EB-2011-0210, April 30, 2014, Exhibit G3, Tab 2, Schedule 21, p. 2.

(2) Rate T2 monthly demand charge revenue requirement adjustment recovered through Rate T2 transportation demand charges.

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

Exhibit A, Tab 3, Schedule 1, Dated 2019-11-17

Question:

Please explain why EGI means by "To include high-level information about Phase 1 …" in the description for the Application in the chart shown on page 3 of 4. In particular, is there any other information that would be filed at a later date that is relevant to the Phase 1 application? If so, please identify.

Response

The noted reference refers to the fact that the Application document itself (typically Exhibit A, Tab 2, Schedule 1) sets out the relief requested and only a brief outline of the relevant evidence.

The evidence in support of Phase 1 will be filed at the same time as the Application (around June 30), which is noted in the second line of the table at Exhibit A, Tab 3, Schedule 1, page 3.

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

Exhibit B, Tab 1, Schedule 1, Appendix C, Dated 2019-11-17, page 3

Question:

a) Please explain why EGI believes that is appropriate that the proposed cost allocation changes described in the evidence be approved in this proceeding and then implemented along with all other rate changes in its next rebasing application.

b) Please explain why some cost allocation changes should be approved by the Board in this proceeding, while other proposed cost allocation changes would be brought forward as part of the rebasing application.

c) Is there any reason why the proposed cost allocation changes brought forward in this application cannot be deferred until a complete review of all cost allocation proposals is brought forward as part of the rebasing application?

d) Given that EGI is not recommending changes to rates as part of this proceeding for the reasons set out in paragraph 7, please explain why the Board should approve the proposed changes in this proceeding.

e) Would Board approval of the specific approvals in this proceeding be open to changes as part of the comprehensive cost allocation study to be filed for the rebasing year? If so, why is there a need to approve the proposals in this proceeding? If not, why should the cost allocation for some assets be fixed at the time of rebasing, while other changes would be open to review?

Response

a) Enbridge Gas believes it is appropriate to seek approval of the cost allocation methodology changes related to the Panhandle and St. Clair System, Parkway Station and Dawn Station as part of this proceeding because the proposed changes are responsive to the Board's cost allocation study directive from the MAADs Decision. However, Enbridge Gas does not believe that implementation of these changes is appropriate before rebasing, because rebasing is the forum where the Company will be able to identify and reflect all necessary rate adjustments required to address cost allocation changes across the two legacy utilities, harmonization of rates and rate design considerations as described at Exhibit I.TCPL.1 part d).

b) Enbridge Gas has requested approval of these discrete cost allocation methodology changes in this proceeding to comply with the Board's directive from the MAADs Decision. Enbridge Gas proposes that it is appropriate to wait until rebasing to implement the proposed cost allocation changes changes related to the Panhandle and St. Clair System, Parkway Station and Dawn Station.

c) Assuming that the Board agrees, there is no significant reason why approval of the cost allocation proposals could not be delayed until the 2024 rebasing proceeding.

d) Please see parts a) - c).

e) Please see part c). Should the Board approve the cost allocation methodology proposals related to the Panhandle and St. Clair System, Parkway Station and Dawn Station as part of this proceeding, Enbridge Gas would use the approved methodologies in the preparation of the 2024 cost allocation study. The Board and intervenors could subsequently review and comment on any component of the cost allocation study as part of the 2024 rebasing proceeding. A modest potential benefit to having the proposed cost allocation methodology changes reviewed and determined in this proceeding is that a participant in the rebasing proceeding would presumably have to show reasons why a further change is warranted, given the Board's recent review of the allocation methodologies.

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

Exhibit B, Tab 1, Schedule 1, Appendix C, Dated 2019-11-17, page 24

Question:

Please provide a table at the rate class level that shows the changes in the revenue deficiency/sufficiency for each rate class assuming the changes in the cost allocation methodology as proposed by EGI while maintaining the Board approved revenue-to-cost ratios shown in Table 3.

Response

The Board-approved column (a) of Table 3 at Exhibit B, Tab 1, Schedule 1, Appendix C, p. 24 provides the revenue to cost ratio results of using the Board-approved cost allocation methodologies in the 2019 cost allocation study directive, it is not intended to imply that the ratios are the 2013 Board-approved revenue to cost ratios.

Please see Attachment 1 for changes in the revenue deficiency/sufficiency assuming the level of approved revenue-to-cost ratios from the 2013 cost of service proceeding (EB-2011-0210) were maintained.

The 2013 Board-approved in-franchise revenue to cost ratios represent the difference between the proposed revenue and the allocated revenue requirement by rate class, adjusted by the total S&T margin. The allocation of S&T margin includes adjustments by rate class for rate design considerations.

The revenue to cost ratios provided in the 2019 Cost Allocation Study[1] directive were based on the difference between the current approved revenue (compared to proposed revenue) and the allocated revenue requirement by rate class, including S&T margin without adjustments for rate design considerations. In order to compare the 2013

[1] Exhibit B, Tab 1, Schedule 1, Appendix C, p. 24, Table 3.

revenue to cost ratios to the 2019 cost allocation study results, Enbridge Gas has provided an adjusted revenue to cost ratio that includes the rate change that would be made as part of a cost of service proceeding.

As shown in Attachment 1, column (f), Enbridge Gas would require approximately $22.6 million of S&T margin to maintain the revenue to cost ratios from the 2013 proceeding, which is $12.5 million greater than the 2019 forecasted S&T margin of $9.4 million. Alternatively, Enbridge Gas would need to adjust the rate impacts of the ex-franchise rate classes, such that the revenue to cost ratios of those rate classes exceed 1.0 providing a further contribution toward the S&T margin required by the in-franchise rate classes to maintain 2013 revenue to cost ratios.

ENBRIDGE GAS INC.
Derivation of the Revenue Deficiency / Sufficiency of the Cost Allocation Study Impacts
Assuming 2013 Board-Approved Revenue to Cost Ratios

					2019 Directive Assuming No Rate Design				Adjusted S&T Margin (4)			
Line No.	Particulars ($000's)	2013 Revenue to Cost Ratios (1)	Current Approved Revenue (2)	Revenue Requirement (2)	S&T Margin (2)	Adjusted Revenue to Cost Ratio (3)	Revenue (Deficiency)/ Sufficiency	Rate Impact (%)	Adjusted S&T Margin (4)	Revenue to Cost Ratios	Revenue (Deficiency)/ Sufficiency	Rate Impact (%)
		(a)	(b)	(c)	(d)	(e) = ((c+d)/c))	(f) = (b-c-d)	(g)=(-f/b)	(h) = (a*c-c)	(i)=((c+h)/c)	(j)=(b-c-h)	(k)=(j/b)
	Union North Distribution											
1	Rate 01	0.999	197,961	202,540	(1,583)	0.992	(2,996)	2%	(222)	0.999	(4,357)	2%
2	Rate 10	1.000	27,412	32,587	(448)	0.986	(4,727)	17%	0	1.000	(5,175)	19%
3	Rate 20	0.799	27,521	27,823	(242)	0.991	(60)	0%	(5,601)	0.799	5,299	-19%
4	Rate 25	0.840	2,450	4,085	-	1.000	(1,635)	67%	(652)	0.840	(983)	40%
5	Rate 100	0.999	10,089	11,256	(7)	0.999	(1,160)	11%	(12)	0.999	(1,156)	11%
	Union South Distribution											
6	Rate M1	0.998	455,310	461,900	(2,830)	0.994	(3,760)	1%	(842)	0.998	(5,748)	1%
7	Rate M2	0.972	67,068	71,958	(963)	0.987	(3,927)	6%	(2,005)	0.972	(2,884)	4%
8	Rate M4	0.783	28,675	38,112	(532)	0.986	(8,905)	31%	(8,289)	0.783	(1,148)	4%
9	Rate M5	0.824	2,486	2,641	(2)	0.999	(153)	6%	(464)	0.824	309	-12%
10	Rate M7	0.793	12,450	16,543	(244)	0.985	(3,849)	31%	(3,423)	0.793	(670)	5%
11	Rate M9	0.946	1,158	1,187	(41)	0.966	11	-1%	(64)	0.946	35	-3%
12	Rate M10	0.131	20	18	(0)	0.979	3	-15%	(15)	0.131	18	-89%
13	Rate T1	1.000	11,829	12,853	(199)	0.985	(825)	7%	-	1.000	(1,024)	9%
14	Rate T2	1.000	67,147	60,619	(2,108)	0.965	8,636	-13%	-	1.000	6,528	-10%
15	Rate T3	0.943	6,728	6,237	(230)	0.963	720	-11%	(352)	0.943	843	-13%
16	Total		918,304	950,359	(9,431)		(22,625)		(21,942)		(10,114)	

Notes:

(1) The 2013 revenue to cost ratios for Union North and Union South distribution are based on the total 2013 S&T margin included in rates, adjusted by rate class for rate design considerations. The deficiency/sufficiency excludes gas supply optimization margin recovered in Union North and Union South gas supply commodity rates.

(2) Exhibit B, Tab 1, Appendix C, Working Papers, Schedule 4, p.3. Revenue Requirement excludes S&T margin adjustment.

(3) Adjusted revenue to cost ratios calculated consistent with 2013 Board-approved revenue to cost ratios, which assumes rates are adjusted by the revenue deficiency/sufficiency and any variance to revenue from cost is set equal to the total S&T margin.

(4) Adjusted S&T margin represents the amount of S&T margin required to set rates in 2019 at the same level as 2013 Board-approved revenue to cost ratios. The forecasted 2019 S&T margin is $9.4 million as compared to the calculated margin required to adjust the revenue to cost ratios of $21.9 million.

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

Exhibit B, Tab 1, Schedule 1, Appendix C, Dated 2019-11-17, page 30

Question:

Please provide a copy of the Excel spreadsheet noted as being Exhibit B, Tab 1, Appendix C1.

Response

Exhibit B, Tab 1, Appendix C1 was filed in excel format by Enbridge Gas on February 7, 2020. The cost study in excel format was inadvertently not included in the original evidence submission dated November 27, 2019.

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

Exhibit B, Tab 1, Appendix C, Working Papers, Schedule 2, Dated 2019-11-17, page 1

Question:

The revenue requirement by function shows the non-station and non-Dawn-Parkway transmission functions as being Panhandle, St. Clair and Other Transmission. The rate base figure for Other Transmission ($451.778 million) is larger than the rate base for St. Clair ($3.209 million) and Panhandle ($332.332 million) combined.

a) Please explain why the St. Clair transmission allocator is still needed, given that it is a fraction of the size of either the Panhandle or Other Transmission functions?

b) In particular, why could the St. Clair function be combined with the Other Transmission function?

c) Please provide a table that breaks out the transmission assets included in the Other Transmission function, along with an estimated value of the 2019 rate base associated with each of the individual components.

Response

a) Enbridge Gas included the St. Clair function in the cost allocation study because the use of the St. Clair System is different than the Panhandle System and Other Transmission. The St. Clair System provides ex-franchise Rate C1 transportation service between Dawn and St. Clair and Bluewater, as compared to the Panhandle System that provides both Rate C1 and Union South in-franchise transportation and Other Transmission that provides Union South in-franchise transportation only.

b) If Enbridge Gas were to include the costs of the St. Clair System in the current Other Transmission function, the costs of the St. Clair System would be allocated to all Union South in-franchise customers in proportion to firm design day demands rather than to Rate C1. Alternatively, Enbridge Gas could direct assign the costs of the St. Clair System to Rate C1 within the Panhandle or Other Transmission function, however, the Company included the separate function for purposes of the cost study directive to provide transparency to the split of the Ojibway / St. Clair function within the existing cost study.

c)

Table 1

Components of Other Transmission Demand Rate Base

Line No.	Particulars ($000's)	Gross Plant In Service (1)	Accumulated Depreciation (1)	Rate Base
		(a)	(b)	(c) = (b-a)
	Transmission			
1	Land	5,549	-	5,549
2	Land Rights	24,315	4,725	19,590
3	Mains	423,276	118,769	304,507
4	Compressor Equipment (2)	1	437	(436)
5	Measuring and Regulating	162,965	58,786	104,179
6	Structures & Improvements	8,332	3,283	5,049
7	Other	706	-	706
8	General Plant	17,446	7,908	9,539
9	Working Capital	3,096	-	3,096
10	Total	645,685	193,907	451,778

Notes:
(1) Exhibit B, Tab 1, Appendix C1, Schedule 2.17.
(2) Enbridge Gas notes the misallocation of compressor equipment gross plant and accumulated depreciation to the Other Transmission Demand functional classification. The impact on Other Transmission Demand revenue requirement is immaterial.

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

Report on Unaccounted For Gas, Dated December, 2019

Question:

Did ScottMadden attempt to calculate the UFG percentages for the legacy Union North and legacy Union South rate zones rather than the legacy Union? If not, why not? If yes, please provide the UFG percentages for Union North and Union South for the same 10 year period used for the Union legacy figure of 0.31 percent.

Response

ScottMadden relied on the UFG percentages submitted previously to the Ontario Energy Board by legacy Union Gas which included the UFG identified for both the southern and northern operating areas. ScottMadden's primary focus was to: (a) compare legacy Union Gas' and legacy Enbridge Gas Distribution's UFG levels to those in the industry; (b) compare the sources of UFG to those in the industry; and (c) compare the practices used to monitor and manage UFG to those in the industry. ScottMadden was able to complete those tasks utilizing the UFG percentages submitted previously to the OEB by legacy Union Gas.

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

Exhibit B, Tab 2, Schedule 1, Dated 2020-01-15, page 30 & Exhibit B, Tab 2, Schedule 1, Dated 2019-10-25, page 30

Question:

In the original filing (2019-10-25), the Windsor Line Replacement assets were proposed to be categorized as Other Transmission assets, while in the updated filing (2020-01-15), the assets are proposed to be categorized as Union South Distribution Demand.

a) Please explain the change in the proposed categorization and allocation of the associated revenue requirement of the Windsor Line Replacement.

b) How did EGI categorize/allocate the assets associated with the existing Windsor Line?

c) What is the estimated net book value of the existing Windsor Line assets that will be replaced by the new Windsor Line, including abandoned stations and any service connections, meters, regulators, etc., that will be replaced?

d) Please explain the difference in the updated proposed allocation of the Windsor Line Replacement Project with the use of the Other Transmission allocator approved by the Board for the Burlington Oakville Pipeline Project (EB-2014-0182).

Response

a) Enbridge Gas expects to categorize the Windsor Line Replacement project assets as distribution in the plant accounting records. The ICM cost allocation was changed to match the plant accounting record categorization. Transmission is defined in the TSSA Oil and Gas Pipeline Systems Code Adoption document as any pipeline operating at or above 30% SMYS, and the Windsor Line Replacement project assets will operate at less than 30% SMYS.

b) The existing Windsor Line is categorized in the plant accounting records as transmission and allocated in proportion to Union South in-franchise firm design day demands.

c) The existing Windsor Line has a NBV of $1,091,559 as of December 31, 2019.

d) In EB-2014-0182 Union proposed, and the Board approved, the Burlington-Oakville pipeline as transmission and allocated in proportion to Union South in-franchise firm design day demands. As described in part a), the proposed Windsor Line Replacement assets will be categorized as distribution in the Company's plant accounting records. Accordingly, the costs have been allocated using the Distribution demand allocator in proportion to Union South in-franchise design day demands of firm and interruptible customers excluding customers served directly off transmission lines. Please see Exhibit I.LPMA.11.

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

Exhibit B, Tab 2, Schedule 1, Dated 2020-01-15

Question:

a) Please update Tables 1 and 2 to reflect actual data for 2019. If actual data for 2019 is not yet available, please update the tables to reflect the most recent year-to-date actuals in 2019 along with the estimate of the remainder of the year.

b) Tables 1 and 2 are titled capital expenditures. Are these total capital expenditures or in-service capital expenditures?

Response

a) Please refer to the tables below for the updated 2019 actual data:

Table 1

Capital Expenditures by category (2014-2023) – EGD Rate Zone ($ millions)

Line No.	**Category**	**2014 Actual**	**2015 Actual**	**2016 Actual**	**2017 Actual**	**2018 Actual**
		(a)	(b)	(c)	(d)	(e)
1	General Plant	69.0	91.9	82.6	48.1	47.3
2	System Access[5]	112.8	105.2	118.3	109.3	108.9
3	System Renewal	96.5	102.7	109.1	102.2	92.3
4	System Service	190.5	569.6	127.1	20.2	22.9
5	Total Overhead	141.3	145.9	156.4	148.1	140.2
6	**Total - EGD Rate Zone**	**610.1**	**1,015.3**	**593.5**	**427.8**	**411.6**
7	**In-Service Additions**	**507.7**	**364.0**	**1411.2**	**448.4**	**387.3**

Line No.	**Category**	**2019 Actual**	**2020 Budget**	**2021 Budget**	**2022 Budget**	**2023 Budget**
		(f)	(g)	(h)	(i)	(j)
1	General Plant	70.4	46.8	67.2	51.1	31.6
2	System Access[1]	151.1	131.4	127.8	127.4	127.5
3	System Renewal	110.4	168.8	188.9	355.2	171.8
4	System Service	23.9	13.4	11.3	23.4	14.1
5	Total Overhead	151.6	156.8	140.8	143.9	148.4
6	**Total - EGD Rate Zone**	**507.4**	**517.2**	**536.0**	**701.1**	**493.4**

[1] System access capital does not include Community Expansion and Compressed Natural Gas.

Table 2

Capital Expenditures by category (2014-2023) – Union Rate Zones ($ millions)

Line No.	Category	2014 Actual	2015 Actual	2016 Actual	2017 Actual	2018 Actual
		(a)	(b)	(c)	(d)	(e)
1	General Plant	56.5	51.4	44.8	42.8	48.0
2	System Access[6]	83.9	107.8	105.6	96.2	83.5
3	System Renewal	83.8	73.0	76.3	87.6	102.5
4	System Service	190.4	391.5	734.3	412.2	198.1
5	Total Overhead	68.2	71.5	77.2	78.6	81.0
6	**Total - Union Rate Zones**	**482.9**	**695.2**	**1,038.2**	**717.5**	**513.1**
7	**In-Service Additions**	**380.9**	**652.9**	**857.1**	**1,035.2**	**471.3**

Line No.	Category	**2019 Actual**	**2020 Budget**	**2021 Budget**	**2022 Budget**	**2023 Budget**
		(f)	(g)	(h)	(i)	(j)
1	General Plant	51.8	52.0	65.8	61.4	63.5
2	System Access[2]	104.4	86.9	93.7	91.0	97.3
3	System Renewal	120.1	206.9	237.2	135.0	210.6
4	System Service	148.4	106.1	269.6	126.1	178.5
5	Total Overhead	83.1	76.4	80.0	80.0	80.0
6	**Total - Union Rate Zones**	**507.8**	**528.3**	**746.3**	**493.5**	**629.9**

b) The historical years of 2014-2018 represent capital expenditures and the 2019 actual and 2020-2023 budget years represent an in-service view. The EGD and Union rate zones were not reporting actual in-service capital additions in the categories listed above prior to 2019. For comparison purposes, in-service capital additions are presented in line 7 of the tables. Note for the EGD rate zone, the primary drivers for the variance between capital expenditure and in-service additions are the WAMS and GTA projects. For the UG rate zone, the primary drivers are the capital pass-through projects (Dawn-Parkway and Panhandle).

[2]System access capital does not include Community Expansion and Compressed Natural Gas.

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

Exhibit B, Tab 2, Schedule 1, Dated 2020-01-15, page 23

Question:

Please confirm that the $14.9 million shown as in-service capital spending in 2021 for the Windsor Line Replacement Project has not been included in the proposed ACM or the associated rate riders to be put in place in 2020.

Response

Confirmed.

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

Exhibit B, Tab 2, Schedule 1, Appendix A, Dated 2019-10-25

Question:

a) Please update Tables A through H to reflect actual data for 2019. If actual data for 2019 is not yet available, please update the tables to reflect the most recent year-to-date actuals in 2019 along with the estimate of the remainder of the year.

b) Please show where the $91.9 million in in-service capital spending in 2020 associated with the Windsor Line Replacement Project is shown in Tables B, D, F and/or H.

c) Please reconcile the $91.9 million figure shown on page 23, with the $84.248 million shown on page 2 of Appendix E of Exhibit B, Tab 2, Schedule 1.

Response

a) Please see the updated tables below:

Table A

General Plant Capital Expenditures by category (2014-2023) – EGD Rate Zone ($ Millions)

Line No.	**Category**	**2014 Actual**	**2015 Actual**	**2016 Actual**	**2017 Actual**	**2018 Actual**	**2019 Actual**	**2020 Budget**	**2021 Budget**	**2022 Budget**	**2023 Budget**
1	Equipment & Materials	0.4	1.3	-	2.4	2.1	0.1	0.5	0.5	0.5	0.5
2	Furniture/Structures & Improvements	9.4	30.3	22.1	9.4	8.7	33.6	23.1	38.9	19.6	2.5
3	IT Implementation	20.0	20.8	18.6	27.7	32.7	22.3	15.1	21.5	24.9	22.3
4	Land - Storage	1.3	-	-	-	-	-	-	-	-	-
5	Leasehold Improvements	0.8	-	-	-	-	-	-	-	-	-
6	Structures and Improvement - Storage	0.3	0.5	3.9	-	0.2	-	-	-	-	-
7	Tools	11.6	3.3	0.7	-	1.3	7.3	0.8	0.8	1.0	1.0
8	Vehicles	5.8	8.1	1.7	6.6	2.3	7.1	7.3	5.5	5.1	5.3
9	WAMS	19.3	27.5	35.7	2.0	-	-	-	-	-	-
10	**General Plant - EGD Rate Zone**	**69.0**	**91.9**	**82.6**	**48.1**	**47.3**	**70.4**	**46.8**	**67.2**	**51.1**	**31.6**

Table B

General Plant Capital Expenditures by category (2014-2023) – Union Rate Zones ($ Millions)

Line No.	Category	2014 Actual	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 Actual	2020 Budget	2021 Budget	2022 Budget	2023 Budget
1	Tools	3.5	2.7	2.4	2.7	2.0	1.5	1.9	1.6	1.6	1.7
2	LNG Capital Maintenance	-	-	0.1	0.2	-	-	-	-	-	-
3	Measurement Electronics Upgrades	-	-	-	0.1	0.8	-	0.1	0.1	0.1	0.1
4	Compressor and Dehy Capital Maintenance	0.1	-	-	-	1.4	-	-	-	-	-
5	Fleet	9.1	4.2	3.1	6.2	7.7	12.4	7.0	12.0	8.0	8.0
6	Land Rights	0.4	0.3	0.2	0.3	-	-	0.1			
7	Service Facilities	14.5	14.9	8.7	9.1	12.3	7.7	11.6	15.0	15.0	15.0
8	Other - Indirect Materials	0.5	(0.8)	0.2	0.3	-	0.2	0.4	-	-	-
9	Service Facilities - Dawn	-	4.1	6.1	1.5	-	-	-	-	-	-
10	IT Implementation	28.5	26.0	23.9	22.4	23.8	30.0	30.9	37.1	36.7	38.7
11	**General Plant - Union Rate Zones**	**56.5**	**51.4**	**44.8**	**42.8**	**48.0**	**51.8**	**52.0**	**65.8**	**61.4**	**63.5**

Table C

System Access Capital Expenditures by category (2014-2023) – EGD Rate Zone ($ Millions)

Line No.	**Category**	**2014 Actual**	**2015 Actual**	**2016 Actual**	**2017 Actual**	**2018 Actual**	**2019 Actual**	**2020 Budget**	**2021 Budget**	**2022 Budget**	**2023 Budget**
1	Commercial	19.5	20.3	26.0	19.5	19.8	25.5	20.7	21.1	20.9	20.9
2	Industrial	0.2	(0.1)	3.7	3.9	(1.9)	0.3	3.9	4.0	3.9	3.9
3	Meters - Capital Purchase Program (Growth)	5.7	7.5	3.4	6.7	5.1	12.1	4.4	6.4	7.1	7.5
4	NGV	0.7	1.5	6.4	2.1	7.2	1.3	3.0	1.0	1.0	0.9
5	Rebillable Relocations	2.7	1.2	9.8	3.5	(2.7)	46.1	3.0	7.7	7.7	7.7
6	Residential	85.6	71.6	66.2	70.8	81.4	65.6	96.4	87.6	86.8	86.6
7	Sales Stations - New	(1.5)	3.2	2.8	2.8	-	0.2	-	-	-	-
8	**System Access - EGD Rate Zone**	**112.8**	**105.2**	**118.3**	**109.3**	**108.9**	**151.1**	**131.4**	**127.8**	**127.4**	**127.5**

Table D

System Access Capital Expenditures by category (2014-2023) – Union Rate Zones ($ Millions)

Line No.	**Category**	**2014 Actual**	**2015 Actual**	**2016 Actual**	**2017 Actual**	**2018 Actual**	**2019 Actual**	**2020 Budget**	**2021 Budget**	**2022 Budget**	**2023 Budget**
1	CNG	-	-	-	-	-	-	-	-	-	-
2	General Customer Growth	64.3	75.7	85.4	70.0	66.7	85.2	63.8	69.7	67.0	73.3
3	Municipal Replacement	19.6	32.1	20.2	26.2	16.8	19.2	23.1	24.0	24.0	24.0
4	**System Access - Union Rate Zones**	**83.9**	**107.8**	**105.6**	**96.2**	**83.5**	**104.4**	**86.9**	**93.7**	**91.0**	**97.3**

Table E

System Renewal Capital Expenditures by category (2014-2023) – EGD Rate Zone ($ Millions)

Line No.	Category	2014 Actual	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 Actual	2020 Budget	2021 Budget	2022 Budget	2023 Budget
1	Compressor Equipment - Storage	4.5	4.7	5.6	9.7	6.9	0.2	11.7	57.4	11.2	12.0
2	Corrosion Prevention	0.5	1.3	0.5	1.3	1.9	3.2	1.2	1.3	1.3	1.3
3	Field Lines - Storage	0.1	0.7	1.5	0.5	0.3	-	1.7	0.6	1.0	3.5
4	Gate & Feeder Stations	7.4	10.8	7.6	5.2	6.2	1.4	11.8	7.3	13.1	10.2
5	Inside Regulator Program	0.1	6.4	6.6	3.1	0.8	0.1	0.5	0.5	0.5	0.5
6	Integrity Digs	9.1	3.9	2.2	1.9	(0.6)	1.2	4.1	-	-	-
7	Integrity Retrofit	0.4	0.1	5.1	0.9	1.1	0.4	8.6	-	-	-
8	Main Replacement	26.5	12.8	18.9	16.1	19.9	13.0	58.7	29.7	244.2	53.4
9	Measurement and Regulating Equipment - Storage	0.5	-	-	-	-	-	-	-	0.7	0.2
10	Meters - Capital Purchase Program (Maintenance)	13.3	17.4	7.9	15.7	11.8	28.2	10.2	15.0	16.6	17.5
11	Non-Rebillable Relocations	-	-	-	-	1.3	2.5	2.0	2.0	2.0	2.0
12	Regulator Refit	15.2	17.9	17.5	12.3	14.0	29.2	16.9	17.9	18.3	18.6
13	Remediation - Customer Assets	-	-	-	1.0	1.0	2.0	2.9	1.0	0.7	0.7
14	Service Relay	10.9	12.8	20.7	21.6	19.7	22.4	24.8	28.0	31.5	34.0
15	Station Rebuilds	4.8	8.1	11.9	9.9	6.5	5.9	9.5	24.9	12.0	12.7
16	Wells and Well Equipment - Storage	3.3	5.8	3.1	3.0	1.5	0.7	4.2	3.3	2.1	5.2
17	**System Renewal - EGD Rate Zone**	**96.5**	**102.7**	**109.1**	**102.2**	**92.3**	**110.4**	**168.8**	**188.9**	**355.2**	**171.8**

Table F

System Renewal Capital Expenditures by category (2014-2023) – Union Rate Zones ($ Millions)

Line No.	**Category**	**2014 Actual**	**2015 Actual**	**2016 Actual**	**2017 Actual**	**2018 Actual**	**2019 Actual**	**2020 Budget**	**2021 Budget**	**2022 Budget**	**2023 Budget**
1	Bare and Unprotected steel	-	-	-	-	-	3.7	13.6	10.7	12.9	9.1
2	Cathodic Protection	5.3	5.5	6.2	7.2	5.9	7.0	8.0	10.0	10.0	6.7
3	Compression Equipment	2.9	3.2	0.9	0.9	0.1	1.0	0.9	1.2	20.0	104.2
4	Compressor Overhauls	2.2	0.4	4.7	0.6	-	-	-	-	0.4	8.9
5	Excess Flow Valves	-	-	-	0.2	-	-	-	-	-	-
6	General Mains	3.5	2.3	3.9	4.9	25.5	10.0	2.4	3.4	3.4	3.4
7	Integrity Management Program	12.4	12.3	11.7	20.0	22.7	37.4	34.4	13.8	12.9	12.4
8	Leakage	0.1	-	-	-	-	2.9	2.7	4.3	4.3	4.3
9	LNG Capital Maintenance	2.1	0.2	1.0	1.9	0.1	-	0.2	-	6.2	-
10	Measurement Electronics Upgrades	1.4	1.5	1.6	2.0	0.3	0.9	4.3	3.3	2.7	2.2
11	Measurement Upgrade	6.2	0.3	-	-	-	-	-	-	-	-
12	Meter Exchange Program	25.8	29.2	30.8	29.4	32.7	43.4	33.5	30.5	30.8	31.8
13	Replacement of Vaulted Stations	0.1	-	-	-	-	-	1.4	3.5	1.6	1.5
14	Service Replacement	2.8	4.0	4.7	4.6	5.0	3.2	5.2	4.5	4.6	4.7
15	Station Painting	0.3	0.4	-	0.2	1.8	2.1	2.7	2.7	2.7	2.7
16	Stations Capital Maintenance	11.1	7.5	4.5	10.9	8.4	6.3	10.0	16.6	12.6	13.1
							-				

17	Storage Integrity	0.5	1.1	1.1	0.8	-		0.9	-	-	-
18	Vintage Pipeline Replacement	-	-	-	-	-	-	80.2	124.0	3.0	-
19	General Pipeline Maintenance	7.1	5.1	5.2	3.8	-	2.2	6.5	8.7	6.9	5.6
20	General Pipeline Maintenance – Dawn	-	-	-	0.1	-	-	-	-	-	-
21	**System Renewal - Union Rate Zones**	**83.8**	**73.0**	**76.3**	**87.6**	**102.5**	**120.1**	**206.9**	**237.2**	**135.0**	**210.6**

<u>Table G</u>

System Service Capital Expenditures by category (2014-2023) – EGD Rate Zone ($ Millions)

Line No.	**Category**	**2014 Actual**	**2015 Actual**	**2016 Actual**	**2017 Actual**	**2018 Actual**	**2019 Actual**	**2020 Budget**	**2021 Budget**	**2022 Budget**	**2023 Budget**
1	Carbon Capture	-	-	-	-	-	-	-	-	-	-
2	Integrity Initiatives	3.2	8.8	1.8	4.7	6.7	7.1	3.3	3.4	3.7	2.4
3	MOP	0.9	1.0	0.8	1.4	1.4	0.2	-	-	-	-
4	Records Integrity	3.1	1.9	1.8	4.6	4.9	9.5	0.1	0.1	0.1	0.1
5	System Reinforcement	10.8	6.8	7.9	4.7	9.9	7.1	10.0	7.8	19.6	11.6
6	GTA	172.4	551.1	114.8	4.8	-	-	-	-	-	-
7	**System Service - EGD Rate Zone**	**190.5**	**569.6**	**127.1**	**20.2**	**22.9**	**23.9**	**13.4**	**11.3**	**23.4**	**14.1**

Table H

System Service Capital Expenditures by category (2014-2023) – Union Rate Zones ($ Millions)

Line No.	Category	2014 Actual	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 Actual	2020 Budget	2021 Budget	2022 Budget	2023 Budget
1	Excess Flow Valves	4.3	3.8	1.3	0.7	-	-	-	-	-	-
2	General Mains	0.1	0.1	0.1	-	-	-	-	-	-	-
3	LNG Capital Maintenance	0.1	-	-	0.1	-	-	-	-	-	-
4	Measurement Electronics Upgrades	-	-	-	-	-	0.1	0.1	-	-	-
5	Measurement Upgrade	0.1	-	0.1	-	-	-	-	-	-	-
6	Storage Integrity	-	0.6	1.7	2.5	-	0.3	0.4	0.3	0.3	0.3
7	Class Location	16.5	14.4	26.7	27.2	19.7	23.7	20.8	20.0	15.0	15.0
8	Compressor and Dehy Capital Maintenance	0.1	-	-	-	-	-	0.8	0.4	-	-
9	Depth of Cover <30% SMYS	-	0.1	-	-	-	-	0.7	0.1	0.5	-
10	Depth of Cover >30% SMYS	-	-	-	-	-	-	-	-	-	-
11	Distribution Reinforcement	5.6	5.9	16.1	9.3	94.5	18.2	5.9	7.2	36.6	21.4
12	Emissions Action Plan	-	0.6	2.3	4.1	-	0.1	-	0.2	0.1	0.1
13	In Franchise Growth	0.5	(0.1)	-	-	-	-	-	-	-	-
14	MOP Verification	-	-	-	-	-	-	-	-	-	5.0
15	Odourant Upgrades	1.1	0.8	0.8	0.7	0.6	1.0	1.4	1.0	1.0	1.0
16	Station Reinforcement	3.1	1.0	0.7	-	0.1	0.7	-	3.8	1.4	54.8

17	Storage Improvements	-	-	0.6	1.1	2.0	0.6	2.5	1.2	1.2	1.3
18	System Growth	157.5	364.0	683.5	366.4	43.1	81.5	13.5	206.9	69.9	69.2
19	Transmission Reinforcement	0.8	0.1	0.4	-	38.1	22.2	59.3	28.4	-	10.3
20	General Safety	0.4	0.1	-	-	-	-	0.7	0.1	0.1	0.1
21	Integrated Resource Planning	-	-	-	0.1	-	-	-	-	-	-
22	**System Service - Union Rate Zones**	**190.4**	**391.5**	**734.3**	**412.2**	**198.1**	**148.4**	**106.1**	**269.6**	**126.1**	**178.5**

b) The in-service capital for the Windsor Line Replacement project is shown in Table F line 18, Vintage Pipeline Replacement:

Table F, Line No. 18 Project Detail			**2020 Budget**	**2021 Budget**	**2022 Budget**	**2023 Budget**
System Renewal	Vintage Pipeline Replacement	Windsor Line Replacement	80.2	12.5	-	-

Note that the table represents direct capital in-service spend, associated overheads are shown in Exhibit B, Tab 2, Schedule 1, Table 2, p5.

c) The reconciliation is shown in Exhibit B, Tab 2, Schedule 1, Table 7, p.15. The total in-service capital for the Windsor Line Replacement Project exceeds the maximum eligible incremental capital for the Union rate zones. The figure of $84.248 Million is the maximum amount Union is able to recover under the ICM funding mechanism.

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

Exhibit B, Tab 2, Schedule 1, Appendix F, page 2, Dated 2020-01-15 & 2019-10-25

Question:

Please explain why some of the figures shown in column (a) are the same between the two schedules while others are different, despite different allocators being used. For example, why are the Rate M1 and Rate M2 figures the same under both allocators, while the Rate M4 (F) figures are different?

Response

The original allocation of the Windsor Line Replacement Project costs dated 2019-10-25 was prepared using the Other Transmission Demand allocator which allocates costs in proportion to the 2020 forecast Union South in-franchise firm design day demands.

The updated allocation of the Windsor Line Replacement Project costs dated 2020-01-15 was prepared using the Distribution Demand allocator which allocates costs in proportion to the 2020 forecast Union South in-franchise design day demands of both firm and interruptible customers served by the distribution system excluding the design day demands of customers served directly off transmission lines.

Please see Attachment 1 for the factors contributing to the difference between the Other Transmission Demand and Distribution Demand allocators.

UNION RATE ZONES
Comparison of ICM Allocators

Line No.	Particulars ($10^3m^3/d$)	Other Transmission Demand Allocator (1)	Forecast Interruptible Design Day Demands	Design Day Demands Served Off Transmission	Distribution Demand Allocator (2)
		(a)	(b)	(c)	(d) = (a+b-c)
1	Rate M1	31,030	-	-	31,030
2	Rate M2	11,714	-	-	11,714
3	Rate M4 (F)	5,248	-	189	5,059
4	Rate M4 (I)	-	87	-	87
5	Rate M5 (F)	55	-	-	55
6	Rate M5 (I)	-	291	-	291
7	Rate M7 (F)	2,926	-	622	2,304
8	Rate M7 (I)	-	589	111	478
9	Rate M9	538	-	538	-
10	Rate M10	4	-	4	-
11	Rate T1 (F)	2,248	-	156	2,092
12	Rate T1 (I)	-	-	-	-
13	Rate T2 (F)	23,712	-	19,604	4,108
14	Rate T2 (I)	-	5,216	3,844	1,372
15	Rate T3	2,527	-	2,527	-
16	Total Union South	80,002	6,183	27,595	58,590

Notes:
(1) Exhibit B, Tab 2, Schedule 1, Appendix F, p. 2 (Dated 2019-10-25).
(2) Exhibit B, Tab 2, Schedule 1, Appendix F, p. 2 (Updated 2020-01-15).

ENBRIDGE GAS INC.

Answer to Interrogatory from
Ontario Greenhouse Vegetable Growers ("OGVG")

Interrogatory

Reference:

General

Preamble:

The Cost Allocation Study does not appear to provide information about the customers in each class affected by the proposed updated allocations.

Question:

a) Please provide the number of customers in each of the Union Franchise Area rate classes consistent with the 2019 rate year used in the submitted Cost Allocation Study; please also provide the number of customers in each of the Union Franchise Area rate classes identified by Enbridge Gas as "greenhouses".

Rate Class	Total Customers	Greenhouse Customers

Response

Please see Table 1.

Table 1
Total Number of Customers and Greenhouse Customers by Rate Class

Line No.	Rate Class	Total Customers	Greenhouse Customers
		(a)	(b)
	Union North		
1	Rate 01	355,421	14
2	Rate 10	1,952	3
3	Rate 20	49	-
4	Rate 100	11	-
5	Rate 25	47	-
	Union South		
6	Rate M1	1,139,866	310
7	Rate M2	7,548	246
8	Rate M4	194	90
9	Rate M5	48	13
10	Rate M7	30	11
11	Rate M9	2	-
12	Rate M10	1	-
13	Rate T1	38	6
14	Rate T2	23	-
15	Rate T3	1	-
16	Total	1,505,229	693

ENBRIDGE GAS INC.

Answer to Interrogatory from
Ontario Greenhouse Vegetable Growers (“OGVG”)

Interrogatory

Reference:

Exhibit B Tab 1 Appendix C Schedule 2 page 1 Column (a)

Preamble:

There does not appear to be any text that explains the counterintuitive result (on its face) in the Cost Allocation Study that a particular category of costs would have a negative value.

Question:

a) Please explain why the rate base figure under Purchase Production is negative.

Response

The Purchase Production rate base amount of $(9.992) million includes ABC Receivables/Payables working capital of $(15.925) million offset by general plant and other working capital of $5.933 million.

The ABC Receivable/Payable working capital amount represents the cash flow impact to Enbridge Gas related to the timing difference between collection of amounts from ABC customers by the Company and remittance of amounts to brokers on behalf of ABC customers. The negative rate base amount reflects a positive cash flow impact to Enbridge Gas which reduces rate base.

ENBRIDGE GAS INC.

Answer to Interrogatory from Ontario Greenhouse Vegetable Growers ("OGVG")

Interrogatory

Reference:

Exhibit B Tab 1 Schedule 1 Appendix C page 3

Preamble:

The cost allocation study results, on their own, do not represent the final rate adjustment that may occur as part of a cost of service proceeding. The final rate adjustment of a cost of service proceeding would include rate design and other adjustments that may be required to manage revenue to cost ratios, maintain rate class continuity and address bill impacts.

Question:

a) Please confirm that Enbridge Gas' current rates (for the Union Franchise area) are the result of the final rate adjustment performed in the context of the EB-2011-0210 proceeding (as adjusted over time through the application of incentive regulation), the most recent full cost of service proceeding in relation to the Union Gas Franchise area, with the results of that final rate adjustment being summarized in the Draft Rate Order filed by Union Gas on December 13, 2012, Working Papers, Schedules 13 and 14.

Response

Confirmed.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Ontario Greenhouse Vegetable Growers ("OGVG")

Interrogatory

Reference:

Exhibit B Tab 1 Schedule 1 Appendix C page 6.

Preamble:

Enbridge Gas has prepared the cost allocation study based on a 2019 test year. Enbridge Gas has based the revenue requirement on the 2019 forecast costs of the Union rate zones, which have been set to equal the forecast of 2019 revenue.

Question:

a) Please explain what Enbridge Gas means when it says that the forecast costs of the Union rate zones have been set to equal the forecast of 2019 revenue; please explain to what extent the revenue requirement is based on the actual forecast of costs for 2019, and to what extent the revenue requirement has been, presumably, adjusted so as to be "set to equal the forecast of 2019 revenue".

Response

Enbridge Gas's 2019 forecast for the Union rate zones was prepared prior to the amalgamation of Union Gas Limited and Enbridge Gas Distribution and prior to the MAADs Decision.

To prepare the 2019 cost allocation study in a manner which responds to the Board's concerns regarding the cost allocation issues raised by parties from the MAADs proceeding, Enbridge Gas set the 2019 forecast revenue requirement used in the cost allocation study to equal the forecast of 2019 revenue for the Union rate zones. Preparing the cost allocation study using a revenue requirement that is equal to the forecast of revenue under the rate setting mechanism allows for the cost allocation study results to demonstrate the impact of shift of allocated costs by rate class without the impact of a sufficiency or deficiency.

To set the 2019 revenue requirement equal to the forecast of revenue, Enbridge Gas reduced the operating expense forecast for the Union rate zones to reflect an expectation of reduced operating expenses as a result of the amalgamation. No adjustment was made to other components of the forecast revenue requirement for 2019. By applying this adjustment, the revenue requirement more closely aligns the cost allocation study with the forecast of costs of the Union rate zone as part of the integrated utility.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Ontario Greenhouse Vegetable Growers ("OGVG")

Interrogatory

Reference:

Exhibit B Tab 1 Schedule 1 Appendix C page 10.

Preamble:

Both the Panhandle System and St. Clair System provide ex-franchise Rate C1 transportation between Dawn and Ojibway, St. Clair and Bluewater.

Question:

a) Please confirm whether the Panhandle System provides ex-franchise Rate C1 transportation between Dawn and Ojibway and between St. Clair and Bluewater, or whether the Panhandle System only provides ex-franchise Rate C1 transportation between Dawn and Ojibway. Similarly, please confirm whether the St. Clair System provides ex-franchise Rate C1 transportation between Dawn and Ojibway and between St. Clair and Bluewater, or whether the St. Clair System only provides ex-franchise Rate C1 transportation between St. Clair and Bluewater.

Response

The Panhandle System provides ex-franchise Rate C1 transportation between Dawn and Ojibway only. The St. Clair System provides ex-franchise Rate C1 transportation between Dawn and St. Clair and Bluewater.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Pollution Probe

Interrogatory

Reference:

Enbridge Asset Management Plan 2019-2028, Section 1.8.9

"EGD's Community Expansion Strategy is to continue assessing and pursuing opportunities to provide gas distribution service to under-served communities. The process will require submitting applications to the Ontario Ministry of Infrastructure for approval to proceed as well as the subsequent submissions of Leave to Construct (LTC) applications to the OEB"

Question:

a) Please provide details on any additional approval requests Enbridge will make to the OEB in 2020 related to community expansion (e.g. leave to construct)?

b) For each project, please indicate if the request is incremental to the projects outlined in the above note Asset Management Plan.

Response

a) The following community expansion projects were approved by Ontario Ministry of Infrastructure under Bill 32 Phase 1, Ontario Regulation 24/19 under Ontario Energy Board Act,1998 and have not yet been subject to review by the Board:

Cornwall Island Project	EGD Rate Zone
Hiawatha First Nation Project	EGD Rate Zone
Northshore and Peninsula Roads Project	Union North Rate Zone

Enbridge Gas filed its application for Leave to Construct (LTC) for the Northshore and Peninsula Roads Project in January, 2020 and will apply for any required approvals for the remaining projects in due course.

Subsequent submissions of applications to the Board might be possible in 2020 in addition to the above listed projects based on the outcome of the Bill 32 Phase 2 decision by the Ontario Ministry of Infrastructure in 2020.

b) These requests as identified in part a) are not incremental to the projects outlined in the above noted Asset Management Plan.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Pollution Probe

Interrogatory

Reference:

[Exhibit B,Tab 2]

Question:

a) Enbridge is presently requesting Board approval for a $203.5 million transmission pipeline project through EB-2019-0159 and intends for rate recovery through the ICM mechanism. Please provide project details and explain how this $203.5 million amount is factored into the incremental capital module details included in this proceeding.

b) If the OEB does not approve Enbridge's request in EB-2019-0159, how will this impact the ICM?

c) Please explain how Enbridge determines what projects to include as incremental projects and why a business case for the above noted project was not included in the filing.

d) Please provide the status of all projects proposed to be funded under the ICM that require additional OEB approvals.

Response

a) to c) Enbridge Gas is not seeking any relief for the project specified in this question in this proceeding.

d) Enbridge Gas is seeking ICM funding for the Don River Replacement Project and the Windsor Line Replacement Project in this proceeding. The Don River Replacement leave to construct application was approved by the Board in EB-2018-0108. The Windsor Line Replacement project Leave to Construct application is currently a live proceeding in front of the Board under docket number EB-2019-0172.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Pollution Probe

Interrogatory

Reference:

In EB-2019-0159 Enbridge Gas brought forward an IRP Proposal[1]

Question:

a) Please explain what integrated resource planning (IRP) considerations Enbridge included in development of its Utility System Plan and/or Asset Management Plan.

b) If Enbridge did not include IRP considerations in development of its Utility System Plan and/or Asset Management Plan, please explain why these issues were not considered.

Response

a) IRP has not been included in the legacy Asset Management Plans or the Utility System Plan. Load Forecasting includes impacts of broad-based DSM programs but has yet to factor in geotargeted Integrated Resource Planning Alternatives ("IRPAs") and related forecasting as adequate policy direction is pending the separate IRP Proposal proceeding that is anticipated to address issues of broader applicability. As part of EB-2019-0159 Procedural Order No. 1 issued on January 30, 2020 the Board indicated that "…the IRP Proposal raises issues of broad applicability that are best dealt with outside of the context of a project-specific Leave to Construct proceeding. The OEB expects to provide further direction on the next steps regarding consideration of Enbridge Gas's IRP Proposal in the near future. The OEB has determined that Enbridge Gas's IRP Proposal should be heard separate and apart from the current Leave to Construct application proceeding."[1]

[1] EB-2019-0159 Procedural Order No. 1, Page 2

[1] EB-2019-0159 Exhibit A Tab 13

b) Consistent with EGI's IRP Proposal in EB-2019-0159, Enbridge Gas notes that receiving adequate policy direction is a necessary step towards understanding what IRP consideration should be built into future AMPs as well as into future reinforcement pipeline applications.

[1] EB-2019-0159 Exhibit A Tab 13

ENBRIDGE GAS INC.

Answer to Interrogatory from
Pollution Probe

Interrogatory

Reference:

[Exhibit B,Tab 3, Sch. 1]

Question:

a) Prior to implementing the e-billing changes in 2019, did Enbridge undertake a best practice assessment? If so, please provide a copy of any best practice reports commissioned or reviewed.

b) Please provide any materials and presentations that Enbridge has that supports its decision to convert customers to e-bill without express consent.

c) Enbridge indicates that behavioral science supports using e-billing as a default option. Please explain if Enbridge believes that there is a difference between a default option for a new customer and switching an existing customer without consent. If so, please explain the difference.

Response

a) Enbridge Gas reviewed a number of studies on the topic including proprietary research completed by JD Power. Utilities across North America participate in the JD power research. The results from this research are confidential and only shared with the research participants. Due to the nature of the research a copy cannot be provided.

b) Please see Exhibit I.CCC.5 for the internal "business case" on the 2019 "Paperless Strategy".

c) Enbridge Gas believes that it is appropriate to use eBill as the default for all scenarios where the customer has provided an email address.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Pollution Probe

Interrogatory

Reference:

UAF Report

Question:

a) Please file a copy of the RFP and contract scope for the UAF Report.

b) Please provide a list of the firms that were considered for development of the UAF Report and the criteria for selecting Scott Madden Management Consultants.

c) Did ScottMadden Management Consultants identify "best practices" or just industry "practices"? If "best practices" were identified, please provide all material related to these best practices identified by ScottMadden Management Consultants.

d) Please provide all decks related to UAF provided by Scott Madden Management Consultants.

e) Please describe how carbon pricing is applied to UAF natural gas and how those costs are allocated to Ratepayers

f) The study indicated a legacy Union and legacy EGD average UFG level of 0.31 percent and 0.81 percent of gas receipts, respectively, over the past 10 years. Please provide the cumulative total dollar value of these UFG volumes.

g) Please provide an explanation why the "gas station meter variation" for legacy Enbridge is 33 times that of legacy Union.

h) Please provide an explanation of how Enbridge allocates UAF to Ratepayers vs. Affiliate transactions.

<u>Response</u>

a) Please see Attachment 1 for the Request for Quote and contract scope for the Unaccounted for Gas Report.

b) The firms that were considered for development of the Unaccounted for Gas report were:

- National Economic Research Associates (NERA)
- Christensen Associates Energy Consulting
- KPMG LLP
- London Economics International LLC
- Elenchus Research Associates
- Grant Thornton LLP
- BDO Canada LLP
- Concentric Energy Advisors
- MNP LLP
- Ernst and Young
- ICF International
- Pacific Economics Group Research, LLC
- ScottMadden Management Consultants

c) ScottMadden identified industry practices. ScottMadden's primary focus was to: (a) compare legacy Union Gas and legacy EGD's UFG levels to those in the industry; (b) compare the sources of UFG to those in the industry; and (c) compare the practices used to monitor and manage UFG to those in the industry.

d) ScottMadden's relevant research, analysis and findings are contained in the Report on Unaccounted for Gas submitted to the Ontario Energy Board.

e) The federal carbon charge is not applicable on UAF. Under the federal Greenhouse Gas Pollution Pricing Act, Enbridge Gas is only required to pay the federal carbon charge on the following quantities of natural gas: volumes used at company owned facilities, volumes used in company owned vehicles, and volumes delivered to customers who do not hold exemption certificates.

f)

	Legacy Union Gas		Legacy EGD	
	UFG	Cumulative UFG	UFG	Cumulative UFG
Year	$CDN	$CDN	$CDN	$CDN
2008	$56,241,846	$56,241,846	$13,398,496	$13,398,496
2009	$55,998,867	$112,240,713	$21,848,079	$35,246,575
2010	$17,263,561	$129,504,274	$17,692,816	$52,939,392
2011	$8,028,301	$137,532,575	$21,637,477	$74,576,869
2012	$12,902,646	$150,435,221	$15,478,819	$90,055,688
2013	$22,631,943	$173,067,164	$17,899,100	$107,954,787
2014	$18,429,387	$191,496,551	$27,615,027	$135,569,814
2015	$10,531,568	$202,028,118	$18,534,398	$154,104,212
2016	$18,510,324	$220,538,442	$22,368,047	$176,472,259
2017	$15,707,067	$236,245,509	$16,570,655	$193,042,914

g) Please see Exhibit I.EP.24 c).

h) For EGD rate zone customers, the cost of UFG is allocated to customers on a volumetric basis (i.e., each unit of consumption contributes to UFG). This approach reflects the Board-approved allocation methodology for the EGD rate zone and conceptually results in all bundled customers (i.e., every customer) paying the same unit rate to recover the cost of UFG. Unbundled customers (i.e., Rate 125 and 300 customers) are required to deliver UFG percentage to the Company in addition to their nominated gas delivery volume. This approach ensures that both bundled and unbundled customers are equally responsible to recover the cost of UFG.

For Union rate zones customers, the Board-approved methodology functionalizes the cost of UFG based on transmission and storage volumes. The transmission UFG is allocated based on ex-franchise and in-franchise transmission volumes. The storage UFG is allocated based on in-franchise storage injections and withdrawals.

Note that Enbridge Gas does not have a separate unit rate for UFG. The cost of UFG is recovered through Enbridge Gas's bundled delivery charges and unbundled fuel percentages in the EGD rate zone and delivery, transportation and storage charges (including fuel ratios) in the Union rate zones.

Enbridge Gas allocates UFG costs in a consistent manner by rate zone including rate classes that provide service to affiliate entities such as the EGD rate zone Rate 200: Wholesale Service, which provides distribution and upstream services to EGI affiliate Gazifère (natural gas distributor in the province of Quebec).

ENBRIDGE GAS INC.

REQUEST FOR QUOTE
Unaccounted for Gas Study

Scope of Services

1.0 OVERVIEW

1.1 **Overview** – Enbridge Gas Inc. ("**Enbridge**") is a Canadian natural gas utility regulated by the Ontario Energy Board ("**OEB**"). Enbridge provides natural gas distribution, transmission, storage and related services to approximately 3.7 million residential, commercial and industrial customers in over 400 communities in Ontario. Enbridge also provides natural gas storage and transmission services for other utilities and customers located outside of Enbridge's distribution service area.

On January 1, 2019, Union Gas Limited and Enbridge Gas Distribution were amalgamated to form Enbridge Gas Inc.

In its 2016 Earnings Sharing Mechanism proceeding (EB-2016-0142), Enbridge Gas Distribution agreed to review potential metering issues that might be contributing to Unaccounted for Gas and to report on that review. In its 2018 rates amended settlement proposal (EB-2017-0086), Enbridge Gas Distribution agreed to continue this review and report on the progress in the 2019 rate-setting application.

In response to an interrogatory in the application on the amalgamation of Enbridge Gas Distribution and Union Gas (EB-2017-0306 / EB-2017-0307), the applicants noted that the issue of Unaccounted for Gas would be addressed in the 2029 rebasing proceeding and not in 2019. The applicants were of the opinion that this issue is best considered and dependent on a comprehensive review within the eventual amalgamated entity and structure. In its final argument submission, OEB Staff did not see any convincing reason to delay the review until 2029. OEB Staff argued that if there are metering problems contributing to Unaccounted for Gas, the amalgamated company should review the issue, report to the OEB, and advise how the company intends to address the problem as part of its 2019 rates proceeding (or at the latest as part of the 2020 rates proceeding if there are timing issues).

In its Decision and Order dated August 30, 2018 in the EB-2017-0306 / EB-2017-0307 MAADs proceeding, the Ontario Energy Board stated that it considers the issue of Unaccounted for Gas important and directed Enbridge Gas Inc. to file a report on this issue for both the legacy Union Gas and legacy Enbridge Gas Distribution service areas by December 31, 2019.

Section 3.0 - Project Specifications (below) sets out the scope and purpose for the Unaccounted for Gas Study. Enbridge is requesting quotes from experienced consultants interested in completing the review as outlined in Section 3.0 - Project Specifications. The review must include all of the points listed in that Section 3.0.

1.2 **Deliverables** – The Consultant(s) selected by Enbridge to conduct the Unaccounted for Gas Study shall provide a report addressing each of the items noted in Section 3.0 - Project Specifications.

1.3 **Project Timing** – A draft report **<u>must</u>** be delivered to Enbridge by November 30, 2019.

2.0 Enbridge Gas Inc. Contact Information

2.1 Questions or correspondence regarding this request for quote should be submitted by August 23, 2019 to:

Mr. Patrick McMahon, Specialist, Regulatory Research and Records
EMAIL: patrick.mcmahon@enbridge.com

3.0 Project Specifications

3.1 The project includes the following items:

3.1.1 Conduct a statistical analysis of annual and monthly trends for Unaccounted for Gas for legacy Union Gas and legacy Enbridge Gas Distribution;

3.1.2 Prepare an analysis of Unaccounted for Gas causes and identify possible points of gas losses (e.g., meters and/or associated instrumentation, piping leakage, theft);

3.1.3 Review functional capabilities of the measurement system used to produce Unaccounted for Gas values;

3.1.4 Determine an industry benchmark of Unaccounted for Gas levels for companies with legacy Union Gas and legacy Enbridge Gas Distribution profile;

3.1.5 Review current and alternative Unaccounted for Gas forecasting and allocation methodologies;

3.1.6 Provide a written report that details the consultant's findings and presents recommendations, where appropriate and feasible on how to further reduce levels of Unaccounted for Gas (including costs / benefits analyses) by November 30, 2019; and

3.1.7 Provide expert evidence and/or expert witness testimony before the Ontario Energy Board as required.

3.2 Consultant shall describe its proposed process along with a detailed timeline, including (at a minimum) each of the following items:

3.2.1 Research and analysis process, including the methodology for:

- collection of information
- conducting meetings and communications
- conducting interviews

3.2.2 Report findings and recommendations, including:

- report structure and content
- supporting schedules

3.3 Consultant shall describe its expectations for Enbridge's responsibilities in supporting this project.

3.4 Consultant shall provide an all-inclusive price for the project for items 3.1.1 through 3.1.6 above, which shall include a breakdown showing the individual prices for each category of work as outlined. Pricing for item 3.1.7 should be quoted separately. The proposed terms of payment must be specified.

3.5 Consultant shall provide estimated timing to complete each aspect of the project as well as confirmation that the delivery of a draft and final report will meet the requirements of Section 1.3 - Project Timing.

4.0 Consultant Qualifications

4.1 The Consultant must have experience and expertise in statistical analysis and utility operations. Experience should be described and, at a minimum, the Consultant shall include specific references to previous work performed on these and related topics including for whom the work was performed, the nature of the work, the amount of time it took to complete and the contact information of references. For instances in which the Consultant participated in hearings before a regulatory body, details on the proceedings, the work performed and the outcomes of the proceeding should be provided. The Consultant may include other qualification information as appropriate.

4.2 The Consultant shall identify the Project Management team that will be assigned to the project and provide qualification summaries for each member. The Consultant shall also indicate the level of time each member of the team will be dedicated to this project.

5.0 Proposal Format and Submission

5.1 Qualified Consultants who wish to provide a quote for Enbridge's Unaccounted for Gas Study should email their submission by 3:00 pm EDT on August 30, 2019.

Please address quotes to:

Patrick McMahon, Specialist, Regulatory Research and Records
EMAIL: patrick.mcmahon@enbridge.com

5.0 CONSULTANT SELECTION

6.1 The selected Consultant, if any, will be advised by September 15, 2019.

7.0 Standard Terms and Conditions

7.1 Submission of a quote indicates a Consultant's agreement with Enbridge Gas Inc.'s Services Agreement, as attached.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Pollution Probe

Interrogatory

Reference:

UAF Report page 33

“Enbridge has an ongoing effort to identify and standardize “best practices” across the legacy Companies”.

Question:

a) Please provide a summary of the “best practices” Enbridge has identified and standardized across the legacy companies.

b) Please provide a summary of the “best practices” Enbridge has identified, but not yet standardized across the legacy companies.

c) Does Enbridge have a policy outlining the frequency of UAF review at the utility? If so, please provide a copy of this policy.

Response

a) The referenced section of the UFG report describes the practices and initiatives taken to monitor and manage retail meter variations as a potential source of UFG. The “best practices” Enbridge Gas has identified and standardized across the legacy companies to address these variations include Round Robin tests with participating CGA member’s facilities & Measurement Canada’s laboratory in Ottawa. Legacy Union Gas participated in the last Round Robin tests, while legacy EGD did not. Both legacy companies will be participating in 2020 Round Robin tests.

b) With respect to retail meter variations, the best practices address verification and re-verification of diaphragm, rotary and turbine meters as well as electronic volume integrators (EVIs). The Union and EGD rate zones have different processes for verification and reverification of all this measuring equipment. Enbridge Gas is reviewing these processes develop best practices to be implemented across the rate zones.

c) Enbridge Gas does not have a policy outlining the frequency of UFG review.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Pollution Probe

Interrogatory

Reference:

UAF Report pages 48 and 49

“Legacy Union’s UFG forecast is based on forecasted throughput volumes multiplied by a UFG ratio, currently approved by the Ontario Energy Board for rate-setting purposes to be 0.219 percent.”

“Legacy EGD uses a regression model to forecast the UFG which relies on the total number of unlocked customers as its primary explanatory variable to proxy for the size of the distribution system.”

Question:

a) Does Enbridge plan to harmonize the approach for forecasting UFG? If so, please explain which approach Enbridge intends to use and why this is the best approach for the combined utility.

b) In Phase 1 of this proceeding Enbridge confirmed that it will undertake an assessment of its regression model. Please confirm that use of the model for UFG will be in scope for this assessment.

Response

a) Please see Exhibit I.EP.26 d).

b) In Phase 1 of this proceeding Enbridge Gas confirmed that it will undertake an assessment of its average use/NAC models in its 2024 rebasing application[1]. The UFG forecast methodology will also be assessed in the rebasing application.

[1] EB-2019-0194, Exhibit N, Tab 1, Schedule 1, p.9

ENBRIDGE GAS INC.

Answer to Interrogatory from
Quinte Manufacturers Association ("QMA")

Interrogatory

Reference:

ScottMadden Report on Unaccounted for Gas ("UFG Report")

Question:

On page 8 of the UFG Report regarding *investments in facilities*, it suggests that "investments" will be made at industrial locations that will include the installation of "dual valves" to more accurately measure and record low-flow volumes at meters designed for large volume customers.

a) Please explain what dual valves are, how and where they are installed, and how they will improve the accuracy of measuring and recording volumes of meters currently installed at manufacturing plants.

b) Will Enbridge Gas Inc. own this equipment or will it be owned by the customer?

c) Please explain how will the cost for this new equipment be recovered from customers across the commercial rate classes?

Response

a) "Dual valves" are two on-off valves installed in series on a bypass line to a customer. The purpose of the second valve is to prevent delivery of unmeasured gas to the customer if the first valve is bypassed. Dual valves reduce unaccounted for gas by ensuring that all gas flows through the main line with the meter and not through the bypass line with no metering.

b) Enbridge Gas owns this equipment.

c) The costs of the valves will be included in Enbridge Gas' rate base and recovered in rates as part of the next rebasing proceeding. The cost of valves will be allocated to rate classes and recovered in rates in the same manner as other customer station related costs. Customer station related costs are recovered from rate classes as part of the monthly customer charge or demand charges (for rate classes without a monthly customer charge).

ENBRIDGE GAS INC.

Answer to Interrogatory from
Quinte Manufacturers Association ("QMA")

Interrogatory

Reference:

UFG Report

Question:

On page 27 of the UFG Report concerning *Processes and Procedures* please explain:

a) What is involved in conducting audits of manufacturing facilities based on failure trends and rollout of new products;

b) How have the failure trends been determined at manufacturing facilities to date, over what period of time, and in what area of legacy Union South; and

c) How will audit costs be recovered?

Response

a) Both Union and EGD rate zones have processes and procedures to evaluate material failures and maintain trend information such as the Material Fault Repair Program and the Procedure Equipment and Material Report Process. Based on the results of the testing of failed materials, an audit team comprised of representatives from Supply Chain and Engineering may be formed to evaluate a manufacturer's facilities. Additionally, both rate zones have processes in place to evaluate and approve the introduction of new materials. Teams may also evaluate a manufacturer's facility as needed focusing on a supplier's Quality Management Systems.

b) Failure trends are identified through the processes and procedures as referenced in part a). These processes and procedures have been in place for many years, apply to both rate zones across Ontario and are not region specific.

c) Costs incurred to support the auditing of the facilities are incurred as part of the normal operating costs and are not recovered separately (incrementally) from customers.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Quinte Manufacturers Association ("QMA")

Interrogatory

Reference:

UFG Report

Question:

On page 31 of the UFG Report concerning *Section V. Retail Meter Variations, Processes and Procedures*, at the fifth bullet point, please explain:

a) How and why would Enbridge Gas Inc. "Deploy internal controls associated with the Sarbanes-Oxley Act… to ensure accurate measurement and recording of volumes"; rather than the requirements of Government of Canada's Bill 198 (often referred to as "C-SOX") and regulations that apply within the same context?

Response

The ScottMadden UFG Report should have referenced C-SOX for Canadian reporting.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Quinte Manufacturers Association ("QMA")

Interrogatory

Reference:

Exhibit, Tab 3, Schedule 1, Pg. 9 of 29 (updated)

Question:

Paragraph 17 of the evidence states that in 2017 legacy Enbridge Gas Distribution initiated a customer experience program ("CX Program") to focus on how customers are served, but this has not yet been extended to legacy Union South customers. Further, the evidence indicates that extending the CX Program will be a priority of Enbridge Gas Inc. Please explain:

a) The timing of the rollout for legacy Union Gas customers in southeastern Ontario; and

b) What is the planned process that will be used to engage manufacturing and industrial customers in the legacy Union Gas South rate zone?

Response

a) The rollout will occur with the implementation of Enbridge Gas's SAP Customer Information System ("CIS") for all customers, currently expected in the second half of 2021.

b) The suite of myAccount features for manufacturing and industrial customers is rather limited versus mass market accounts. Extension to these customers will be considered in the future.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Quinte Manufacturers Association ("QMA")

Interrogatory

Reference:

Exhibit, Tab 3, Schedule 1, Pg. 20 of 29 (updated)

Question:

The evidence points to increased savings as the migration of customers from paper billing to eBilling continues. At paragraph 39, Table 3, eBill by rate class in Union Rate Zones, please explain:

a) Why is there such a low up-take in eBill usage in the commercial sector and is there a particular area of that sector that appears to be adopting e-Bill readily?

b) What action Enbridge Gas Inc. is going to take to improve the number of commercial customers switching to eBills in the Union Rate Zone and how quickly this activity will be rolled out; and,

c) Does the "commercial sector" referred to in Table 3 include customers in all areas of the manufacturing sector?

Response

a) Enbridge Gas current eBill practice prioritizes the residential experience and that likely impacts the interest that is seen from commercial customers. Enbridge Gas does not have any indication that there is one area of the commercial sector adopting eBill more readily than others.

b) Enbridge Gas's first action will be to migrate the Union Rate Zone commercial customers to share the same MyAccount platform as EGD Rate Zone customers, which is planned for Q3/Q4 2021. Once migrated, Enbridge Gas will assess the opportunities for service refinement and enhancements.

c) No. the "commercial sector" only includes small commercial properties which consume less than 75,000 cubic meters of gas.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Quinte Manufacturers Association ("QMA")

Interrogatory

Reference:

Exhibit, Tab 3, Schedule 1, Pg. 25 of 29 (updated)

Question:

Concerning the *Financial Benefits of Enbridge Gas's CX Program & E-Bill Practices*, paragraph 52 of the evidence indicates that the cost difference between paper billing and eBilling is approximately $10 per customer per year. Is this the approximate cost difference for the typical residential customer? Does this cost also reflect a similar cost difference for manufacturers or commercial customers? If not, please explain the difference.

Response

The cost difference realized from switching a customer to eBilling is similar for all customer types within Enbridge Gas.

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

[Ex. B/2/1, p. 4-5]

Question:

Please restate line 3, 2014-2023, in each of Tables 1 and 2 excluding all ICM projects applied for or to be applied for. Please identify all such ICM projects excluded, including in each case a reference to the leave to construct, if any, that has been granted or applied for. Please provide a description of the main reasons, other than ICM projects, for the dramatic upward trend of spending in this category.

Response

Below are the restated tables for line 3 excluding ICM projects. Please note that 2014-2018 represents a capital expenditure view, 2019-2023 is presented as in-service capital.

EGD Rate Zone	2014 Actual	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 Actual	2020 Budget	2021 Budget	2022 Budget	2023 Budget
System Renewal	96.5	102.7	109.1	102.2	92.3	125.1	143.4	145.3	143.2	169.9

Union Rate Zones	2014 Actual	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 Actual	2020 Budget	2021 Budget	2022 Budget	2023 Budget
System Renewal	83.8	73.0	76.3	87.6	102.5	120.1	126.7	113.2	112.4	107.0

Below are the ICM projects including the leave to construct where applicable:

EGD Rate Zone - ICM Eligible Projects	**Leave to Construct**	2020 Budget	2021 Budget	2022 Budget	2023 Budget
Don River NPS 30 Replacement	EB-2018-0108	25.4			
SCOR:Meter Area-Upgrade	Not filed		43.6		
NPS 12 St. Laurent Ottawa North Main Replacement (2021+)	Not filed			50.2	1.9
NPS 20 Lake Shore KOL Replacement (Cherry to Bathurst) (2019+)	Not filed			161.7	0.0

Union Rate Zones - ICM Eligible Projects	**Leave to Construct**	2020 Budget	2021 Budget	2022 Budget	2023 Budget
Windsor Line Replacement	EB-2019-0172	80.2	12.5		
LOND-London Lines Phase 1	Not filed		111.0	3.0	
Waubuno Compressor Upgrade	Not filed			19.6	1.4
Obsolete RB211-24A C Plant	Not filed				102.2

Variance Drivers

EGD Rate Zone – System Renewal spend is flat from 2014 to 2018. An increase is shown in 2019 due to additional main replacement, gate & feeder station and service relay work. An additional increase is forecasted for 2020 and 2023 related primarily to main replacements.

Union Rate Zones – System Renewal spend is flat until 2018. The increase in spend for 2019 is driven primarily by an increase in spend for the Integrity program. The additional increase in 2020 is due to an increase in spend related to the Bare and Unprotected Pipe program. Spend decreases and is flat from 2021-2023 as Integrity spend is reduced.

These increases over time are expected because the infrastructure in both rate zones are ageing and will require replacement. Investments in distribution, storage and compression assets is required to maintain safe and reliable operations.

ENBRIDGE GAS INC.

Answer to Interrogatory from
School Energy Coalition (“SEC”)

Interrogatory

Reference:

[Ex. B/2/1, p. 4]

Question:

Please provide a detailed breakdown of line 5, 2014-2023, both by category of overhead and category of capital spending to which it relates, in each case in sufficient detail for the Board and the parties to understand the large jump in capitalized overhead in 2020.

Response

Overheads	2014 Actual	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 Actual	2020 Budget	2021 Budget	2022 Budget	2023 Budget
DLC	90.6	88.6	93.2	92.6	88.2	94.9	99.1	88.7	90.2	93.2
A&G	35.2	38.4	43.1	36.7	35.9	34.0	41.3	35.6	37.1	38.4
IDC	3.9	3.8	5.0	4.0	3.0	3.3	2.3	2.4	2.5	2.6
EA Fixed OH	11.6	15.0	15.1	14.7	13.2	19.4	14.1	14.1	14.1	14.2
Total Overheads	141.3	145.9	156.4	148.1	140.2	151.6	156.8	140.8	143.9	148.4

The overheads by category are listed above. Note that 2014-2018 Actual reflects capital expenditures, 2019 - 2023 reflects in-service additions. Also note that the 2019 forecast has been updated to reflect 2019 actual. The Departmental Labour Charge (DLC) and Administrative & General (A&G) categories are driven by the amount of indirectly capitalized O&M and will vary from year to year based on O&M spend. The 2019 actual overheads are higher than forecasted due to an increase in O&M DLC overheads and higher EA fixed overheads. The increase in 2020 is driven primarily by the delay in the in-service capital for the Don River Replacement project.

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

[Ex. B/2/1, p. 4-5]

Question:

Please assume for the purpose of this interrogatory that natural gas volumes in the Applicant's franchise area will decline over the next forty years. Please provide all studies, memos, presentations, or other documentation in the possession of the Applicant dealing with the possibility that capital assets being added to rate base in current years will ultimately be stranded or underutilized assets before the end of their useful lives.

Response

Enbridge Gas does not have any studies, memos, presentations dealing with the possibility that capital assets being added to rate base in current years will ultimately be stranded or underutilized assets before the end of their useful lives.

This topic was discussed previously within the proceeding for the Panhandle Reinforcement Project (EB-2016-0186) in the Windsor area. Within that proceeding, legacy Union was asked about internal or external analyses or studies to assess potential stranded assets related to this issue, and legacy Union confirmed (at Exhibit B.BOMA.18d)) that it had not conducted any such analysis.

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

[Ex. B/2/1, p. 23-26]

Question:

Please provide details of all steps taken, and all studies and other analyses done (including copies of any such documentation), to reduce the peak demand served by the Windsor Line, now and in the future, in order to reduce its cost to ratepayers today.

Response

The need for the Windsor Line Replacement Project is being determined in the EB-2019-0172 proceeding. Please refer to EB-2019-0172, Exhibit C, Tab 3, Schedule 1, Section 3.5.7 for analysis completed.

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

[Ex. B/2/1, App. A, Table B]

Question:

Please provide a detailed explanation for the large increase in IT Implementation capital costs, starting in 2020 and continuing until 2023. Please explain how this increase interacts with the merger-related IT costs and provide details of those merger-related IT costs for each of those four years.

Response:

As noted in the response to Exhibit I.Staff.20 there has been a reduction to IT implementation ("TIS") capital costs for legacy Union for 2020. The major drivers of this change are outlined in the table provided in Exhibit I.Staff.20. However, as noted the reduction in TIS spending is offset by the advancement of the replacement of the Hamilton Gate Station ($6 million) and relocation work related to London Rapid Transit ($5.2 million).

For 2021 and beyond, the landscape has changed due to amalgamation. Enbridge Gas will be revising its planned investments from 2021-2030 and submitting details as part of the 10-year consolidated asset plan which will be submitted with the 2021 Rates Application.

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

[Ex. B/1/1/C, p. 2]

Question:

Please confirm that Enbridge plans to undertake a review of the cost allocation methodology of its entire system for its next rebasing application.

Response

Confirmed.

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

[Ex. B1/1/1/C]

Question:

Please provide a bill impact table showing the impact of the proposed new cost allocation methodology, if implemented in either a) 2020 or b) implemented in 2021.

Response

The estimated in-franchise bill impacts associated with the cost allocation study results are provided at Exhibit I.STAFF.4 part c). The annual bill impacts would not change materially (i.e. would remain approximately the same) if the cost allocation changes were implemented in 2020 or 2021.

Please see Exhibit I.STAFF.4 part b) for other considerations regarding implementing cost allocation changes in 2020 or 2021.

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

[Ex. B1/1/1/C]

Question:

Please provide a bill impact table showing the impact of the proposed new cost allocation methodology on EGD Rate Zone customer transportation costs, if implemented in either a) 2020 or b) estimated impact if implemented in 2021.

Response

As provided in response to Exhibit I.FRPO.19, Attachment 1, the impact of the proposed cost allocation methodology to EGD rate zone customers is a reduction in cost of approximately $10.2 million annually versus the current level of cost.

Attachment 1 provides estimated typical bill impacts (i.e., bill reductions) for EGD rate zone customers resulting from the cost allocation study directive, assuming all cost changes are adjusted in rates.

Most customers would experience bill impacts (reductions) within -0.1% to -0.5% range.

For a typical residential customer using 2,400 m^3 annually the estimated impact is an annual bill reduction of approximately $2.66 or -0.3%.

The estimated typical bill impacts for EGD rate zone customers would not change materially (i.e. would remain approximately the same) if the cost allocation changes were implemented in 2020 or 2021.

ANNUAL BILL COMPARISON - RESIDENTIAL CUSTOMERS

(A) ESTIMATE EB-2019-0273 vs (B) EB-2018-0273 BOARD APPROVED (JAN 1/2020 QRAM)

Item No.			Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8
			Heating & Water Htg.				Heating, Water Htg. & Other Uses			
			(A)	(B)	CHANGE		(A)	(B)	CHANGE	
					(A) - (B)	%			(A) - (B)	%
1.1	VOLUME	m³	3,064	3,064	0	0.0%	4,691	4,691	0	0.0%
1.2	CUSTOMER CHG.	$	245.75	245.75	0.00	0.0%	245.75	245.75	0.00	0.0%
1.3	DISTRIBUTION CHG.	$	261.99	264.59	(2.60)	-1.0%	395.04	398.94	(3.90)	-1.0%
1.4	LOAD BALANCING	§ $	170.73	171.50	(0.77)	-0.4%	261.39	262.59	(1.20)	-0.5%
1.5	SALES COMMDTY	$	286.45	286.45	0.00	0.0%	438.55	438.55	0.00	0.0%
1.6	TOTAL SALES	$	964.92	968.29	(3.37)	-0.3%	1,340.73	1,345.83	(5.10)	-0.4%
1.7	TOTAL T-SERVICE	$	678.47	681.84	(3.37)	-0.5%	902.18	907.28	(5.10)	-0.6%
1.8	SALES UNIT RATE	$/m³	0.3149	0.3160	(0.0011)	-0.3%	0.2858	0.2869	(0.0011)	-0.4%
1.9	T-SERVICE UNIT RATE	$/m³	0.2214	0.2225	(0.0011)	-0.5%	0.1923	0.1934	(0.0011)	-0.6%
1.10	SALES UNIT RATE	$/GJ	8.173	8.202	(0.0285)	-0.3%	7.418	7.446	(0.0282)	-0.4%
1.11	T-SERVICE UNIT RATE	$/GJ	5.747	5.776	(0.0285)	-0.5%	4.991	5.020	(0.0282)	-0.6%

			Heating Only				Heating & Water Htg.			
			(A)	(B)	CHANGE		(A)	(B)	CHANGE	
					(A) - (B)	%			(A) - (B)	%
2.1	VOLUME	m³	1,955	1,955	0	0.0%	2,005	2,005	0	0.0%
2.2	CUSTOMER CHG.	$	245.75	245.75	0.00	0.0%	245.75	245.75	0.00	0.0%
2.3	DISTRIBUTION CHG.	$	168.04	169.72	(1.68)	-1.0%	174.83	176.57	(1.74)	-1.0%
2.4	LOAD BALANCING	§ $	108.93	109.43	(0.50)	-0.5%	111.72	112.24	(0.52)	-0.5%
2.5	SALES COMMDTY	$	182.76	182.76	0.00	0.0%	187.43	187.43	0.00	0.0%
2.6	TOTAL SALES	$	705.48	707.66	(2.18)	-0.3%	719.73	721.99	(2.26)	-0.3%
2.7	TOTAL T-SERVICE	$	522.72	524.90	(2.18)	-0.4%	532.30	534.56	(2.26)	-0.4%
2.8	SALES UNIT RATE	$/m³	0.3609	0.3620	(0.0011)	-0.3%	0.3590	0.3601	(0.0011)	-0.3%
2.9	T-SERVICE UNIT RATE	$/m³	0.2674	0.2685	(0.0011)	-0.4%	0.2655	0.2666	(0.0011)	-0.4%
2.10	SALES UNIT RATE	$/GJ	9.366	9.395	(0.0289)	-0.3%	9.317	9.346	(0.0293)	-0.3%
2.11	T-SERVICE UNIT RATE	$/GJ	6.939	6.968	(0.0289)	-0.4%	6.890	6.920	(0.0293)	-0.4%

§ The Load Balancing Charge shown here includes proposed transportation charges

ANNUAL BILL COMPARISON - RESIDENTIAL CUSTOMERS

(A) ESTIMATE EB-2019-0273 vs (B) EB-2018-0273 BOARD APPROVED (JAN 1/2020 QRAM)

Item No.			Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8
			Heating, Pool Htg. & Other Uses				**General & Water Htg.**			
			(A)	**(B)**	**CHANGE**		**(A)**	**(B)**	**CHANGE**	
					(A) - (B)	%			(A) - (B)	%
3.1	VOLUME	m^3	5,048	5,048	0	0.0%	1,081	1,081	0	0.0%
3.2	CUSTOMER CHG.	$	245.75	245.75	0.00	0.0%	245.75	245.75	0.00	0.0%
3.3	DISTRIBUTION CHG.	$	424.89	429.07	(4.18)	-1.0%	98.61	99.62	(1.01)	-1.0%
3.4	LOAD BALANCING	§ $	281.29	282.57	(1.28)	-0.5%	60.23	60.51	(0.28)	-0.5%
3.5	SALES COMMDTY	$	471.93	471.93	0.00	0.0%	101.05	101.05	0.00	0.0%
3.6	TOTAL SALES	$	1,423.86	1,429.32	(5.46)	-0.4%	505.64	506.93	(1.29)	-0.3%
3.7	TOTAL T-SERVICE	$	951.93	957.39	(5.46)	-0.6%	404.59	405.88	(1.29)	-0.3%
3.8	SALES UNIT RATE	$/m³	0.2821	0.2831	(0.0011)	-0.4%	0.4677	0.4689	(0.0012)	-0.3%
3.9	T-SERVICE UNIT RATE	$/m³	0.1886	0.1897	(0.0011)	-0.6%	0.3743	0.3755	(0.0012)	-0.3%
3.10	SALES UNIT RATE	$/GJ	7.321	7.349	(0.0281)	-0.4%	12.140	12.171	(0.0310)	-0.3%
3.11	T-SERVICE UNIT RATE	$/GJ	4.894	4.922	(0.0281)	-0.6%	9.714	9.745	(0.0310)	-0.3%

			Heating & Water Htg.				**Heating & Water Htg.**			
			(A)	**(B)**	**CHANGE**		**(A)**	**(B)**	**CHANGE**	
					(A) - (B)	%			(A) - (B)	%
3.1	VOLUME	m^3	2,480	2,480	0	0.0%	2,400	2,400	0	0.0%
3.2	CUSTOMER CHG.	$	245.75	245.75	0.00	0.0%	245.75	245.75	0.00	0.0%
3.3	DISTRIBUTION CHG.	$	213.91	216.03	(2.12)	-1.0%	207.06	209.11	(2.05)	-1.0%
3.4	LOAD BALANCING	§ $	138.18	138.82	(0.64)	-0.5%	133.72	134.33	(0.61)	-0.5%
3.5	SALES COMMDTY	$	231.85	231.85	0.00	0.0%	224.37	224.37	0.00	0.0%
3.6	TOTAL SALES	$	829.69	832.45	(2.76)	-0.3%	810.90	813.56	(2.66)	-0.3%
3.7	TOTAL T-SERVICE	$	597.84	600.60	(2.76)	-0.5%	586.53	589.19	(2.66)	-0.5%
3.8	SALES UNIT RATE	$/m³	0.3346	0.3357	(0.0011)	-0.3%	0.3379	0.3390	(0.0011)	-0.3%
3.9	T-SERVICE UNIT RATE	$/m³	0.2411	0.2422	(0.0011)	-0.5%	0.2444	0.2455	(0.0011)	-0.5%
3.10	SALES UNIT RATE	$/GJ	8.683	8.712	(0.0289)	-0.3%	8.769	8.798	(0.0288)	-0.3%
3.11	T-SERVICE UNIT RATE	$/GJ	6.256	6.285	(0.0289)	-0.5%	6.343	6.372	(0.0288)	-0.5%

§ The Load Balancing Charge shown here includes proposed transportation charges

ANNUAL BILL COMPARISON - COMMERCIAL & INDUSTRIAL CUSTOMERS

(A) ESTIMATE EB-2019-0273 vs (B) EB-2018-0273 BOARD APPROVED (JAN 1/2020 QRAM)

Item No.			Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8
			Commercial Heating & Other Uses				**Com. Htg., Air Cond'ng & Other Uses**			
			(A)	(B)	CHANGE (A) - (B)	%	(A)	(B)	CHANGE (A) - (B)	%
1.1	VOLUME	m³	22,606	22,606	0	0.0%	29,278	29,278	0	0.0%
1.2	CUSTOMER CHG.	$	860.11	860.11	0.00	0.0%	860.11	860.11	0.00	0.0%
1.3	DISTRIBUTION CHG.	$	1,526.76	1,547.02	(20.26)	-1.3%	1,958.98	1,984.96	(25.98)	-1.3%
1.4	LOAD BALANCING	§ $	1,240.07	1,245.51	(5.44)	-0.4%	1,606.11	1,613.11	(7.00)	-0.4%
1.5	SALES COMMDTY	$	2,118.28	2,118.28	0.00	0.0%	2,743.49	2,743.49	0.00	0.0%
1.6	TOTAL SALES	$	5,745.22	5,770.92	(25.70)	-0.4%	7,168.69	7,201.67	(32.98)	-0.5%
1.7	TOTAL T-SERVICE	$	3,626.94	3,652.64	(25.70)	-0.7%	4,425.20	4,458.18	(32.98)	-0.7%
1.8	SALES UNIT RATE	$/m³	0.2541	0.2553	(0.0011)	-0.4%	0.2448	0.2460	(0.0011)	-0.5%
1.9	T-SERVICE UNIT RATE	$/m³	0.1604	0.1616	(0.0011)	-0.7%	0.1511	0.1523	(0.0011)	-0.7%
1.10	SALES UNIT RATE	$/GJ	6.596	6.626	(0.0295)	-0.4%	6.355	6.384	(0.0292)	-0.5%
1.11	T-SERVICE UNIT RATE	$/GJ	4.164	4.194	(0.0295)	-0.7%	3.923	3.952	(0.0292)	-0.7%

			Medium Commercial Customer				**Large Commercial Customer**			
			(A)	(B)	CHANGE (A) - (B)	%	(A)	(B)	CHANGE (A) - (B)	%
2.1	VOLUME	m³	169,563	169,563	0	0.0%	339,125	339,125	0	0.0%
2.2	CUSTOMER CHG.	$	860.11	860.11	0.00	0.0%	860.11	860.11	0.00	0.0%
2.3	DISTRIBUTION CHG.	$	8,234.94	8,344.29	(109.35)	-1.3%	15,085.43	15,285.80	(200.37)	-1.3%
2.4	LOAD BALANCING	§ $	9,301.67	9,342.35	(40.68)	-0.4%	18,603.27	18,684.63	(81.36)	-0.4%
2.5	SALES COMMDTY	$	15,888.83	15,888.83	0.00	0.0%	31,777.60	31,777.60	0.00	0.0%
2.6	TOTAL SALES	$	34,285.55	34,435.58	(150.03)	-0.4%	66,326.41	66,608.14	(281.73)	-0.4%
2.7	TOTAL T-SERVICE	$	18,396.72	18,546.75	(150.03)	-0.8%	34,548.81	34,830.54	(281.73)	-0.8%
2.8	SALES UNIT RATE	$/m³	0.2022	0.2031	(0.0009)	-0.4%	0.1956	0.1964	(0.0008)	-0.4%
2.9	T-SERVICE UNIT RATE	$/m³	0.1085	0.1094	(0.0009)	-0.8%	0.1019	0.1027	(0.0008)	-0.8%
2.10	SALES UNIT RATE	$/GJ	5.248	5.271	(0.0230)	-0.4%	5.076	5.098	(0.0216)	-0.4%
2.11	T-SERVICE UNIT RATE	$/GJ	2.816	2.839	(0.0230)	-0.8%	2.644	2.666	(0.0216)	-0.8%

§ The Load Balancing Charge shown here includes proposed transportation charges

ANNUAL BILL COMPARISON - COMMERCIAL & INDUSTRIAL CUSTOMERS

(A) ESTIMATE EB-2019-0273 vs (B) EB-2018-0273 BOARD APPROVED (JAN 1/2020 QRAM)

Item No.			Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8
			Industrial General Use				**Industrial Heating & Other Uses**			
			(A)	**(B)**	**CHANGE** (A) - (B)	%	**(A)**	**(B)**	**CHANGE** (A) - (B)	%
3.1	VOLUME	m³	43,285	43,285	0	0.0%	63,903	63,903	0	0.0%
3.2	CUSTOMER CHG.	$	860.11	860.11	0.00	0.0%	860.11	860.11	0.00	0.0%
3.3	DISTRIBUTION CHG.	$	2,707.59	2,743.51	(35.92)	-1.3%	3,633.00	3,681.23	(48.23)	-1.3%
3.4	LOAD BALANCING	§ $	2,374.46	2,384.84	(10.38)	-0.4%	3,505.51	3,520.82	(15.31)	-0.4%
3.5	SALES COMMDTY	$	4,056.02	4,056.02	0.00	0.0%	5,988.01	5,988.01	0.00	0.0%
3.6	TOTAL SALES	$	9,998.18	10,044.48	(46.30)	-0.5%	13,986.63	14,050.17	(63.54)	-0.5%
3.7	TOTAL T-SERVICE	$	5,942.16	5,988.46	(46.30)	-0.8%	7,998.62	8,062.16	(63.54)	-0.8%
3.8	SALES UNIT RATE	$/m³	0.2310	0.2321	(0.0011)	-0.5%	0.2189	0.2199	(0.0010)	-0.5%
3.9	T-SERVICE UNIT RATE	$/m³	0.1373	0.1383	(0.0011)	-0.8%	0.1252	0.1262	(0.0010)	-0.8%
3.10	SALES UNIT RATE	$/GJ	5.995	6.023	(0.0278)	-0.5%	5.681	5.706	(0.0258)	-0.5%
3.11	T-SERVICE UNIT RATE	$/GJ	3.563	3.591	(0.0278)	-0.8%	3.249	3.274	(0.0258)	-0.8%

Item No.			Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8
			Medium Industrial Customer				**Large Industrial Customer**			
			(A)	**(B)**	**CHANGE** (A) - (B)	%	**(A)**	**(B)**	**CHANGE** (A) - (B)	%
4.1	VOLUME	m³	169,563	169,563	0	0.0%	339,124	339,124	0	0.0%
4.2	CUSTOMER CHG.	$	860.11	860.11	0.00	0.0%	860.11	860.11	0.00	0.0%
4.3	DISTRIBUTION CHG.	$	8,431.87	8,543.81	(111.94)	-1.3%	15,231.93	15,434.22	(202.29)	-1.3%
4.4	LOAD BALANCING	§ $	9,301.67	9,342.35	(40.68)	-0.4%	18,603.22	18,684.59	(81.37)	-0.4%
4.5	SALES COMMDTY	$	15,888.85	15,888.85	0.00	0.0%	31,777.49	31,777.49	0.00	0.0%
4.6	TOTAL SALES	$	34,482.50	34,635.12	(152.62)	-0.4%	66,472.75	66,756.41	(283.66)	-0.4%
4.7	TOTAL T-SERVICE	$	18,593.65	18,746.27	(152.62)	-0.8%	34,695.26	34,978.92	(283.66)	-0.8%
4.8	SALES UNIT RATE	$/m³	0.2034	0.2043	(0.0009)	-0.4%	0.1960	0.1968	(0.0008)	-0.4%
4.9	T-SERVICE UNIT RATE	$/m³	0.1097	0.1106	(0.0009)	-0.8%	0.1023	0.1031	(0.0008)	-0.8%
4.10	SALES UNIT RATE	$/GJ	5.278	5.301	(0.0234)	-0.4%	5.087	5.109	(0.0217)	-0.4%
4.11	T-SERVICE UNIT RATE	$/GJ	2.846	2.869	(0.0234)	-0.8%	2.655	2.677	(0.0217)	-0.8%

§ The Load Balancing Charge shown here includes proposed transportation charges

ANNUAL BILL COMPARISON - LARGE VOLUME CUSTOMERS

(A) ESTIMATE EB-2019-0273 vs (B) EB-2018-0273 BOARD APPROVED (JAN 1/2020 QRAM)

Item No.			Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8
			Rate 100 - Small Commercial Firm				**Rate 100 - Average Commercial Firm**			
			(A)	**(B)**	**CHANGE** (A) - (B)	%	**(A)**	**(B)**	**CHANGE** (A) - (B)	%
1.1	VOLUME	m³	339,188	339,188	0	0.0%	598,567	598,567	0	0.0%
1.2	CUSTOMER CHG.	$	1,499.17	1,499.17	0.00	0.0%	1,499.17	1,499.17	0.00	0.0%
1.3	DISTRIBUTION CHG.	$	13,833.83	13,833.93	(0.10)	0.0%	67,400.44	67,400.56	(0.12)	0.0%
1.4	LOAD BALANCING	$	18,606.74	18,688.10	(81.36)	-0.4%	32,835.43	32,979.01	(143.58)	-0.4%
1.5	SALES COMMDTY	$	31,783.48	31,783.48	0.00	0.0%	56,088.48	56,088.48	0.00	0.0%
1.6	TOTAL SALES	$	65,723.22	65,804.69	(81.46)	-0.1%	157,823.52	157,967.22	(143.70)	-0.1%
1.7	TOTAL T-SERVICE	$	33,939.74	34,021.21	(81.46)	-0.2%	101,735.04	101,878.74	(143.70)	-0.1%
1.8	SALES UNIT RATE	$/m³	0.1938	0.1940	(0.0002)	-0.1%	0.2637	0.2639	(0.0002)	-0.1%
1.9	T-SERVICE UNIT RATE	$/m³	0.1001	0.1003	(0.0002)	-0.2%	0.1700	0.1702	(0.0002)	-0.1%
1.10	SALES UNIT RATE	$/GJ	5.0290	5.0352	(0.0062)	-0.1%	6.8432	6.8494	(0.0062)	-0.1%
1.11	T-SERVICE UNIT RATE	$/GJ	2.5970	2.6032	(0.0062)	-0.2%	4.4112	4.4175	(0.0062)	-0.1%

Rate 100 - Large Industrial Firm

			(A)	**(B)**	**CHANGE** (A) - (B)	%
2.1	VOLUME	m³	1,500,000	1,500,000	0	0.0%
2.2	CUSTOMER CHG.	$	1,499.17	1,499.17	0.00	0.0%
2.3	DISTRIBUTION CHG.	$	135,331.52	135,331.84	(0.32)	0.0%
2.4	LOAD BALANCING	$	82,285.08	82,644.91	(359.83)	-0.4%
2.5	SALES COMMDTY	$	140,556.96	140,556.96	0.00	0.0%
2.6	TOTAL SALES	$	359,672.74	360,032.88	(360.15)	-0.1%
2.7	TOTAL T-SERVICE	$	219,115.78	219,475.92	(360.15)	-0.2%
2.8	SALES UNIT RATE	$/m³	0.2398	0.2400	(0.0002)	-0.1%
2.9	T-SERVICE UNIT RATE	$/m³	0.1461	0.1463	(0.0002)	-0.2%
2.10	SALES UNIT RATE	$/GJ	6.2233	6.2295	(0.0062)	-0.1%
2.11	T-SERVICE UNIT RATE	$/GJ	3.7913	3.7975	(0.0062)	-0.2%

ANNUAL BILL COMPARISON - LARGE VOLUME CUSTOMERS

(A) ESTIMATE EB-2019-0273 vs (B) EB-2018-0273 BOARD APPROVED (JAN 1/2020 QRAM)

Item No.			Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8
			Rate 145 - Small Commercial Interr.				**Rate 145 - Average Commercial Interr.**			
			(A)	(B)	CHANGE		(A)	(B)	CHANGE	
					(A) - (B)	%			(A) - (B)	%
3.1	VOLUME	m³	339,188	339,188	0	0.0%	598,568	598,568	0	0.0%
3.2	CUSTOMER CHG.	$	1,515.51	1,515.51	0.00	0.0%	1,515.51	1,515.51	0.00	0.0%
3.3	DISTRIBUTION CHG.	$	12,494.40	12,542.91	(48.51)	-0.4%	18,944.12	19,029.73	(85.61)	-0.4%
3.4	LOAD BALANCING	$	14,640.46	14,690.62	(50.16)	-0.3%	25,836.52	25,925.06	(88.54)	-0.3%
3.5	SALES COMMDTY	$	31,601.16	31,601.16	0.00	0.0%	55,766.83	55,766.83	0.00	0.0%
3.6	TOTAL SALES	$	60,251.53	60,350.20	(98.67)	-0.2%	102,062.98	102,237.13	(174.15)	-0.2%
3.7	TOTAL T-SERVICE	$	28,650.37	28,749.04	(98.67)	-0.3%	46,296.15	46,470.30	(174.15)	-0.4%
3.8	SALES UNIT RATE	$/m³	0.1776	0.1779	(0.0003)	-0.2%	0.1705	0.1708	(0.0003)	-0.2%
3.9	T-SERVICE UNIT RATE	$/m³	0.0845	0.0848	(0.0003)	-0.3%	0.0773	0.0776	(0.0003)	-0.4%
3.10	SALES UNIT RATE	$/GJ	4.6103	4.6178	(0.0075)	-0.2%	4.4254	4.4330	(0.0076)	-0.2%
3.11	T-SERVICE UNIT RATE	$/GJ	2.1923	2.1998	(0.0075)	-0.3%	2.0074	2.0149	(0.0076)	-0.4%

			Rate 145 - Small Industrial Interr.				**Rate 145 - Average Industrial Interr.**			
			(A)	(B)	CHANGE		(A)	(B)	CHANGE	
					(A) - (B)	%			(A) - (B)	%
4.1	VOLUME	m³	339,188	339,188	0	0.0%	598,567	598,567	0	0.0%
4.2	CUSTOMER CHG.	$	1,515.51	1,515.51	0.00	0.0%	1,515.51	1,515.51	0.00	0.0%
4.3	DISTRIBUTION CHG.	$	12,770.21	12,818.71	(48.50)	-0.4%	19,188.26	19,273.87	(85.61)	-0.4%
4.4	LOAD BALANCING	$	14,640.44	14,690.61	(50.17)	-0.3%	25,836.47	25,925.02	(88.55)	-0.3%
4.5	SALES COMMDTY	$	31,601.13	31,601.13	0.00	0.0%	55,766.74	55,766.74	0.00	0.0%
4.6	TOTAL SALES	$	60,527.29	60,625.96	(98.67)	-0.2%	102,306.98	102,481.14	(174.16)	-0.2%
4.7	TOTAL T-SERVICE	$	28,926.16	29,024.83	(98.67)	-0.3%	46,540.24	46,714.40	(174.16)	-0.4%
4.8	SALES UNIT RATE	$/m³	0.1784	0.1787	(0.0003)	-0.2%	0.1709	0.1712	(0.0003)	-0.2%
4.9	T-SERVICE UNIT RATE	$/m³	0.0853	0.0856	(0.0003)	-0.3%	0.0778	0.0780	(0.0003)	-0.4%
4.10	SALES UNIT RATE	$/GJ	4.6314	4.6389	(0.0075)	-0.2%	4.4360	4.4436	(0.0076)	-0.2%
4.11	T-SERVICE UNIT RATE	$/GJ	2.2134	2.2209	(0.0075)	-0.3%	2.0180	2.0255	(0.0076)	-0.4%

ANNUAL BILL COMPARISON - LARGE VOLUME CUSTOMERS

(A) ESTIMATE EB-2019-0273 vs (B) EB-2018-0273 BOARD APPROVED (JAN 1/2020 QRAM)

Item No.			Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8
			Rate 110 - Small Ind. Firm - 50% LF				Rate 110 - Average Ind. Firm - 50% LF			
			(A)	(B)	CHANGE		(A)	(B)	CHANGE	
					(A) - (B)	%			(A) - (B)	%
5.1	VOLUME	m³	598,568	598,568	0	0.0%	9,976,121	9,976,121	0	0.0%
5.2	CUSTOMER CHG.	$	7,217.18	7,217.18	0.00	0.0%	7,217.18	7,217.18	0.00	0.0%
5.3	DISTRIBUTION CHG.	$	14,255.69	14,296.56	(40.87)	-0.3%	233,718.01	234,399.00	(680.99)	-0.3%
5.4	LOAD BALANCING	$	27,336.06	27,399.91	(63.85)	-0.2%	455,600.47	456,664.70	(1,064.23)	-0.2%
5.5	SALES COMMDTY	$	55,744.78	55,744.78	0.00	0.0%	929,078.29	929,078.29	0.00	0.0%
5.6	TOTAL SALES	$	104,553.71	104,658.43	(104.72)	-0.1%	1,625,613.95	1,627,359.17	(1,745.22)	-0.1%
5.7	TOTAL T-SERVICE	$	48,808.93	48,913.65	(104.72)	-0.2%	696,535.66	698,280.88	(1,745.22)	-0.2%
5.8	SALES UNIT RATE	$/m³	0.1747	0.1748	(0.0002)	-0.1%	0.1630	0.1631	(0.0002)	-0.1%
5.9	T-SERVICE UNIT RATE	$/m³	0.0815	0.0817	(0.0002)	-0.2%	0.0698	0.0700	(0.0002)	-0.2%
###	SALES UNIT RATE	$/GJ	4.5334	4.5380	-0.0045	-0.1%	4.2292	4.2337	-0.0045	-0.1%
###	T-SERVICE UNIT RATE	$/GJ	2.1163	2.1209	-0.0045	-0.2%	1.8121	1.8166	-0.0045	-0.2%

Item No.			Rate 110 - Average Ind. Firm - 75% LF				Rate 115 - Large Ind. Firm - 80% LF			
			(A)	(B)	CHANGE		(A)	(B)	CHANGE	
					(A) - (B)	%			(A) - (B)	%
6.1	VOLUME	m³	9,976,120	9,976,120	0	0.0%	69,832,850	69,832,850	0	0.0%
6.2	CUSTOMER CHG.	$	7,217.18	7,217.18	0.00	0.0%	7,650.31	7,650.31	0.00	0.0%
6.3	DISTRIBUTION CHG.	$	185,647.91	186,328.87	(680.96)	-0.4%	979,095.96	981,522.98	(2,427.02)	-0.2%
6.4	LOAD BALANCING	$	455,600.45	456,664.67	(1,064.22)	-0.2%	3,086,507.93	3,092,175.99	(5,668.06)	-0.2%
6.5	SALES COMMDTY	$	929,078.19	929,078.19	0.00	0.0%	6,503,548.26	6,503,548.26	0.00	0.0%
6.6	TOTAL SALES	$	1,577,543.73	1,579,288.91	(1,745.18)	-0.1%	10,576,802.46	10,584,897.54	(8,095.08)	-0.1%
6.7	TOTAL T-SERVICE	$	648,465.54	650,210.72	(1,745.18)	-0.3%	4,073,254.20	4,081,349.28	(8,095.08)	-0.2%
6.8	SALES UNIT RATE	$/m³	0.1581	0.1583	(0.0002)	-0.1%	0.1515	0.1516	(0.0001)	-0.1%
6.9	T-SERVICE UNIT RATE	$/m³	0.0650	0.0652	(0.0002)	-0.3%	0.0583	0.0584	(0.0001)	-0.2%
###	SALES UNIT RATE	$/GJ	4.1041	4.1087	(0.0045)	-0.1%	3.9309	3.9339	(0.0030)	-0.1%
###	T-SERVICE UNIT RATE	$/GJ	1.6870	1.6916	(0.0045)	-0.3%	1.5138	1.5169	(0.0030)	-0.2%

ANNUAL BILL COMPARISON - LARGE VOLUME CUSTOMERS

(A) ESTIMATE EB-2019-0273 vs (B) EB-2018-0273 BOARD APPROVED (JAN 1/2020 QRAM)

Item No.			Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8
			Rate 135 - Seasonal Firm				**Rate 170 - Average Ind. Interr. - 50% LF**			
			(A)	**(B)**	**CHANGE**		**(A)**	**(B)**	**CHANGE**	
					(A) - (B)	%			(A) - (B)	%
7.1	VOLUME	m³	598,567	598,567	0	0.0%	9,976,121	9,976,121	0	0.0%
7.2	CUSTOMER CHG.	$	1,414.02	1,414.02	-	0.0%	3,431.96	3,431.96	-	0.0%
7.3	DISTRIBUTION CHG.	$	10,927.84	10,929.13	(1.29)	0.0%	79,792.94	80,444.68	(651.74)	-0.8%
7.4	LOAD BALANCING	$	20,870.03	20,912.05	(42.02)	-0.2%	334,807.32	335,855.45	(1,048.13)	-0.3%
7.5	SALES COMMDTY	$	55,787.59	55,787.59	-	0.0%	929,078.28	929,078.28	-	0.0%
7.6	TOTAL SALES	$	88,999.48	89,042.79	(43.31)	0.0%	1,347,110.50	1,348,810.37	(1,699.87)	-0.1%
7.7	TOTAL T-SERVICE	$	33,211.89	33,255.20	(43.31)	-0.1%	418,032.22	419,732.09	(1,699.87)	-0.4%
7.8	SALES UNIT RATE	$/m³	0.1487	0.1488	(0.0001)	0.0%	0.1350	0.1352	(0.0002)	-0.1%
7.9	T-SERVICE UNIT RATE	$/m³	0.0555	0.0556	(0.0001)	-0.1%	0.0419	0.0421	(0.0002)	-0.4%
7.10	SALES UNIT RATE	$/GJ	3.8590	3.8609	(0.0019)	0.0%	3.5046	3.5091	(0.0044)	-0.1%
7.11	T-SERVICE UNIT RATE	$/GJ	1.4401	1.4419	(0.0019)	-0.1%	1.0875	1.0920	(0.0044)	-0.4%

			Rate 170 - Average Ind. Interr. - 75% LF				**Rate 170 - Large Ind. Interr. - 75% LF**			
			(A)	**(B)**	**CHANGE**		**(A)**	**(B)**	**CHANGE**	
					(A) - (B)	%			(A) - (B)	%
8.1	VOLUME	m³	9,976,120	9,976,120	0	0.0%	69,832,850	69,832,850	0	0.0%
8.2	CUSTOMER CHG.	$	3,431.96	3,431.96	-	0.0%	3,431.96	3,431.96	-	0.0%
8.3	DISTRIBUTION CHG.	$	72,424.57	73,076.33	(651.76)	-0.9%	389,606.33	394,168.57	(4,562.24)	-1.2%
8.4	LOAD BALANCING	$	334,807.28	335,855.41	(1,048.13)	-0.3%	2,343,651.39	2,350,988.22	(7,336.83)	-0.3%
8.5	SALES COMMDTY	$	929,078.19	929,078.19	-	0.0%	6,503,548.26	6,503,548.26	-	0.0%
8.6	TOTAL SALES	$	1,339,742.00	1,341,441.89	(1,699.89)	-0.1%	9,240,237.94	9,252,137.01	(11,899.07)	-0.1%
8.7	TOTAL T-SERVICE	$	410,663.81	412,363.70	(1,699.89)	-0.4%	2,736,689.68	2,748,588.75	(11,899.07)	-0.4%
8.8	SALES UNIT RATE	$/m³	0.1343	0.1345	(0.0002)	-0.1%	0.1323	0.1325	(0.0002)	-0.1%
8.9	T-SERVICE UNIT RATE	$/m³	0.0412	0.0413	(0.0002)	-0.4%	0.0392	0.0394	(0.0002)	-0.4%
8.10	SALES UNIT RATE	$/GJ	3.4855	3.4899	(0.0044)	-0.1%	3.4342	3.4386	(0.0044)	-0.1%
8.11	T-SERVICE UNIT RATE	$/GJ	1.0684	1.0728	(0.0044)	-0.4%	1.0171	1.0215	(0.0044)	-0.4%

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

[Ex. B1/1/1/C, p.12]

Question:

Please explain how the proposed changes to the Panhandle and St. Clair systems differ from what Union Gas had proposed as part of the EB-2016-0186 proceeding.

Response

As part of the EB-2016-0186 proceeding, Union proposed an interim allocation of the Panhandle System demand costs of the Panhandle Reinforcement Project in proportion to the firm Union South in-franchise Panhandle System design day demands, updated to include the incremental firm Project design day demands. The allocation of existing Panhandle System and St. Clair System demand costs were proposed to be maintained in proportion to the 2013 Board-approved allocation methodology for Ojibway / St. Clair Demand costs. Union had also stated that it would review the cost allocation and rate design of these systems as part of its 2019 Cost of Service proceeding.

The proposed cost allocation methodology as part of this application separates the Ojibway / St. Clair functional classification into new Panhandle Demand and St. Clair Demand functional classifications.

The proposed cost allocation methodology of the Panhandle Demand functional classification is based on the use of each asset on the Panhandle System. First, Enbridge Gas proposes to direct assign the costs of assets used solely to serve ex-franchise Rate C1, which includes the costs of the Sandwich Compressor station and Ojibway measurement station. The proposed direct assignment also includes an allocation of transmission mains and Dawn yard assets to Rate C1 and Rate M16 using a proportional allocation based on 214 days use of contracted capacity to the total design day demands of the Panhandle System. The remaining Panhandle transmission mains and Dawn yard asset costs are proposed to be allocated to Union South rate classes in proportion to the forecast Panhandle System design day demands.

The proposed cost allocation methodology of the St. Clair Demand functional classification is to direct assign all costs to Rate C1.

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

[Ex. B1/1/1/C, p.12-13]

Question:

Please describe what specific Dawn yard assets are directly allocated to the Panhandle System.

Response

Compression-related assets at Dawn are functionalized to the Panhandle System in proportion to the horsepower requirements at Dawn on design day required to flow gas into the Panhandle System. In addition, a portion of measuring and regulating assets at Dawn are functionalized to the Panhandle System based on an analysis of total activity at Dawn.

Dawn yard assets functionalized to the Panhandle System total $4.371 million ($8.893 million cost net of $4.522 million accumulated depreciation). Please see Exhibit B, Tab 1, Appendix C1, Schedule 1.1, Cell S29 and Cell S102.

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

[Ex. B2/2/1]

Question:

For each of the Don River Replacement and Windsor Line Replacement Projects:

Please complete the below table.

Project Costs			
	Latest Estimates Available	EB-2019-0194 Application	Leave to Construct Application
Materials			
Construction and Labor			
Contingencies			
IDC			
Subtotal			
Indirect Overhead			
Total			

Please provide a detailed explanation of all variances and explain why any costs increases are reasonable.

Response

Please see Exhibit I.BOMA.6 for cost estimates related to the Don River Replacement Project.

Please see the table below for cost estimates related to the Windsor Line Replacement Project.

	Latest Estimates Available	**EB-2019-0194 Application**	**Leave to Construct Application**
Materials	$5,869,000	$5,869,000	$5,869,000
Construction and Labour	$74,067,000	$74,067,000	$74,067,000
Contingencies	$11,963,000	$11,963,000	$11,963,000
Interest During Construction	$845,000	$845,000	$845,000
Estimated Incremental Project Capital Costs	**$92,744,000**	**$92,744,000**	**$92,744,000**
Indirect Overhead	$14,061,000	$14,061,000	$14,061,000
Total Estimated Project Capital Costs	**$106,805,000**	**$106,805,000**	**$106,805,000**

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

[Ex. B/2/1, p. 19]

Question:

With respect to the Windsor Line Replacement Project:

a) Please explain what would happen if the Board approves the ICM for the project, but subsequently denies the leave to construct application.

b) [EB-2019-0172, C-5-1] Please provide a copy of the project schedule included in the leave to construct application.

c) Please provide the most recent available project schedule.

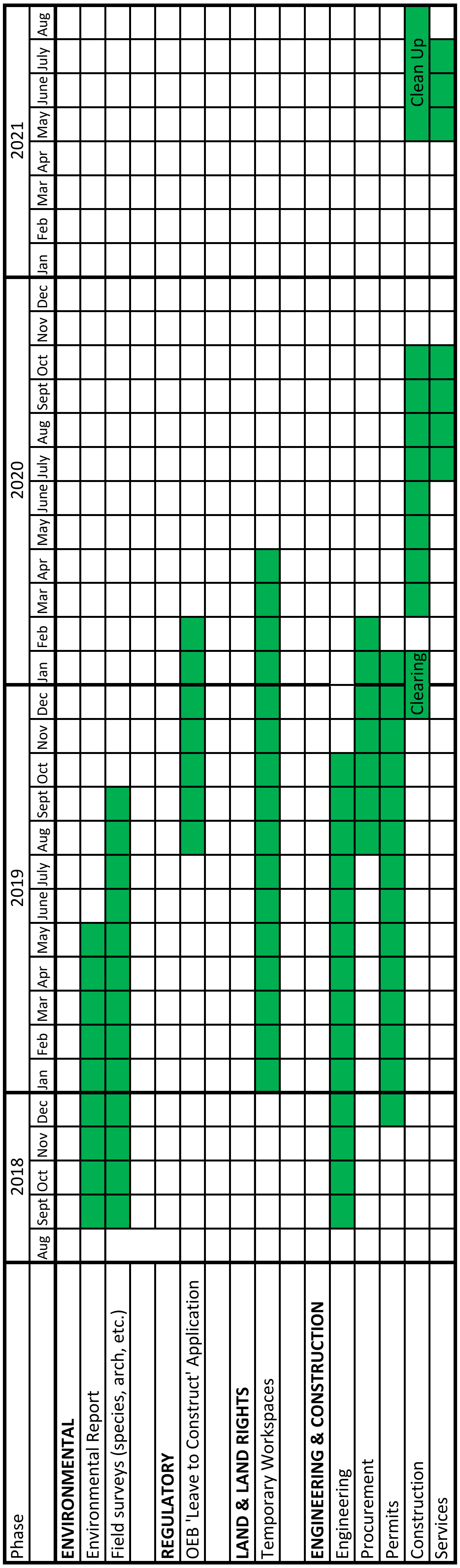
Response

a) Please see the response at Exhibit I.STAFF.7.

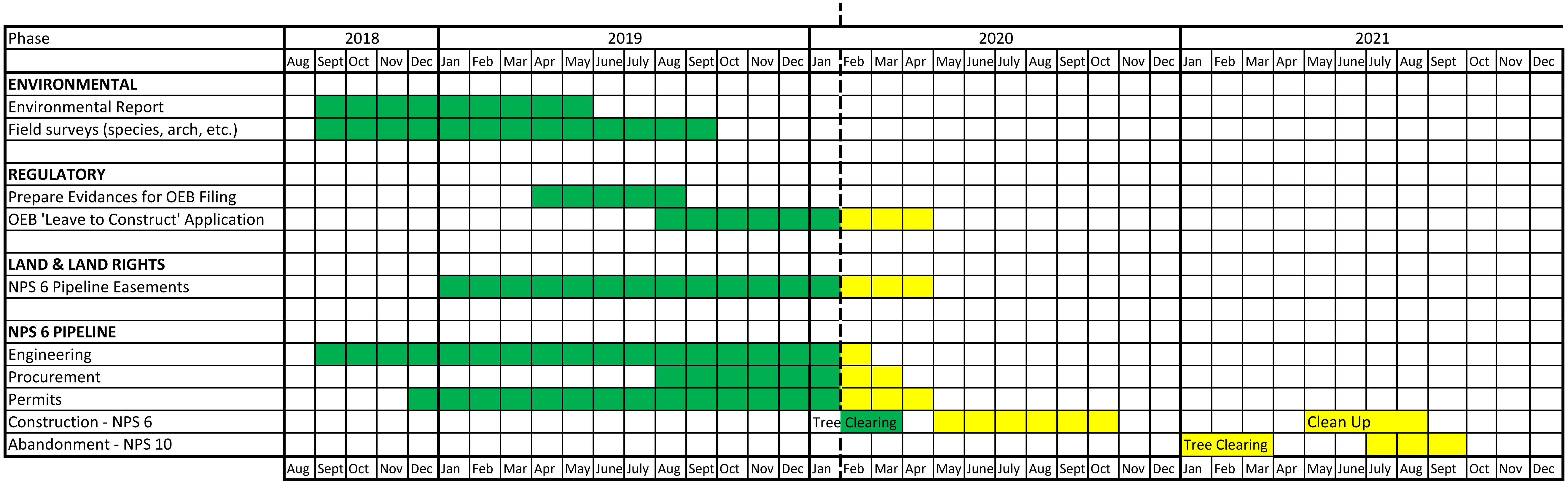
b) Please see Attachment 1 for a copy of the project schedule filed as part of the EB-2019-0172 Windsor Line Replacement Project leave to construct application.

c) Please see Attachment 2 for a copy of the most recent available project schedule for the Windsor Line Replacement Project.

PROPOSED PROJECT SCHEDULE



WINDOR LINE REPLACEMENT PROJECT SCHEDULE



ENBRIDGE GAS INC.

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

Interrogatory

Reference:

[UFG Report, p. 16-17]

Question:

Please provide Figure 5 and 6 in a tabular format.

Response

Please see Attachments 1 and 2.

Year	U.S. Utilities	Comparison Group	East North Central	Canadian Utilities	Legacy EGD	Legacy Union
2008	1.06%	1.88%	1.80%	1.41%	0.37%	0.41%
2009	1.49%	1.08%	0.65%	1.23%	0.97%	0.64%
2010	1.01%	1.02%	0.72%	1.05%	0.66%	0.19%
2011	0.88%	0.97%	0.77%	1.68%	0.64%	0.11%
2012	0.90%	0.97%	0.76%	0.94%	0.71%	0.21%
2013	1.21%	1.48%	1.18%	1.14%	0.83%	0.32%
2014	0.69%	0.58%	0.51%	0.83%	1.09%	0.32%
2015	0.84%	0.62%	0.45%	0.97%	0.81%	0.17%
2016	1.34%	1.46%	1.14%	1.75%	1.18%	0.43%
2017	1.18%	1.40%	1.05%	0.81%	0.80%	0.34%
Average	**1.06%**	**1.15%**	**0.90%**	**1.18%**	**0.81%**	**0.31%**
% of US Average					76.0%	34.8%
% of Regional Average					89.4%	26.5%
% of Canadian Average					68.2%	38.9%

Year	U.S. Utilities	Comparison Group	East North Central	Canadian Utilities	Legacy EGD	Legacy Union
2008	100%	164%	200%	120%	46%	131%
2009	141%	94%	72%	104%	120%	203%
2010	96%	89%	80%	89%	82%	61%
2011	83%	85%	85%	142%	79%	34%
2012	85%	84%	84%	80%	88%	67%
2013	114%	129%	131%	96%	103%	102%
2014	65%	51%	57%	70%	135%	101%
2015	79%	54%	50%	82%	101%	55%
2016	127%	128%	127%	148%	146%	136%
2017	111%	123%	116%	69%	99%	109%
Average	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
% of US Average					100.0%	100.0%
% of Regional Average					100.0%	100.0%
% of Canadian Average					100.0%	100.0%

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

[UFG Report, p. 47]

Question:

Please provide Enbridge's response to the recommendations contained in the report and its plan to implement them.

Response

Please see Exhibit I.STAFF.27.

ENBRIDGE GAS INC.

Answer to Interrogatory from
TransCanada PipeLines Limited ("TCPL")

INTERROGATORY

Reference:

1) Exhibit B, Tab 1, Schedule 1, Appendix C, Pages 2-4 of 30.
2) Exhibit B, Tab 1, Schedule 1, Appendix C, Table 1, Page 5 of 30.
3) Exhibit B, Tab 1, Schedule 1, Appendix C, Page 6 of 30.
4) Exhibit B, Tab 1, Schedule 1, Appendix C, Pages 23-24 of 30.

Preamble:

In Reference 1, EGI indicates that while it is seeking Board approval of the cost allocation methodology changes as part of the present application, it is not proposing to implement the cost allocation methodology changes until its next rebasing proceeding, and it is not recommending changes to the pre-filed rates for 2020.

In Reference 1, EGI states that it anticipates there will be additional changes at rebasing in 2024 when EGI introduces rate harmonization and integration of the cost allocation studies for the combined utility. EGI also states that implementation of cost allocation changes by rate class without consideration of rate design factors may result in unintended impacts that cannot be predicted without a complete rate design review similar to what is completed as part of a cost of service proceeding.

In Reference 2, Table 1 provides dollar impacts of the Cost Allocation Study proposals by rate class.

In Reference 3, EGI states that the revenue deficiency/sufficiency in Table 1 does not reflect the final rate adjustment that may occur as part of a cost of service proceeding as such adjustment would include rate design and other adjustments that may be required to manage revenue to cost ratios, maintain rate class continuity and address bill impacts.

In Reference 4, EGI provides revenue to cost ratios that compare the company's revenue based on approved 2019 rates to the 2019 revenue requirement by rate class. The revenue to cost ratios illustrate the variance between revenue, calculated at current approved rates, and the fully allocated cost allocation study. Table 3 provides revenue to cost ratios including and excluding the proposed cost allocation methodologies. EGI states that the revenue to cost ratios do not indicate the final rate adjustment that may occur as part of a cost of service proceeding as the ratios do not include any adjustments for rate design and other adjustments that may be required to maintain rate class continuity and address bill impacts.

Question:

a) As part of its next rebasing proceeding for 2024, does EGI intend on filing a full system-wide cost allocation study that will review the allocation of all costs in both the EGD and Union Rate Zones, including costs at Parkway Station? If not confirmed, please explain why not and when such a study will be filed.

b) Please provide all of the unit rate impacts ($/GJ) for M12, M12-X and C1 rate classes by transportation path for each of the proposed cost allocation changes in the Cost Allocation Study (Panhandle/St. Clair, Parkway Station, Dawn Station) assuming "no rate design and other adjustments" are required. To display the impact, please provide the applicable unit rates under the current Board-Approved Methodology, the unit rates under the Proposed Methodology, and the resulting net impacts between the cases. Please provide all assumptions relied on in calculating the impacts.

c) Please confirm whether EGI is currently considering any potential future rate design changes to M12 or C1 rate classes. If confirmed, please describe the changes being considered.

d) In Reference 3, please explain what EGI means by "manage revenue to cost ratios, maintain rate class continuity and address bill impacts.".

Response

a) Confirmed.

b) Please see Attachment 1. For the purposes of this response, Enbridge Gas prepared Rate M12/C1 Dawn-Parkway unit rates, assuming the cost allocation variances identified in Exhibit B, Tab 1, Schedule 1, Appendix C, Table 1, column (c) and column (f) were adjusted in rates.

c) Confirmed. Enbridge Gas is considering a potential change to the rate design of the Rate M12/C1 transportation demand charges to reflect the proposed cost allocation changes to Dawn Station and Parkway Station and the approved cost allocation changes to Kirkwall Station from Union's 2014 Rates proceeding (EB-2013-0365). As part of this change, the rate design for Rate M12/C1 transportation demand charges on the Dawn-Parkway system would recover the demand costs associated with Dawn Station, Kirkwall Station and Parkway Station from each of the Rate M12/C1 Dawn-Parkway transportation service options that utilize each station. For example, the recovery of Parkway Station costs would include Dawn-Parkway and Kirkwall-Parkway transportation demands and exclude the Dawn-Kirkwall transportation demands because that service does not use Parkway Station. This rate design proposal will price each of the Rate M12/C1 Dawn-Parkway transportation demand charges by path (i.e. Dawn-Parkway, Dawn-Kirkwall and Kirkwall-Parkway) and supports cost causation principles.

Enbridge Gas is in early stages of planning for rebasing and may propose additional rate design changes as part of the rebasing application.

d) "Manage revenue to cost ratios, maintain rate class continuity and address bill impacts" are examples of rate design considerations. As part of a cost of service proceeding there are several rate design considerations used to determine rate changes. While the allocated cost of service is a primary driver of setting rates, there are other considerations that impact the proposed rates. The following are a list of rate design considerations:

- The allocated cost of service;
- The level of current rates and the magnitude of the proposed change;
- The revenue deficiency/sufficiency for the company as a whole;
- The relative rate changes of other rate classes;
- The potential impact on customers;
- The level of contribution to fixed cost recovery;
- Customer expectations with respect to rate stability and predictability; and
- Equivalency of comparable service options.

ENBRIDGE GAS INC.
M12/M12-X/C1 Transportation Demand Charges Impacts of Cost Allocation Methodologies
Based on 2019 Cost Allocation Study Directive

		Demand Charge						Impact of Cost Study Proposals (Column (d))			
Line No.	Particulars ($/GJ/mth)	2019 Approved EB-2018-0305	Rate Impact of Board-Approved Methodology	Board-Approved Methodology	Rate Impact of Cost Study Proposals	Cost Study Proposals	Total Rate Impact	Panhandle / St. Clair	Parkway Station	Dawn Station	Total
		(a)	(b) = (c - a)	(c)	(d) = (e - c)	(e)	(f) = (b + d)	(g)	(h)	(i)	(j) = (g+h+i)
1	M12/C1 Dawn to Kirkwall	3.058	(0.379)	2.679	0.045	2.724	(0.334)	-	0.096	(0.051)	0.045
2	M12/C1 Dawn to Parkway	3.602	(0.424)	3.178	0.115	3.293	(0.309)	-	0.116	(0.001)	0.115
3	M12/C1 Kirkwall to Parkway	0.545	(0.046)	0.499	0.070	0.569	0.024	-	0.020	0.049	0.070
4	C1 Parkway to Dawn/Kirkwall	0.848	0.023	0.871	0.031	0.902	0.054	-	0.032	(0.001)	0.031
5	C1 Kirkwall to Dawn	1.496	0.075	1.571	0.026	1.597	0.101	-	0.056	(0.030)	0.026
6	M12-X	4.450	(0.401)	4.049	0.146	4.195	(0.255)	-	0.148	(0.002)	0.146

ENBRIDGE GAS INC.

Answer to Interrogatory from
TransCanada PipeLines Limited ("TCPL")

INTERROGATORY

Reference:

1) Exhibit B, Tab 1, Schedule 1, Appendix C, Pages 17-19 of 30.
2) Exhibit B, Tab 1, Appendix C, Working Papers, Schedule 3, Page 3 of 4.
3) Union's Response to TCPL Interrogatory Exhibit B11.4, Attachment 1, EB-2013-0365.
4) Exhibit B, Tab 1, Appendix C, Working Papers, Schedule 2, Page 6 of 7.

Preamble:

In Reference 1, EGI states that as part of the existing Board approved cost allocation methodology for Parkway Station, Dawn-Parkway demand costs are allocated to in-franchise and ex-franchise rate classes in proportion to easterly peaking distance-weighted design day demands (also referred to as "commodity-kilometres") on the Dawn-Parkway system.

In Reference 1, EGI states that Parkway Station provides a benefit to Union South in-franchise customers through obligated deliveries at Parkway on design day, which reduces the size of the Dawn-Parkway facilities required to transport gas on the Dawn-Parkway System for Union South customers. According to EGI, without the Parkway obligated deliveries, the Dawn-Parkway facilities would need to be larger and as a result, the Union South in-franchise rates would be higher.

In Reference 1, EGI states that under the proposed cost allocation methodology, it separately classified the Parkway Station demand costs into a new Parkway Station Demand functional classification. These demand costs include the plant assets and O&M expenses related to the measuring and regulating costs and compression costs at Parkway. EGI proposes to allocate the measuring and regulating costs at Parkway in proportion to the bi-directional design day demands of the Parkway Station. EGI proposes to allocate the compressor costs at Parkway in proportion to the easterly design day demands requiring compression at

Parkway.

In Reference 2, rate class impacts are provided for the proposed Parkway Station cost allocation methodology.

In Reference 3, a schedule is provided showing commodity-kilometres.

In Reference 4, revenue requirement by rate class is shown for C1 (column r) and M12 (column t) services.

Question:

a) In which proceeding was the existing Board-approved cost allocation methodology for Parkway Station first approved?

b) Regarding Reference 2), please provide a breakdown by rate class of the following costs allocated to the new Parkway Station Demand functional classification that is shown in column (b) of Schedule 3, Page 3 of 4:

   i. measuring and regulating costs;
   ii. compression costs; and
   iii. any other costs that are included in column (b).

c) Please provide a table showing the allocation units used in the Cost Allocation Study to allocate Parkway compression costs to the rate classes shown in Reference 2).

d) What percentage of Parkway Station compression costs are allocated to M12 and C1 rate classes:

   i. under the current Board-approved cost allocation methodology; and
   ii. under the proposed cost allocation methodology for Parkway Station in the Cost Allocation Study

e) What percentage of Parkway Station compression costs are allocated to Union North, Union South, Ex-Franchise and any other applicable rate classes:

   i. under the current Board-approved cost allocation methodology; and
   ii. under EGI's proposed cost allocation methodology for Parkway Station in the Cost Allocation Study

f) Please provide a schedule showing the commodity-kilometres used in the Cost Allocation Study to allocate Dawn-Parkway demand costs to in-franchise and ex-franchise rate classes in the same format as Reference 3).

g) Please explain how the commodity-kilometres in f) are adjusted to account for Parkway obligated deliveries made by in-franchise customers.

h) Please provide a schedule showing the commodity-kilometres used to allocate Dawn-Parkway demand costs to in-franchise and exfranchise rate classes in the same format as Reference 3), except assume that all in-franchise customers are served from Dawn with no regard for Parkway obligated deliveries.

i) Please provide the Parkway obligated delivery volumes by year from 2015 to 2020, and any forecast EGI may have of such volumes for future years.

j) Please provide the design day capacity reduction on the Dawn- Parkway system as a result of Parkway obligated deliveries.

k) Please provide an approximation of the reduction in utility plant rate base of the Dawn-Parkway system made possible by Parkway obligated deliveries.

l) Please quantify the impact to Union South in-franchise rates without Parkway obligated deliveries on a $/GJ basis.

m) Please confirm that Parkway obligated deliveries are provided at the discharge side of the Parkway compression facilities. If not confirmed, please explain.

n) Please confirm there are no impacts to EGD Rate Zone rate classes as a result of the Cost Allocation Study. If not confirmed, please explain.

o) Does the proposed cost allocation change to Parkway Station impact the costs allocated to volumes/services flowing through Parkway Consumers 1 and 2, Parkway EGT and/or the Lisgar custody transfer station? If so, please quantify the cost impact for the volumes/services utilized at each location, and quantify how the measuring and regulating costs, compression costs, and any other costs at Parkway Station are allocated to these volumes/services.

p) Regarding Reference 4), please detail what is included in the Total Cost of Gas and Underground Storage amounts listed for C1 and M12 services on lines 4 and 6. If applicable, please explain how these costs are differentiated between those shippers providing fuel in-kind and those who do not.

Response

a) The Board-approved cost allocation methodology for Parkway Station classifies the costs as part of the Dawn-Parkway Easterly Demand functional classification. Current Board-approved cost allocation methodology allocates Dawn-Parkway Easterly Demand costs to in-franchise and ex-franchise rate classes in proportion to easterly peaking distance-weighted design day demands (also referred to as "commodity-kilometres") on the Dawn-Parkway transmission system.

   The cost allocation methodology for Dawn-Parkway Easterly Demand costs, which includes the Parkway Station, was approved by the Board in Union's 1997 Cost of Service proceeding (EBRO 493/494). The Board most recently approved the cost allocation methodology, including Parkway Station, as part of Union's 2013 Cost of Service proceeding (EB-2011-0210).

b) Please see Attachment 1 for the rate class breakdown of proposed Parkway Station Demand costs into measuring and regulating costs, compression costs, and all other costs.

c) Please see Attachment 2, column (c).

d) Please see Attachment 2, line 18 & line 20 for the percentage of Parkway Station compression costs allocated to Rate C1 and Rate M12, respectively.

e) Please see Attachment 2, line 16, line 23, and line 29 for the percentage of Parkway Station compression costs allocated to Union South, Ex-Franchise, and Union North, respectively.

f) Please see Attachment 3.

g) Parkway Obligated Deliveries ("PDO") made by Union South in-franchise customers are delivered to Parkway. With respect to the PDO impact on the commodity-kilometre calculation, Parkway is assigned kilometre post 0. A distance from Parkway is calculated for each lateral. Starting at Parkway, a decision is made as to whether there is adequate PDO to supply the lateral's demand. If yes, the commodity-kilometre is calculated by multiplying the lateral demand by the distance from Parkway. The PDO available for the next lateral is reduced by the amount of demand served. This process continues in a westerly direction until there is no PDO remaining. All lateral demands not fully served by the PDO to the west of this point are supplied from Dawn. The total in-franchise commodity-kilometre calculation is reduced by having the PDO supply demands from Parkway.

h) Please see Attachment 4.

i) Please see Attachment 5.

j) The capacity of the Dawn-Parkway system would need to increase by 208 TJ/d as of November 2019 without the obligated deliveries at Parkway.

k) Enbridge Gas would need to invest approximately $335 million to $565 million in the expansion of the Dawn to Parkway system to increase the capacity by 208 TJ/d.

l) The impact to Union South in-franchise rate classes of the investment required to shift the obligated deliveries from Parkway to Dawn is approximately $6.10/GJ to $8.50/GJ per unit of in-franchise demand on the Dawn-Parkway system.

m) Confirmed.

n) Not confirmed. If the Board directed Enbridge Gas to implement cost allocation changes prior to rebasing as a result of the cost allocation study results, the EGD rate zone would be impacted by the change to Rate M12/C1 and Rate M16. Please see Exhibit I.SEC.8 for the estimated bill impacts for the EGD rate zone.

o) Please see Table 1.

Table 1

Impact of Parkway Station Cost Allocation Methodology Proposal
on the Rate M12 Costs

Line No.	Particulars ($000's)	Board-Approved	Proposed	Impact of Parkway Station Proposal
		(a)	(b)	(c) = (b-a)
1	Measuring and Regulating Costs	2,502	2,977	475
2	Compression Costs	14,456	17,140	2,684
3	All Other Costs	24,757	29,373	4,616
4	Total	41,715	49,490	7,775

p) Please see Attachment 6.

There is no differentiation between customers that provide fuel in kind and those that do not. Customers that provide fuel in kind provide the equivalent amount of gas as customers whose fuel requirements are provided by the utility. For the purposes of determining the revenue requirement and cost allocation, all fuel requirements are valued based on the Dawn Reference Price.

UNION RATE ZONES
Rate Class Breakdown of Parkway Station Demand Costs
Measuring & Regulating Costs, Compression Costs, and All Other Costs

Line No.	Particulars ($000's)	Measuring & Regulating Costs	Compression Costs	All Other Costs	Parkway Station Demand Costs (1)
		(a)	(b)	(c)	(d) = (a+b+c)
	Union South				
1	M1	49	-	93	143
2	M2	17	-	32	49
3	M4 - Firm	4	-	8	13
4	M4 - Interruptible	-	-	-	-
5	M5 - Firm	0	-	0	0
6	M5 - Interruptible	-	-	-	-
7	M7 - Firm	3	-	6	9
8	M7 - Interruptible	-	-	-	-
9	M9	1	-	2	3
10	M10	0	-	0	0
11	T1 - Firm	2	-	5	7
12	T1 - Interruptible	-	-	-	-
13	T2 - Firm	16	-	30	46
14	T2 - Interruptible	-	-	-	-
15	T3	5	-	10	15
16	Total Union South	98	-	185	282
	Ex-Franchise				
17	Ex. Util. Space	-	-	-	-
18	C1 - Firm	15	139	221	375
19	C1 - Int	-	-	-	-
20	M12	2,962	17,001	29,152	49,116
21	M13	-	-	-	-
22	M16	-	-	-	-
23	Total Ex-Franchise	2,977	17,140	29,373	49,490
	Union North				
24	R01	120	1,114	1,770	3,004
25	R10	37	346	550	934
26	R20	19	178	283	481
27	R100	0	5	7	12
28	R25	1	5	8	13
29	Total Union North	177	1,648	2,619	4,444
30	Total Union Rate Zones	3,252	18,788	32,176	54,217

Notes:
(1) Exhibit B, Tab 1, Appendix C, Working Papers, Schedule 3, p. 3, column (b).

UNION RATE ZONES
Rate Class Allocation of Parkway Station Compressor Costs

Line No.	Particulars ($10^6m^3/d$)	Board-approved Dawn-Parkway Easterly Allocator (2)	Board-approved %	Proposed Parkway Compression Allocator (1)	Proposed %
		(a)	(b)	(c)	(d)
	Union South				
1	M1	3,366	8.63%	-	-
2	M2	1,145	2.94%	-	-
3	M4 - Firm	299	0.77%	-	-
4	M4 - Interruptible	-	-	-	-
5	M5 - Firm	1	0.00%	-	-
6	M5 - Interruptible	-	-	-	-
7	M7 - Firm	204	0.52%	-	-
8	M7 - Interruptible	-	-	-	-
9	M9	61	0.16%	-	-
10	M10	1	0.00%	-	-
11	T1 - Firm	163	0.42%	-	-
12	T1 - Interruptible	-	-	-	-
13	T2 - Firm	1,077	2.76%	-	-
14	T2 - Interruptible	-	-	-	-
15	T3	351	0.90%	-	-
16	Total Union South	6,667	17.09%	-	-
	Ex-Franchise				
17	Ex. Util. Space	-	-	-	-
18	C1 - Firm (3)	193	0.50%	857	0.74%
19	C1 - Int	-	-	-	-
20	M12	29,823	76.45%	104,894	90.49%
21	M13	-	-	-	-
22	M16	-	-	-	-
23	Total Ex-Franchise	30,017	76.94%	105,751	91.23%
	Union North				
24	R01	1,574	4.03%	6,874	5.93%
25	R10	489	1.25%	2,138	1.84%
26	R20	252	0.65%	1,100	0.95%
27	R100	6	0.02%	28	0.02%
28	R25	7	0.02%	29	0.03%
29	Total Union North	2,328	5.97%	10,170	8.77%
30	Total Union Rate Zones	39,012	100.00%	115,921	100.00%

Notes:
(1) Exhibit B, Tab 1, Appendix C1, Schedule 5.24, Row 244.
(2) Exhibit B, Tab 1, Appendix C1, Schedule 5.24, Row 412.
(3) Related to North T-Service from Dawn customers.

UNION RATE ZONES
Dawn-Parkway Allocation Units
Winter 2019/20

Line No.	Particulars	Demand ($10^6m^3/d$) (a)	Kilometre Post (km) (b)	Commodity Kilometre (($10^6m^3/d$)*km) (c)
	Union Demands Supplied by Dawn			
1	Forest, Watford	0.354	44.01	15.569
2	Strathroy	0.246	54.93	13.486
3	Byron	2.984	73.05	217.960
4	Hensall	0.689	85.74	59.097
5	London N	2.657	90.35	240.092
6	Hensall	0.563	85.74	48.303
7	St Mary's	0.219	103.93	22.768
8	Stratford	1.390	121.45	168.811
9	Beachville	1.461	121.45	177.427
10	Oxford	1.159	142.92	165.637
11	Owen Sound Line	6.874	159.39	1,095.679
12	Cambridge	2.071	175.14	362.801
13	Brantford	2.758	175.14	483.090
14	Guelph	2.342	183.67	430.230
15	Kirkwall- Dominion	2.181	188.67	411.427
16	Gate 3	1.391	188.67	262.363
17	Gates 1 & 2	7.171	199.25	1,428.726
18	Milton	1.920	218.09	418.681
19	Milton East (dist'n)	0.224	221.61	49.563
20	HH Power Plant	2.661	221.61	589.704
21	Total Union Demands Supplied by Dawn	41.314		6,661.412
	Union Demands Supplied by Parkway			
22	HH Power Plant	0.819	7.33	6.003
23	Burlington, Oakville	4.238	0.00	0.000
24	Parkway (Greenbelt)	0.565	0.00	0.000
25	Total Union Demands Supplied by Parkway	5.621		6.003
	Union Demands Supplied by Kirkwall			
26	Gate 3	0.542	0.00	0.000
27	Total In-Franchise	47.478		6,667.415
	Storage & Transportation Contracts			
28	Dawn to Parkway	126.725	228.94	29,012.429
29	Dawn to Kirkwall	3.015	188.67	568.815
30	Kirkwall to Parkway	10.813	40.27	435.428
31	Total S & T	140.553		30,016.671
32	Northern & Eastern Areas	10.170	228.940	2,328.217
33	Total Union and S&T	198.200		39,012.303

UNION RATE ZONES
Dawn-Parkway Allocation Units
Winter 2019/20

Line No.	Particulars	Demand ($10^6m^3/d$)	Kilometre Post (km)	Commodity Kilometre (($10^6m^3/d$)*km)
		(a)	(b)	(c)
	Union Demands Supplied by Dawn			
1	Forest, Watford	0.354	44.01	15.569
2	Strathroy	0.246	54.93	13.486
3	Byron	2.984	73.05	217.960
4	Hensall	0.689	85.74	59.097
5	London N	2.657	90.35	240.092
6	Hensall	0.563	85.74	48.303
7	St Mary's	0.219	103.93	22.768
8	Stratford	1.390	121.45	168.811
9	Beachville	1.461	121.45	177.427
10	Oxford	1.159	142.92	165.637
11	Owen Sound Line	6.874	159.39	1095.679
12	Cambridge	2.071	175.14	362.801
13	Brantford	2.758	175.14	483.090
14	Guelph	2.342	183.67	430.230
15	Kirkwall- Dominion	2.181	188.67	411.427
16	Gate 3	1.391	188.67	262.363
17	Gates 1 & 2	7.171	199.25	1428.726
18	Milton	1.920	218.09	418.681
19	Milton East (dist'n)	0.224	221.61	49.563
20	HH Power Plant	3.480	221.61	771.203
21	Burlington, Oakville	4.238	228.94	970.248
22	Parkway (Greenbelt)	0.565	228.94	129.351
23	Total Union Demands Supplied by Dawn	46.936		7942.509
	Union Demands Supplied by Parkway			
24	HH Power Plant	0.000	7.33	0.000
25	Burlington, Oakville	0.000	0.00	0.000
26	Parkway (Greenbelt)	0.000	0.00	0.000
27	Total Union Demands Supplied by Parkway	0.000		0.000
	Union Demands Supplied by Kirkwall			
28	Gate 3	0.542	0.00	0.000
29	Total In-Franchise	47.478		7942.509
	Storage & Transportation Contracts			
30	Dawn to Parkway	126.725	228.94	29,012.429
31	Dawn to Kirkwall	3.015	188.67	568.815
32	Kirkwall to Parkway	10.813	40.27	435.428
33	Total S & T	140.553		30016.671
34	Northern & Eastern Areas	10.170	228.940	2328.217
35	Total Union and S&T	198.201		40287.397

UNION RATE ZONES
Actual Parkway Delivery Obligation Volumes

Line No.	Particulars (TJ/d)	Customers without M12 Service	Customers with M12 Service	TCE Halton Hills	Total
		(a)	(b)	(c)	(d)
1	November 2021 - forecast (1)	208	31	0	239
2	November 2020 - forecast (1)	208	31	0	239
3	November 2019 (1)	208	31	0	239
4	November 2018 (1)	197	31	0	228
5	November 2017 (1)	197	31	70	298
6	November 2016 (2)	254	31	84	369
7	November 2015 (2)	228	33	84	345

Notes:
(1) Exhibit B, Tab 1, Schedule 1, Appendix A.
(2) EB-2015-0116, Exhibit A, Tab 2, Attachment 1.

UNION RATE ZONES
Total Cost of Gas and Underground Storage Operating Expenses Detail
Firrm Rate C1, Interruptible Rate C1, and Rate M12

Line No.	Particulars ($000's)	Firm Rate C1	Interruptible Rate C1	Rate M12
		(a)	(b)	(c)
	Total Cost of Gas Costs			
1	Compressor Fuel - Dawn-Parkway Easterly Commodity	94	629	7,004
2	Compressor Fuel - Dawn-Parkway Westerly Commodity	153	10	50
3	Compressor Fuel - Dawn Station Commodity	327	198	2,278
4	Compressor Fuel - Panhandle Commodity	210	34	-
5	Unaccounted For Gas (UFG) - Purchase Production Other	1,658	289	4,437
6	Other Transporation - St. Clair Demand	1,287	-	-
7	Total Cost of Gas Costs (1)	3,729	1,160	13,770
	Total Underground Storage Costs			
8	Compressor Operating - Panhandle Demand	36	-	-
9	Measuring & Regulating Operating - Panhandle Demand	0	-	-
10	Measuring & Regulating Maintenance - Panhandle Demand	1	-	-
11	Compressor Operating - Dawn-Parkway Easterly Demand	7	-	1,083
12	Compressor Maintenance - Dawn-Parkway Easterly Demand	5	-	802
13	Measuring & Regulating Operating - Dawn Station Demand	0	-	63
14	Measuring & Regulating Maintenance - Dawn Station Demand	1	-	259
15	Compressor Maintenance - Panhandle Commodity	-	349	-
16	Storage Wells Operating - System Integrity	1	0	3
17	Storage Lines Operating - System Integrity	0	0	1
18	Rents Operating - System Integrity	5	1	22
19	Other Operating - System Integrity	2	0	9
20	Storage Wells Maintenance - System Integrity	3	1	13
21	Storage Lines Maintenance - System Integrity	0	0	1
22	Other Maintenance - System Integrity	1	0	2
23	Total Underground Storage Costs (2)	63	351	2,256

Notes:
(1) Exhibit B, Tab 1, Appendix C, Working Papers, Schedule 2, p. 6, line 4, cols. (r), (s), and (t).
(2) Exhibit B, Tab 1, Appendix C, Working Papers, Schedule 2, p. 6, line 4, cols. (r), (s), and (t).

ENBRIDGE GAS INC.

Answer to Interrogatory from
TransCanada PipeLines Limited ("TCPL")

INTERROGATORY

Reference:

1) Exhibit B, Tab 1, Schedule 1, Appendix C, Pages 18-19 of 30.

Preamble:

In Reference 1, EGI states that compressor equipment is used on design day to move volumes to markets east of Parkway and includes ex-franchise Rate M12/C1 and Union North in-franchise rate classes. EGI also states that there is no allocation to Union South rate classes as Parkway Station is not used to provide compression for Union South in-franchise customers on design day.

TCPL requires more information regarding the effect of Union South deliveries on compression usage at Parkway.

Question:

a) Would the requirement for, and/or utilization of, compression facilities at Parkway Station on design day be reduced if there were no Union South in-franchise customer deliveries (flowing or contracted) along the Dawn Parkway system, and the only volumes flowing were the ex-franchise Rate M12/C1 and Union North in-franchise volumes described in Reference 1)? If so, please quantify the reduction in the requirement for, and/or utilization of, compression facilities at Parkway Station. If not, please explain why not.

b) Please provide a current Winter Design Day schematic similar to that provided in the EB-2013-0074 Application, Schedule 8-2, Page 1.

c) Please provide a similar Winter Design Day schematic as in b) assuming the same discharge pressure at the Bright compressor station, but also assume no volumes flow under any Union South rate class (i.e. only flowing contracted volumes as described in a)).

d) For the scenarios in b) and c), please provide a table summarizing delivered quantities by service class and delivery location.

e) Please provide individual graphs of daily historical flows in the Parkway area, separated by meter (i.e. Lisgar, Parkway Consumers 1 and 2, EGT and the Parkway interconnect with TC Energy) from November 1, 2012 to Jan 31, 2020.

f) Please indicate the applicable Rate Zone and service class(es) for the volumes that utilize the Lisgar custody transfer station.

Response

a) No. Compression at Parkway Station would increase on design day if there were no Union South in-franchise customer deliveries. Currently, the deliveries associated with the Union South in-franchise customers is a supply delivered on the discharge side of Parkway compression thus it reduces the net flow requirements through Parkway. The elimination of these deliveries while the M12 ex-franchise, Enbridge and Union North rate zone demands remain the same, increases the flow requiring compression and thus compression requirements at Parkway.

b) Please see Attachment 1 which was originally filed as part of the 2021 Dawn Parkway Expansion Project, EB-2019-0159, Exhibit A, Tab 7, Schedule 1, page 1.

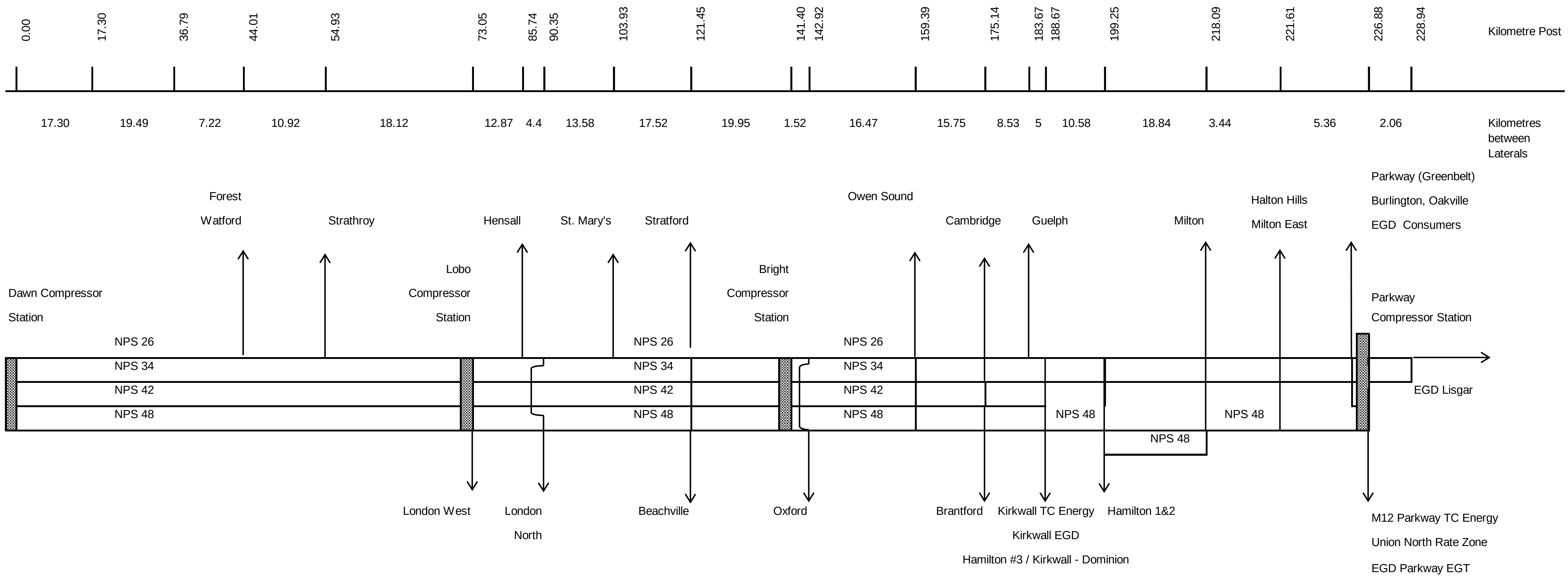
c) Please see Attachment 2.

d) The design day demands transported by the Dawn Parkway system are shown in Attachment 1 and 2 in the lower left hand side of the page.

e) Please see Attachment 3. Parkway Consumers 1, Parkway Consumers 2 and Lisgar do not flow through Parkway compression and are not included.

f) The Lisgar custody transfer station feeds a portion of the CDA delivery area in the EGD rate zone. Lisgar is served from the Dawn Parkway system by the legacy EGD rate zone Rate M12 transportation requirements.

Dawn Parkway System Demands Winter 2019/2020



Dawn Parkway System Design Day Demands

Infranchise	(GJ/d)
Union South Rate Zone	
Forest, Watford	10622
Strathroy	10175
London West	117798
Hensall	68639
London North	108672
St. Mary's	8084
Stratford	42177
Beachville	63135
Oxford	58133
Owen Sound	283633
Cambridge	83902
Brantford	154140
Kirkwall - Dominion	35296
Guelph	95454
Hamilton 3	12605
Hamilton 1&2	333696
Milton	75490
Milton East	7852
Halton Hills	135650
Parkway (Greenbelt)	26276
Burlington, Oakville	170807
Total Union South Rate Zone	1,902,235
Union North Rate Zone	438,019
EGD Rate Zone	
Kirkwall	67929
Parkway EGT	818934
Consumers 1 and 2 / Lisgar	1238085
Parkway TC Energy	935154
Total EGD Rate Zone	3,060,102
M12 Exfranchise	
Kirkwall	49,500
Parkway TC Energy	2,412,957
Total M12	2,462,457
Total Design Day Demands	7,862,813

System Capacity

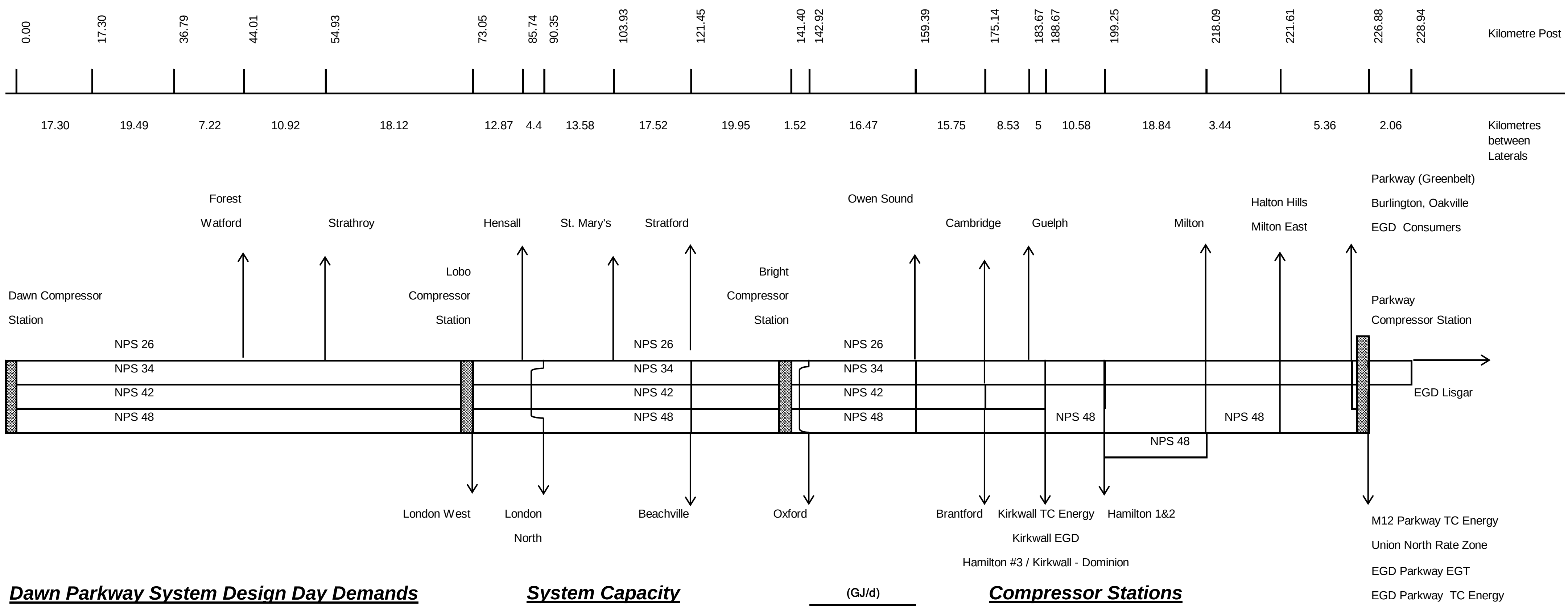
	(GJ/d)
Total System Capacity (Including Firm Service Receipts of 240,738 GJ/d)	7,878,469
Total Requirements	7,862,813
Total (Shortfall) Surplus	15,656

Compressor Stations Operating Conditions at Peak Hour

STATION	LOBO	BRIGHT	PARKWAY
Power Available (MW)	102.9	129.0	88.1
Power Required (MW)	102.9	129.0	88.0
Pressure			
Suction (kPa)	3,751	3,509	3,694
Discharge (kPa)	5,527	5,980	6,453
Compression Ratio	1.47	1.70	1.75
Flow (GJ/d)	7,265,020	7,085,069	4,409,654
Daily Fuel (GJ/d)	30,476	29,262	18,661

Winter Design Day
Dawn Parkway System
Winter 2019/2020

Dawn Parkway System Demands Winter 2019/2020



Dawn Parkway System Design Day Demands

Infranchise	
Union South Rate Zone	(GJ/d)
Forest, Watford	10622
Strathroy	10175
London West	117798
Hensall	68639
London North	108672
St. Mary's	8084
Stratford	42177
Beachville	63135
Oxford	58133
Owen Sound	283633
Cambridge	83902
Brantford	154140
Kirkwall - Dominion	35296
Guelph	95454
Hamilton 3	12605
Hamilton 1&2	333696
Milton	75490
Milton East	7852
Halton Hills	135650
Parkway (Greenbelt)	26276
Burlington, Oakville	170807
Total Union South Rate Zone	1,902,235
Union North Rate Zone	438,019
EGD Rate Zone	
Kirkwall	67929
Parkway EGT	818934
Consumers 1 and 2 / Lisgar	1238085
Parkway TC Energy	935154
Total EGD Rate Zone	3,060,102
M12 Exfranchise	
Kirkwall	49,500
Parkway TC Energy	2,412,957
Total M12	2,462,457
Total Design Day Demands	7,862,813

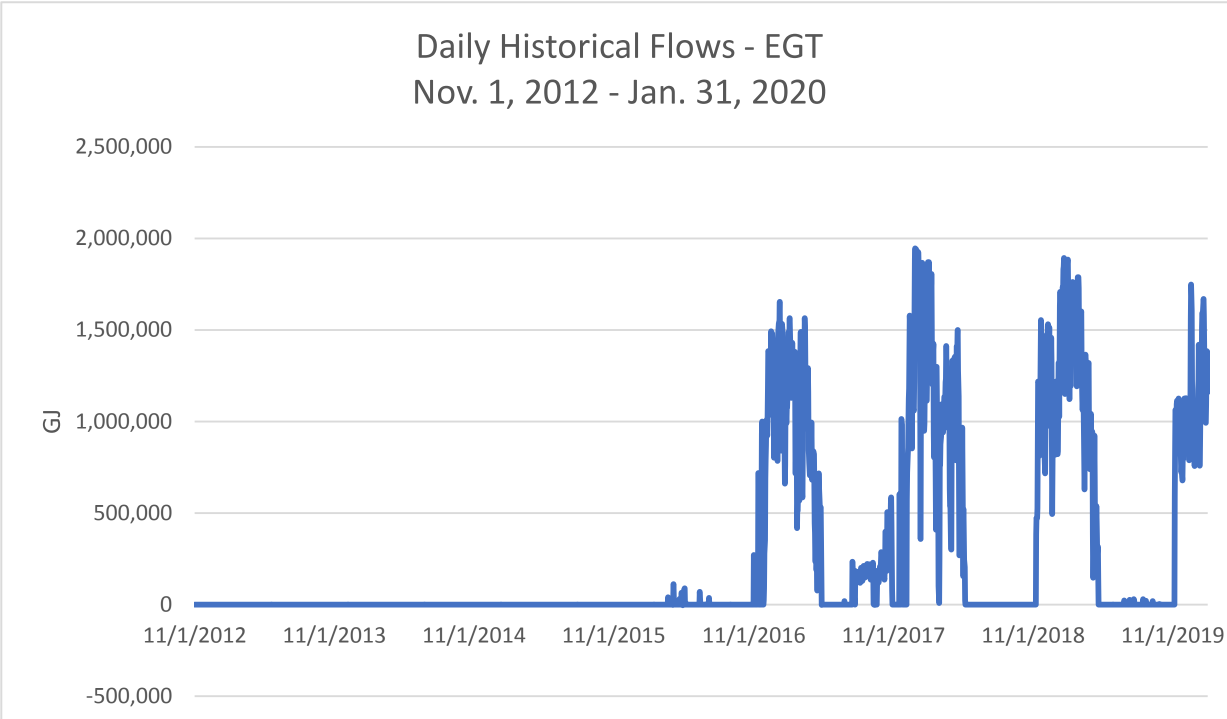
System Capacity

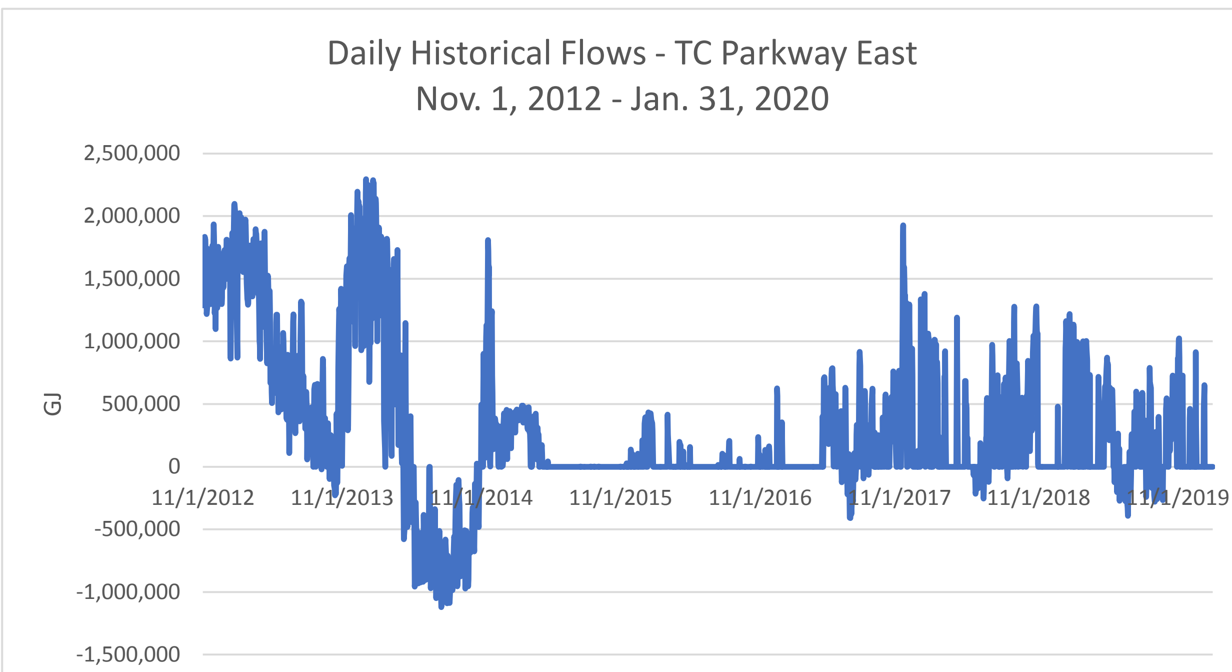
	(GJ/d)
Total System Capacity	7,638,066
(Including Firm Service Receipts of 0 GJ/d)	
Total Requirements	7,862,813
Total (Shortfall) Surplus	(224,747)

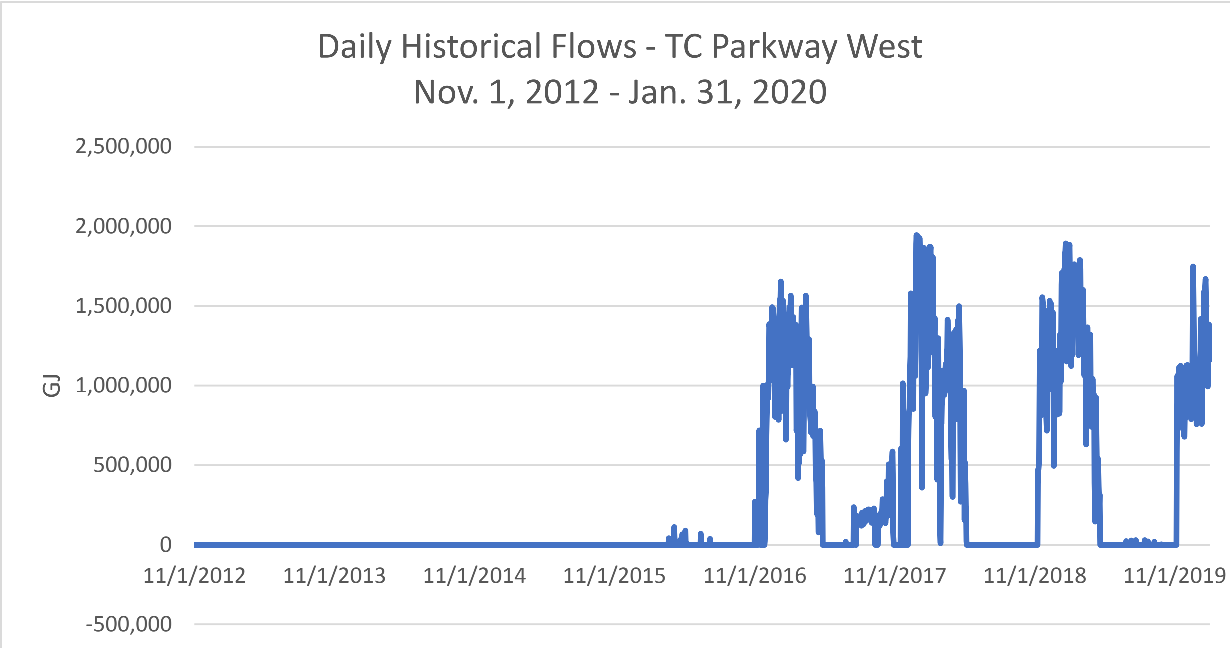
Compressor Stations Operating Conditions at Peak Hour

STATION	LOBO	BRIGHT	PARKWAY
Power Available (MW)	102.9	129.0	88.1
Power Required (MW)	102.9	129.0	88.1
Pressure			
Suction (kPa)	3,751	3,508	3,693
Discharge (kPa)	5,527	5,980	6,453
Compression Ratio	1.47	1.70	1.75
Flow (GJ/d)	7,265,129	7,084,939	4,410,001
Daily Fuel (GJ/d)	30,476	29,262	18,661

Winter Design Day
Dawn Parkway System
Winter 2019/2020


Daily Historical Flows - EGT
Nov. 1, 2012 - Jan. 31, 2020
GJ
2,500,000
2,000,000
1,500,000
1,000,000
500,000
0
-500,000
11/1/2012
11/1/2013
11/1/2014
11/1/2015
11/1/2016
11/1/2017
11/1/2018
11/1/2019


Daily Historical Flows - TC Parkway East
Nov. 1, 2012 - Jan. 31, 2020
GJ
2,500,000
2,000,000
1,500,000
1,000,000
500,000
0
-500,000
-1,000,000
-1,500,000
11/1/2012
11/1/2013
11/1/2014
11/1/2015
11/1/2016
11/1/2017
11/1/2018
11/1/2019


Daily Historical Flows - TC Parkway West
Nov. 1, 2012 - Jan. 31, 2020
GJ
2,500,000
2,000,000
1,500,000
1,000,000
500,000
0
-500,000
11/1/2012
11/1/2013
11/1/2014
11/1/2015
11/1/2016
11/1/2017
11/1/2018
11/1/2019

ENBRIDGE GAS INC.

Answer to Interrogatory from
TransCanada PipeLines Limited ("TCPL")

INTERROGATORY

Reference:

Exhibit B, Tab 1, Appendix C, Working Papers, Schedule 7.

In Reference 1), EGI provides the derivation of Rate C1 Dawn to Dawn TCPL service for 2020 proposed rates and the 2019 Cost Allocation Study. TCPL requires further information on Schedule 7.

Question:

a) Please provide an explanation for the increase in Dawn Compression Revenue Requirement (Line 1) from the $1.198 million in column (a) for 2020 Proposed to the $1.843 million in column (b) for 2019 Cost Study.

b) Please provide an explanation for the increase in Maximum Day Demand (GJ) (Line 2) from the 573,357 GJ in column (a) for 2020 Proposed to the 806,551 GJ in column (b) for the 2019 Cost Study.

c) Please provide the component amounts that make up the $548,000 on line 5 related to the Dawn Station Demand Revenue Requirement in column (a).

Response

a) The rate design of the Dawn to Dawn-TCPL demand charge includes a contribution towards the recovery of Dawn compression-related costs. The contribution is calculated using Dawn compression-related costs of the combined Ojibway (Panhandle) System and St. Clair System, adjusted for the estimated number of days compression is required (or 90 days in winter). Based on the cost study proposal to separate the Panhandle and St. Clair Systems as part of this proceeding, Enbridge Gas notes that the compression at Dawn is primarily related to the Panhandle System.

   A comparison of the 2013 and 2019 Dawn compression-related costs of the Panhandle System are provided in Table 1. The increase to operating expenses is primarily driven by an increase to the allocation of storage O&M costs to the Panhandle System, which is allocated based on compressor fuel requirements. Since the 2013 rate case, there has been a substantial increase to the Panhandle System demands served from Dawn.

Table 1
Dawn Compression-Related Costs of the Panhandle System

Line No.	Particulars ($000s)	2013	2019
1	Return on Rate Base	336	337
2	Depreciation Expense	235	239
3	Operating Expenses	621	1,254
4	Income Tax	39	14
5	Accumulated Deferred Tax Drawdown	(33)	-
6	Total Revenue Requirement	1,198	1,843

b) The maximum day demand is comprised of the Panhandle in-franchise design day demands and the maximum Bluewater and St. Clair import quantity. The maximum day demand has increased from 573,357 GJ/d to 806,551 GJ/d from 2013 to 2019 due to an increase in firm design demands on the Panhandle System. The 806,551 GJ/d also includes the ex-franchise Rate C1 and Rate M16 demands on the Panhandle and St. Clair Systems.

The calculation of the Dawn to Dawn-TCPL demand charge provided at Exhibit B, Tab 1, Appendix C, Working Papers, Schedule 7 is based on the Board-approved rate design for the Dawn to Dawn-TCPL service which includes the maximum Bluewater and St. Clair import quantity in the maximum day demand.

c) Please see Table 2.

Table 2
2013 Rate C1 Dawn to Dawn-TCPL
Dawn Station Demand Annual Revenue Requirement

Line No.	Particulars ($000s)	
1	Return on Rate Base	87
2	Depreciation Expense	460
3	Operating Expenses	-
4	Income Tax	-
5	Total Revenue Requirement (1)	548

Note:
(1) Per EB-2011-0210, Rate Order, Working Papers, Schedule 14, p.11, line 10, column (e).

ENBRIDGE GAS INC.

Answer to Interrogatory from
Vulnerable Energy Consumers Coalition ("VECC")

Interrogatory

Reference:

Exhibit B, Tab 2, Schedule 1, page 23

Question:

a) On October 15, 2019 Enbridge made a request to vary its order in EB-2018-0108 approving a leave-to-construct for the Don River Replacement Project. Has the Board approved that request?

b) Please explain what specific provisions of the Board's EB-2018-0108 Order Enbridge is seeking to vary.

Response

a) and b)

Yes, the Board has approved the Request to Vary. Please see the attachments (Attachments 1-6) to this response for correspondence between Enbridge Gas and the Board related to the Request to Vary.

Joel Denomy
Technical Manager
Regulatory Applications
Regulatory Affairs

tel 416 495 5676
EGIregulatoryproceedings@enbridge.com

Enbridge Gas Distribution
500 Consumers Road
North York, Ontario M2J 1P8
Canada

VIA EMAIL, RESS and COURIER

October 15, 2019

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
2300 Yonge Street, Suite 2700
Toronto, Ontario, M4P 1E4

Dear Ms. Walli:

Re: EB-2018-0108 – Enbridge Gas Inc. ("Enbridge Gas") – Don River Replacement Project – Request to Vary #1

Please find attached a Request to Vary Form for the Don River Replacement Project (the "Project"). The Request to Vary involves a change to the schedule for the completion of the tie-ins and thus the in-service date of the Project.

As stated in pre-filed evidence, the Project was scheduled to be placed in-service in September of 2019. This in-service date was premised on the ability to complete tie-in work during the planned shut-down of a large volume customer in 2019. Due to delays in obtaining permits the tie-in work cannot be completed during the planned shut down in 2019. The tie-in work has been rescheduled to be completed during the next planned shut down in 2020. This will push the in-service date for the Project back to May 2020.

Enbridge Gas respectfully requests a timely review and approval of this request.

Should you have any questions concerning this request please contact me at (416) 495-5676.

Yours truly,

(Original Signed)

Joel Denomy
Technical Manager, Regulatory Applications

REQUEST TO VARY

Project Name: Don River Replacement Project

OEB File Number: EB-2018-0108

Change Request: 1

Description and Rationale for Change

Enbridge Gas is unable to tie-in the new NPS 30 pipeline due to permit delays. The original tie-in date was scheduled for September 2019 in order to coincide with a maintenance shutdown of a large volume customer. As a result of the delay Enbridge Gas will be completing the tie-ins during the next planned maintenance shut-down which is scheduled for April 2020. Enbridge Gas considered an alternative option for tying in the pipeline in 2019 during the winter with the use of a bypass. However, this option was rejected by Enbridge Gas due to operational risks and network constraints that would be present during the winter heating season. Enbridge Gas is currently working with the Authorities that will be issuing the permits in order to ensure the new schedule for the Project is adhered to.

Construction and Restoration Practices

No impact to construction and/or restoration practices.

Environmental

No new environmental mitigation will be required.

Consultation

No additional consultation required.

Lands

The duration of certain permits and the duration of temporary work space will require an extension based on this change. Authorizations required for this change are set out below:

AUTHORITY	PURPOSE
City of Toronto Toronto and East York District 433 Eastern Ave, Building B, 1st Floor Toronto, Ontario M4M 1B7	Cut Permit Application for Installation of Services within the City of Toronto Streets. Follow PUCC process and contact required utilities.
City of Toronto Real Estate Services Leila Valenzuela, Project Manager Development & Portfolio Planning Metro Hall, 2nd Floor 55 John St., Toronto M5V 3C6	Temporary Work Space
Metrolinx 335 Judson Street, Toronto, Ontario M8Z 1B2 Attn: Adam Snow (adam.snow@metrolinx.com)	Rail permit.

Costs

The extension of the duration of the temporary work space requirements will increase the cost associated with the temporary work space. However, this increased cost will be covered by contingency costs for the Project. As a result, there is no impact to overall costs for the Project.

Schedule

There is an impact to the project schedule. As a result of this change the new in service date will be May 2020 rather than September 2019.

Attachments

No attachments required for this Request to Vary.

Ontario | Ontario Energy Board | Commission de l'énergie de l'Ontario

BY E-MAIL

October 24, 2019

Mr. Joel Denomy
Technical Manager, Regulatory Affairs
Enbridge Gas Inc.
500 Consumers Road
Willowdale ON M2J 1P8
Joel.Denomy@enbridge.com

Dear Mr. Denomy

Re: Enbridge Gas Inc.
Don River NPS 30 Replacement Project
Ontario Energy Board File Number EB-2018-0108
Request to Vary, Change Request No. 1

The Ontario Energy Board (OEB) is in receipt of your letter dated October 15, 2019 (Letter), in which Enbridge Gas Inc. (Enbridge Gas) proposed a change to the Don River NPS 30 Replacement Project (Project). The Project involves relocating a portion of the Don River NPS 30 pipeline (Pipeline) off of a utility bridge (Bridge) as the Bridge poses a risk to the safe operation and reliability of the pipeline. The change request involves deferring the in-service date for the Project from the planned in-service date of September 2019 to May 2020.

As part of its application, Enbridge Gas filed four engineering studies to demonstrate that structural issues with the Bridge can become further impaired if a large flood event or several small weather events were to occur, which could ultimately cause the Bridge and the Pipeline to fail. The Pipeline is a critical source of natural gas supply to a large population of firm residential, commercial, and industrial customers, as well as natural gas-fired power plants in downtown Toronto. In its application, Enbridge Gas noted that in the event of a Pipeline or a Bridge failure, Enbridge's mitigation plan would entail isolating the pipeline utilizing valves, resulting in outages that would leave a large firm customer without natural gas service. Enbridge Gas indicated that the planned in-service date for the Project was September 2019.

In its Decision and Order, the OEB found that the Project is needed to ensure the safe operation and reliability of the Don Valley Pipeline[1].

[1] EB-2018-0108, Decision and Order, issued November 29, 2018

In the Letter, Enbridge Gas states that the original in-service date was premised on its ability to complete tie-in work during the planned shut-down of a large volume customer in 2019. Due to delays in obtaining permits, the tie-in work cannot be completed during the planned shut down in 2019. The tie-in work has been rescheduled to be completed during the next planned shut down in 2020, thereby delaying the in-service date for the Project to May 2020.

In the Letter, Enbridge Gas states that it considered an alternative option for tying in the pipeline in the winter of 2019 with the use of a bypass. However, this option was rejected by Enbridge Gas due to operational risks and network constraints that would be present during the winter heating season.

Enbridge Gas noted that as a result of this change, the duration of certain permits and the duration of temporary work space will require an extension. Authorizations required for this change involve road cut permits and temporary workspace from the City of Toronto, and a rail permit from Metrolinx. Enbridge Gas states that the time extension (and in particular the extended duration of temporary work space requirements) will increase costs, but that this increased cost will be covered by the budgeted contingency for the Project. As a result, Enbridge Gas expects there will be no impact to the overall costs for the Project.

Enbridge Gas submits that the change will not modify the project's originally proposed construction or restoration methods, environmental mitigation measures, stakeholder consultations, or land requirements.

As the Manager, Applications Supply and Infrastructure, I have been delegated, under section 6 of the *Ontario Energy Board Act, 1998*, the authority of the OEB to determine whether Enbridge Gas' proposal will result in material changes to the Project in respect of which leave to construct was granted by the OEB in the EB-2018-0108 proceeding. I have been further granted the authority to approve any changes that I have concluded are not material.

Based on my review of the initial information provided, I am unable to determine whether the change proposed by Enbridge Gas is material. Enbridge Gas is asked to file the following additional information:

1. An explanation of the operational risks, network constraints, and costs associated with performing the by-pass option.
2. An explanation of how Enbridge Gas will mitigate the risks of using the utility Bridge for an additional 8 months, including how Enbridge Gas will reduce the impact of any outages for customers should the Bridge fail.

3. A comparison of the risks associated with performing the by-pass option versus the risks associated with prolonged use of the utility Bridge, including quantitative analysis.
4. A schedule for the by-pass option.

Yours truly,

Original Signed by

Nancy Marconi
Manager, Applications Supply and Infrastructure

ENBRIDGE

Asha Patel
Technical Manager
Regulatory Applications
Regulatory Affairs

tel 416 495 5642
egiregulatoryproceedings@enbridge.com

Enbridge Gas Inc.
500 Consumers Road
North York, Ontario M2J 1P8
Canada

VIA EMAIL, RESS and COURIER

November 1, 2019

Board Secretary
Ontario Energy Board
2300 Yonge Street, Suite 2700
Toronto, Ontario, M4P 1E4

Dear Board Secretary:

Re: EB-2018-0108 – Enbridge Gas Inc. ("Enbridge Gas")
Don River Replacement Project
Response to Ontario Energy Board ("the Board") Questions on Request to Vary No. 1

On October 15, 2019, Enbridge Gas submitted a Request to Vary Form for the Don River Replacement Project ("the Project"). The Request to Vary involved a change to the schedule for the completion of the tie-ins and therefore the in-service date of the project.

Subsequently on October 24, 2019 Enbridge Gas received a letter from the Board requesting additional information such that a decision can be made on Enbridge Gas's Request to Vary. Enbridge Gas's responses to the Board's questions are below.

1. *An explanation of the operational risks, network constraints, and costs associated with performing the by-pass option*

   Enbridge Gas evaluated the operational risks and network constraints associated with constructing a bypass during the winter months in order to attempt to complete the pipeline tie-ins in 2019. The primary risks include: challenges with inserting and obtaining a gas stop due to high flow conditions, potential damage to the bypass due to limited work space, potential third-party damage due to additional fittings being added to the NPS 30 main, potential for resource constraints around the holiday season and the potential for significant customer loss during the heating season should an outage occur on the line while the bypass option is being executed.

   Consideration and planning for the construction of the bypass was always within the project scope as an alternative tie-in method, if the planned maintenance shut-down timing could not be met in the original project schedule. The bypass option does not result in significant incremental costs to the overall project. The additional costs would be covered by the project contingency.

2. *An explanation of how Enbridge Gas will mitigate the risks of using the Utility Bridge for an additional 8 months, including how Enbridge Gas will reduce the impact of any outages for customers should the Bridge fail*

   Enbridge Gas will not be using the Utility Bridge for an additional eight months. Enbridge was delayed in starting construction of the new NPS 30 pipeline due to permitting delays. In the original plan there were two options to tie-in the pipe: (1) to tie-in during the planned maintenance shut-down of a large volume customer, and (2) to use a bypass if the planned maintenance option was missed in Fall 2019. The permit delays have affected the entire project schedule including the timing of when the pipeline can be tied in. As a result, the earliest that the tie-ins could occur, if the bypass option is utilized, would be December 2019 with completion in Q1 2020. This option was evaluated and eliminated for the reasons discussed above which included consideration to reduce the risk of any customer outages. Therefore, the existing NPS 30 pipeline on the Utility Bridge will be in-service for up to an additional three months. Using the Utility Bridge for up to an additional three months does not outweigh the operational risks and network constraints associated with the bypass option as discussed above.

   It is important to note that this Request to Vary does not impact the timing of the Utility Bridge removal which is still planned to commence in December 2021.

3. *A comparison of the risks associated with performing the by-pass option versus the risks associated with prolonged use of the Utility Bridge, including quantitative analysis*

   As explained above, the tie-in during the large volume customer's planned maintenance shut down in April 2020 will result in the Utility Bridge being used for up to an additional three months. Due to the risks associated with the bypass option as discussed above, the bypass option is not preferred.

4. *A schedule for the by-pass option*

   Due to the permitting delays, the bypass option would be executed starting mid-December 2019 with completion in Q1 2020.

Please contact me if you have any questions.

Yours truly,

(Original Signed)

Asha Patel
Technical Manager Regulatory Applications

Ontario Energy Board | Commission de l'énergie de l'Ontario

BY E-MAIL

November 20, 2019

Ms. Asha Patel
Technical Manager
Regulatory Applications
Enbridge Gas Inc.
500 Consumers Road
Willowdale ON M2J 1P8
EGIRegulatoryProceedings@enbridge.com

Dear Ms. Patel:

Re: Enbridge Gas Inc.
Request to Vary Don River NPS 30 Replacement Project
Ontario Energy Board File Number EB-2019-0275
Request to Vary, Change Request No. 1

On October 15, 2019, Enbridge Gas Inc. (Enbridge Gas) submitted a letter to the OEB in which it proposed a change to the Don River NPS 30 Replacement Project (Project), which had been approved by the OEB on November 29, 2018[1]. The Project involves relocating a portion of the Don River NPS 30 pipeline (Pipeline) off a utility bridge (Bridge) as the Bridge poses a risk to the safe operation and reliability of the Pipeline. The change request involves deferring the in-service date for the Project from the planned in-service date of September 2019 to May 2020.

In its October 15, 2019 letter, Enbridge Gas explained that, as a result of permit delays, it is unable to complete the final tie-in of the Pipeline until the next planned maintenance shut-down of a large volume customer, which is scheduled for April 2020. Enbridge Gas stated that it considered an alternative option for tying in the pipeline in the winter of 2019 with the use of a bypass. However, this option was rejected by Enbridge Gas due to operational risks and network constraints that would be present during the winter heating season.

The proposed change will result in an extension to the duration of certain permits and the duration of temporary workspace. Authorizations required for this change involve road cut permits and temporary workspace from the City of Toronto, and a rail permit from Metrolinx. Enbridge Gas states that the time extension (and in particular the extended duration of temporary work space requirements) will increase costs, but that this increased cost will be covered by the budgeted contingency for the Project. As a result, Enbridge

[1] EB-2018-0108

Gas expects there will be no impact to the overall costs for the Project. Enbridge Gas submitted that the change will not modify the Project's originally proposed construction or restoration practices, environmental mitigation measures, stakeholder consultations, or land requirements.

On October 24, 2019, the OEB issued a letter to Enbridge Gas requesting additional information such that a decision could be made on Enbridge Gas's proposed change. In particular, the OEB asked for:

1. An explanation of the operational risks, network constraints, and costs associated with performing the by-pass option
2. An explanation of how Enbridge Gas will mitigate the risks of using the Utility Bridge for an additional eight months, including how Enbridge Gas will reduce the impact of any outages for customers should the Bridge fail
3. A comparison of the risks associated with performing the by-pass option versus the risks associated with prolonged use of the Utility Bridge, including quantitative analysis
4. A schedule for the by-pass option

On November 1, 2019, Enbridge Gas submitted its responses to the OEB's request for more information.

Enbridge Gas stated that the operational risks and network constraints associated with constructing a bypass during the winter months include:

a) Challenges with inserting and obtaining a gas stop due to high flow conditions
b) Potential damage to the bypass due to limited work space
c) Potential third-party damage due to additional fittings being added to the NPS 30 main
d) Potential for resource constraints around the holiday season
e) Potential for significant customer loss during the heating season should an outage occur on the line while the bypass option is being executed

For these reasons, Enbridge Gas eliminated the bypass option.

In the original plan, there were two options to tie-in the pipe: (1) to tie-in during the planned maintenance shutdown of a large volume customer, and (2) to use a bypass if the planned maintenance option was missed in Fall 2019. As a result of the permitting delays, the earliest that the tie-in could occur if the bypass option is utilized would be December 2019, with completion in Q1 2020.

Enbridge Gas explained that, in its view, it will only be using the Bridge for an additional three months, rather than eight months, with the deferred tie-in option as Enbridge Gas was delayed in starting construction of the Pipeline due to permitting delays. In Enbridge

Gas' view, using the Bridge for up to an additional three months does not outweigh the operational risks and network constraints associated with the bypass option outlined above.

In its letter of November 1, 2019, Enbridge Gas did not provide information on how it would mitigate the risks of using the Bridge for an extended period of time, nor did it provide a quantitative risk analysis of the deferred tie-in relative to the winter bypass option.

The information provided to date by Enbridge Gas is insufficient to allow the OEB to determine whether the proposed deferral of the tie-in to April 2020 poses less risk than the winter bypass option.

The OEB requires Enbridge Gas, by no later than November 28, 2019, to submit to the OEB complete answers to the questions set out in the OEB's letter of October 24, 2019. Enbridge Gas should include with its response any internal and third party analysis and reports that support the conclusion that using the Bridge for an extended period of time does not outweigh the operational risks and network constraints associated with the bypass option. The information should also identify, where applicable, seasonal timing constraints around the viability of the bypass option. Enbridge Gas should also include in its response any schematics or photos that the OEB may find useful in understanding the materials, equipment and construction techniques required for both the tie-in and bypass options.

Yours truly,

Original Signed By

Christine E. Long
Board Secretary and Registrar

c: Mr. Guri Pannu, Guri.Pannu@enbridge.com

ENBRIDGE

Joel Denomy
Technical Manager,
Regulatory Applications
Regulatory Affairs

tel 416-495-5676
EGIRegulatoryProceedings@enbridge.com

Enbridge Gas Inc.
500 Consumers Road
North York, Ontario M2J 1P8
Canada

November 28, 2019

VIA EMAIL, RESS and COURIER

Christine Long
Registrar & Board Secretary
Ontario Energy Board
2300 Yonge Street, Suite 2700
Toronto, Ontario, M4P 1E4

Dear Ms. Long:

Re: EB-2018-0108 Enbridge Gas Inc. (Enbridge Gas) Don River Replacement Project (Project) Response to Ontario Energy Board (Board) Questions on Request to Vary No. 1

On October 15, 2019 Enbridge Gas submitted a Request to Vary Form for the Project. The request to vary involved a change to the schedule for the completion of the tie-ins and therefore the in-service date of the Project.

Subsequently on October 24, 2019 Enbridge Gas received a letter from the Board requesting additional information such that a decision can be made on Enbridge Gas' Request to Vary. On November 1, 2019 Enbridge Gas filed the additional information requested by the Board. On November 20, 2019 Enbridge Gas received a letter from the Board indicating that the Board required Enbridge Gas to submit complete answers to the questions set out in the Board's letter of October 24, 2019.

Enbridge Gas' updated responses to the Board's questions are set out below. For completeness the responses provided by Enbridge Gas in its November 1, 2019 letter are included. Each of these responses is followed by additional narrative which addresses the Board's request in its November 20, 2019 letter.

1. *An explanation of the operational risks, network constraints, and costs associated with performing the by-pass option*

   Enbridge Gas evaluated the operational risks and network constraints associated with constructing a bypass during the winter months in order to attempt to complete the pipeline tie-ins in 2019. The primary risks include: challenges with inserting and obtaining a gas stop due to high flow conditions, potential damage to the bypass due to limited work space, potential third-party damage due to additional fittings being added to the NPS 30 main, potential for resource constraints around the holiday season and the potential for significant customer loss during the heating season should an outage occur on the line while the bypass option is being executed.

   Consideration and planning for the construction of the bypass was always within the project scope as an alternative tie-in method, if the planned maintenance shut-down timing could not be met in the original project schedule. The bypass option does not result in significant incremental costs to the overall project. The additional costs would be covered by the project contingency.

Additional Narrative:

Operational risks, network constraints and costs associated with performing the by-pass option are more fully discussed in the points that follow. The cost of the tie-ins is approximately $1.0 million. The cost of performing the by-pass option is approximately $1.9 million. Therefore the incremental cost associated with the by-pass option is approximately $0.9 million.

a) *Operational Risk - Challenges with inserting and obtaining a gas stop due to high flow conditions.*

   Enbridge Gas reached out to T.D. Williamson, an industry expert, to understand the flow rate limitations for the equipment utilized for a by-pass. The recommendation from this industry expert was that Enbridge Gas not complete a by-pass at a flow rate of over 9.0m/s. T.D. Williamson indicated that performing a by-pass at a flow rate higher than 9.0m/s would require that the equipment used to perform the by-pass (stopple equipment) be operated outside of safe operating limits. During the time the by-pass option would be completed (i.e. December and January) Enbridge Gas network analysis estimates that the flow rate would be 13.5m/s on the Don River Pipeline.

   T.D. Williamson indicated the flow rate limitation of the stopple equipment is due to the manner in which the plugging heads are set into and retracted out of the pipeline when performing a by-pass. The plugging heads are lowered into the pipeline on a cantilever beam. Higher flow rates have more force and thus have the potential to rip off the plugging heads. This can result in the plugging heads not creating a proper seal to stop gas flow and can also potentially damage the equipment that installs the plugging heads. Figure 1 shows a typical stopple fitting and corresponding equipment. The by-pass option requires four of these fittings and equipment to be installed (two on the east side of the Don River and two on the west side of the Don River).

   Based on the expected flow conditions of the Don River Pipeline during the time that the by-pass would occur, Enbridge Gas was concerned with the risk of not obtaining a gas stop due to high flow and/or damaging the equipment used to perform the by-passes. In the event that a gas stop was unsuccessful at either of the by-passes and there was an uncontrolled release of gas, the Don River Pipeline would have to be isolated resulting in the loss of customers.

b) *Operational Risk - Potential damage to the bypass due to limited work space.*

   Figures 2 and 3 provide the proposed bypass drawings for the east and west side of the Don River respectively.

   Enbridge Gas was concerned that the limited size of the work space in which the by-passes would be performed would increase the risk of damage to the by-passes once completed. This risk arises because the by-passes would be energized and flowing gas at the same time the tie-ins are constructed. The limited working space is a result of completing this work in a highly congested area. The equipment required for the by-pass option is large, resulting in the need for adequate clearances in order to operate safely. The size of the equipment adds to the congestion on site as a result of a limited working space. Figures 4 and 5 show a typical working area and an example of a crane that would be used for the by-pass option, in addition to the regular required construction equipment. Note: The working area shown in Figure 4 is substantially larger and provides more clearance for machinery and equipment than the working space where the by-passes would be utilized for the Project.

If there was damage to either of the by-passes, depending of the extent of the damage Enbridge Gas would need to isolate the Don River Pipeline which would result in the loss of customers. The by-pass(es) would then have to be reconstructed prior to the tie-in(s) being completed.

c) *Operational Risk - Potential third-party damage due to additional fittings being added to the NPS 30 main.*

Adding the stopple fittings to the main is required for the bypass option. It reduces the depth of cover of the main by approximately 30cm. Due to the reduced depth of cover the potential for a future third party damage is higher as the main is no longer at the standard depth of cover (approximately 1.0m).

If a third party damage were to occur to any of the stopple fittings, depending on the extent of the damage, Enbridge Gas would need to isolate the Don River Pipeline which would result in the loss of customers.

d) *Operational Risk - Potential for resource constraints around the holiday season.*

With the by-pass option Enbridge Gas would be required to add an additional emergency crew on stand-by for the duration of the tie-in work. The additional cost of this crew is included in the cost of the by-pass option identified above.

e) *Network Constraint - Potential for significant customer loss during heating season should an outage occur on the line while the bypass option is being executed.*

Please see the response to Question 3 for a discussion of expected customer losses related to a bridge failure and a by-pass failure or damage.

2. *An explanation of how Enbridge Gas will mitigate the risks of using the Utility Bridge for an additional 8 months, including how Enbridge Gas will reduce the impact of any outages for customers should the Bridge fail*

Enbridge Gas will not be using the Utility Bridge for an additional eight months. Enbridge was delayed in starting construction of the new NPS 30 pipeline due to permitting delays. In the original plan there were two options to tie-in the pipe: (1) to tie-in during the planned maintenance shut-down of a large volume customer, and (2) to use a bypass if the planned maintenance option was missed in Fall 2019. The permit delays have affected the entire project schedule including the timing of when the pipeline can be tied in. As a result, the earliest that the tie-ins could occur, if the bypass option is utilized, would be December 2019 with completion in Q1 2020. This option was evaluated and eliminated for the reasons discussed above which included consideration to reduce the risk of any customer outages. Therefore, the existing NPS 30 pipeline on the Utility Bridge will be in-service for up to an additional three months. Using the Utility Bridge for up to an additional three months does not outweigh the operational risks and network constraints associated with the bypass option as discussed above.

It is important to note that this Request to Vary does not impact the timing of the Utility Bridge removal which is still planned to commence in December 2021.

<u>Additional Narrative:</u>

Enbridge Gas' mitigation measures for continuing to use the utility bridge are set out in Exhibit B, Tab 1, Schedule 1, Page 6. As discussed in that narrative, Enbridge Gas executed a bridge abutment remediation plan which used Articulated Concrete Block mats to mitigate against further erosion of the river bank around the abutment. This work was completed in September of 2017 and reduced the probability of bridge failure in 5 years from 4.90% to 2.47%. This equates to a 50% reduction in the probability of bridge failure in 5 years. The probability of failure calculations are set out at Exhibit B, Tab 1, Schedule 1, Page 5, Table 4. The bridge abutment remediation plan is the short term solution to mitigating the risks associated with continuing to use the utility bridge and allows Enbridge Gas a few years to complete the long term solution of removing the Don River Pipeline from the utility bridge.

In the event that the bridge fails Enbridge Gas has developed a contingency plan to isolate the Don River Pipeline crossing. This contingency plan includes closing valves to isolate the pipeline should an emergency occur. This will result in customer losses. Enbridge Gas also monitors weather and water levels during periods of high rainfall.

3. *A comparison of the risks associated with performing the by-pass option versus the risks associated with prolonged use of the Utility Bridge, including quantitative analysis*

As explained above, the tie-in during the large volume customer's planned maintenance shut down in April 2020 will result in the Utility Bridge being used for up to an additional three months. Due to the risks associated with the bypass option as discussed above, the bypass option is not preferred.

Additional Narrative:

Enbridge Gas has developed an estimate of the cost associated with two risk scenarios: a bridge failure and a by-pass failure. The by-pass failure scenario assumes that the Don River Pipeline would have to be isolated should any of the risks identified in the response to Question 1 (i.e. Operational Risks a), b) and c)) materialize. These estimates include assumptions related to expected customer losses, costs to make safe, re-light, etc. Table 1 summarizes the expected probability and cost associated with each scenario.

The risk of a bridge failure and therefore a pipe failure is 2.47%. A bridge failure would most likely occur during the late spring or early summer when water levels are high and the Don River could have debris. Enbridge Gas would note that the tie-ins will occur prior to the timeframe that significant flooding is most likely to occur. The impact of this event is described at Exhibit B, Tab 1, Schedule 1 , Page 18. A bridge failure would result in the loss of approximately 51,000 customers, including Portlands Energy Centre (PEC).

Enbridge Gas does not have readily available information on the likelihood of a by-pass failure. However, based on the information provided by T.D. Williamson, Enbridge Gas believes that operating the stopple equipment outside of safe operating limits would significantly increase the probability of a by-pass failure. A by-pass failure would occur in December and/or January. In this event the Don River Pipeline would be isolated, also resulting in a loss of customers. The impact of this event would be similar to the impact of a bridge failure in the middle of winter. This outcome is described at Exhibit B, Tab 1, Schedule 1, Page 17. Under design conditions this event would result in the loss of approximately 92,500 customers, including PEC.

Table 1: Risk Analysis

Option	Risk	Timing of Risk	Customer Losses	Cost ($ Millions)
(a)	(b)	(c)	(d)	(e)
Delay Tie-in	Bridge Failure in 5 Years	Spring	51,000	$19.1
Perform By-Pass	By-Pass Failure	Winter	92,500	$36.2

Should the Don Valley Pipeline have to be isolated, delaying the tie-ins results in the least amount of customer losses and requires the least cost to recover the customers lost. Based on this analysis delaying the tie-ins is the least risky option.

4. *A schedule for the by-pass option*

Due to the permitting delays, the bypass option would be executed starting in December 2019 with completion in Q1 2020.

Please contact me if you have any questions.

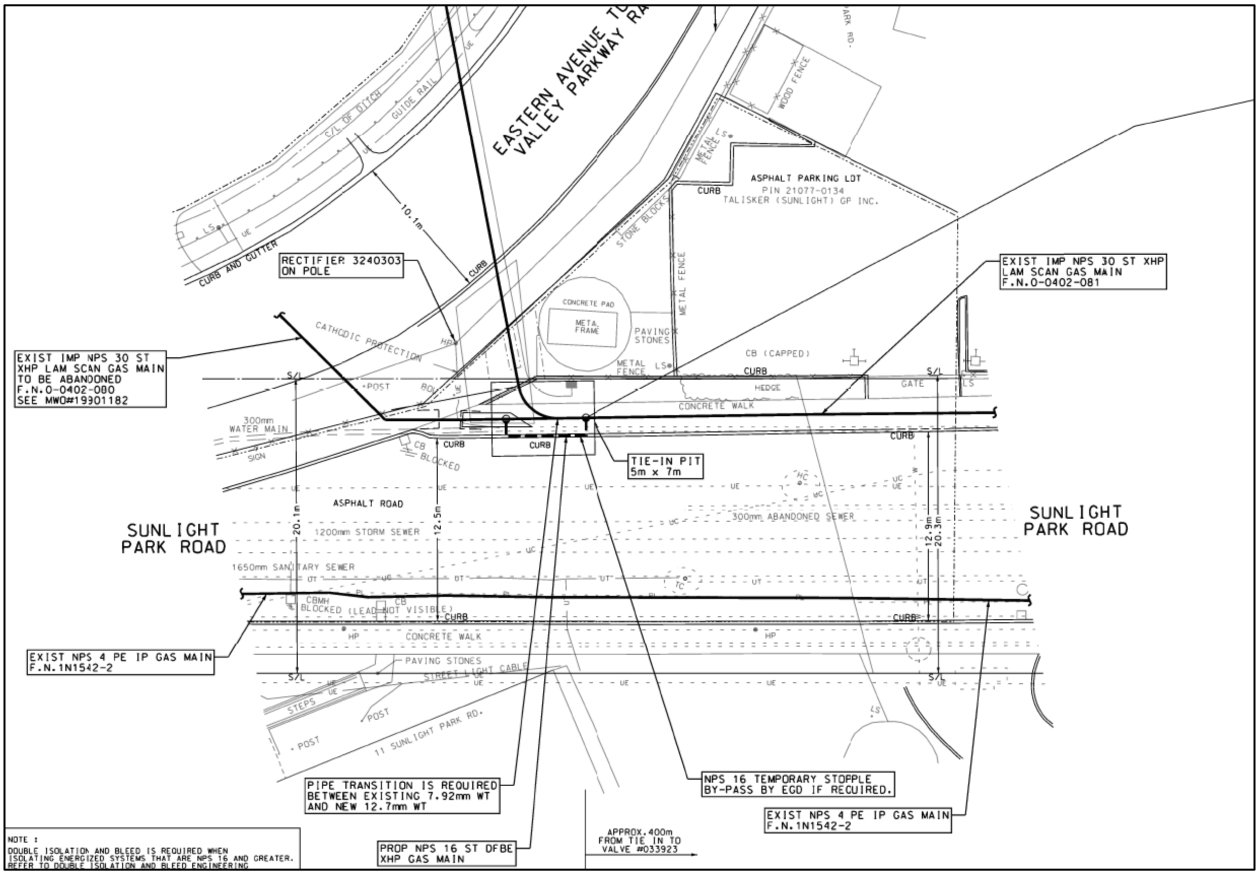
Yours truly,

(Original Signed)

Joel Denomy
Technical Manager Regulatory Applications

Figure 1: Stopple Fitting

Figure 2: By-Pass Drawing – East Side of Don River



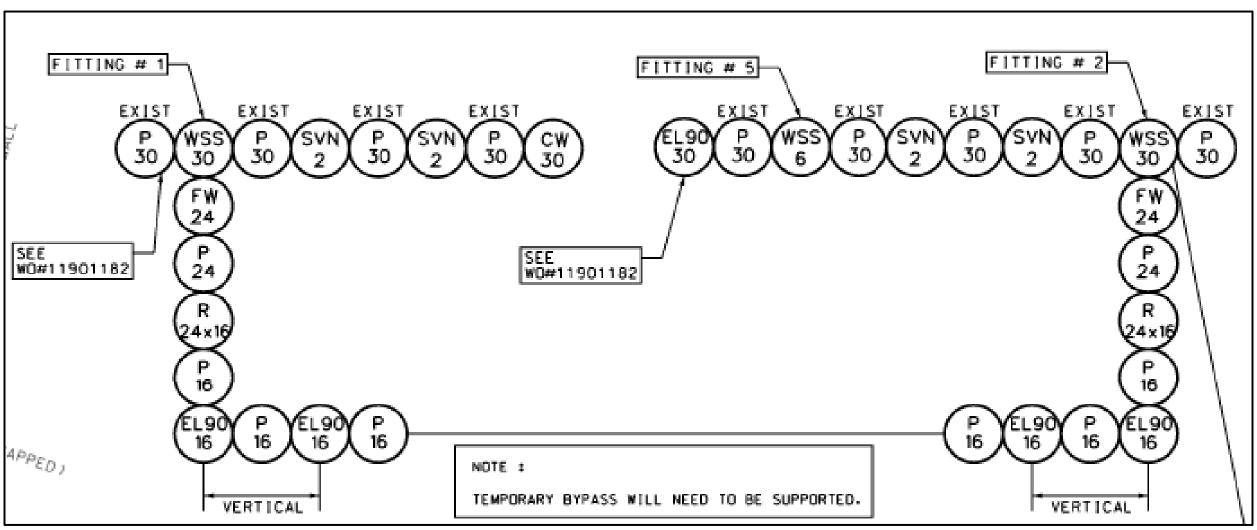


Figure 3: By-Pass Drawing – West Side of Don River

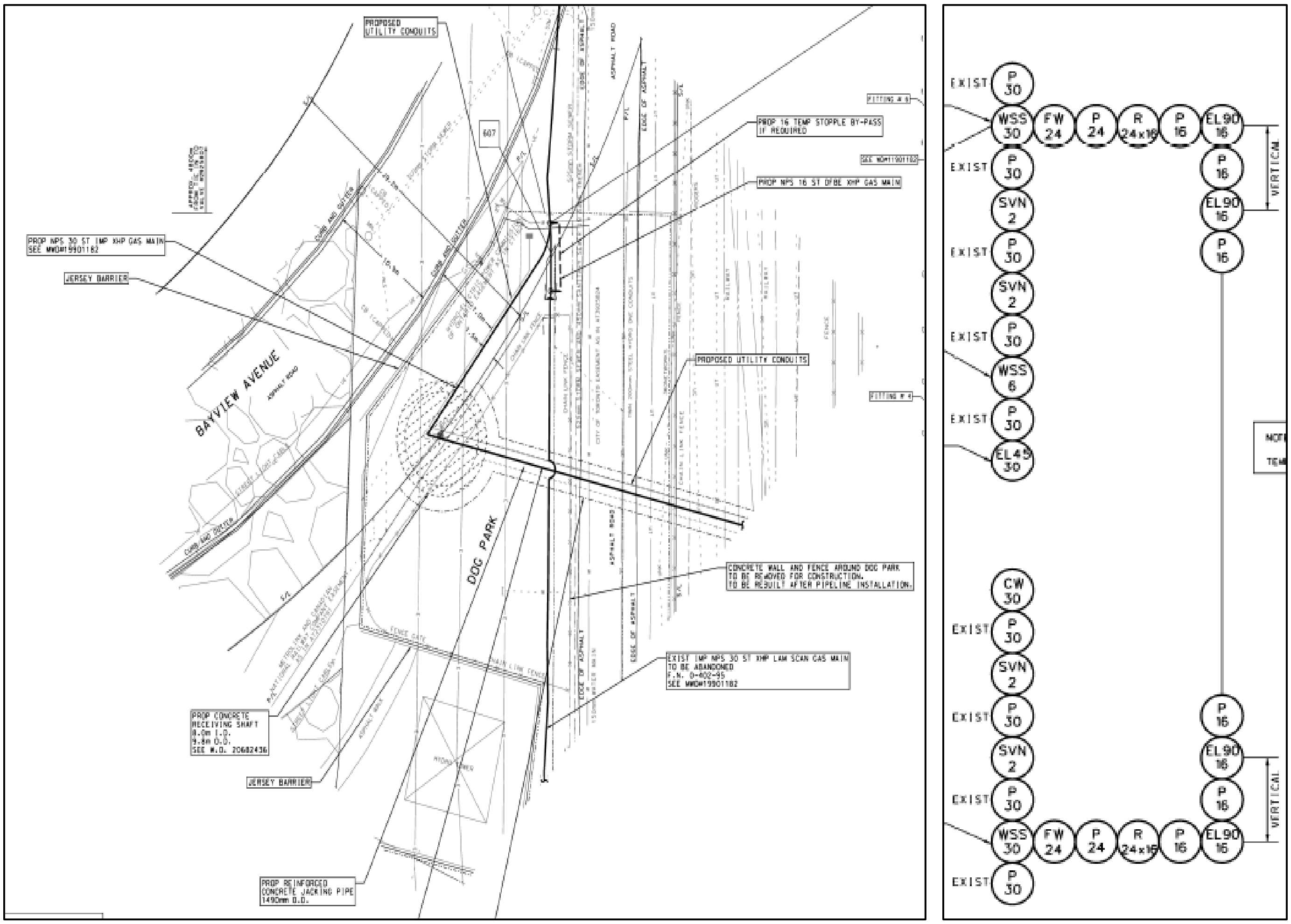


Figure 4: Typical Working Area and Stopple Fitting on Parkway North NPS 36

Figure 5: Typical Crane for Moving Fittings

Ontario Energy Board | Commission de l'énergie de l'Ontario

Ontario

BY E-MAIL

December 5, 2019

Mr. Joel Denomy
Technical Manager, Regulatory Affairs
Enbridge Gas Inc.
500 Consumers Road
Willowdale ON M2J 1P8
Joel.Denomy@enbridge.com

Dear Mr. Denomy:

Re: Enbridge Gas Inc.
Request to Vary Don River NPS 30 Replacement Project
Ontario Energy Board File Number EB-2019-0275
Request to Vary

On October 15, 2019, Enbridge Gas Inc. (Enbridge Gas) submitted a letter to the OEB in which it requested a variance to the OEB decision and order (Decision)[1] approving the Don River NPS 30 Replacement Project (Project). The Project involves relocating a portion of the Don River NPS 30 pipeline (Pipeline) off a utility bridge (Bridge) that poses a risk to the safe operation and reliability of the Pipeline. The requested variance involves deferring the in-service date for the Project from the planned in-service date of September 2019 to May 2020.

In its October 15, 2019 letter, Enbridge Gas explained that, as a result of certain permit delays, it is unable to complete the final tie-in of the Pipeline until the next planned maintenance shut-down of a large volume customer, which is scheduled for April 2020. Enbridge Gas stated that it had considered an alternative option for tying in the Pipeline in the winter of 2019 with the use of a bypass. However, Enbridge Gas rejected this option due to operational risks and network constraints that would be present during the winter heating season.

The proposed variance will result in an extension to the duration of certain permits and the duration of temporary workspace, namely road cut permits and temporary workspace authorizations from the City of Toronto, as well as a rail permit from Metrolinx. Enbridge Gas stated that the time extension (and in particular the extended duration of temporary work space requirements) will increase Project costs, but that this increased cost will be

[1] EB-2018-0108, Decision and Order, issued November 29, 2018

covered by the budgeted contingency for the Project. As a result, Enbridge Gas expects there will be no impact to the overall costs for the Project. Enbridge Gas submitted that the variance would not modify the Project's originally proposed construction or restoration practices, environmental mitigation measures, stakeholder consultations, or land requirements.

On October 24, 2019, the OEB issued a letter to Enbridge Gas requesting additional information in order to determine the materiality of Enbridge Gas's proposed variance. In particular, the OEB asked for:

1. An explanation of the operational risks, network constraints, and costs associated with performing the bypass option;
2. An explanation of how Enbridge Gas will mitigate the risks of using the Bridge for an additional eight months, including how Enbridge Gas will reduce the impact of any outages for customers should the Bridge fail;
3. A comparison of the risks associated with performing the bypass option versus the risks associated with prolonged use of the Bridge, including quantitative analysis;
4. A schedule for the bypass option.

On November 1, 2019, Enbridge Gas submitted its responses to the OEB's request for additional information. On November 20, 2019 the OEB issued a letter to Enbridge Gas stating that the information it had provided to date was insufficient to allow the OEB to determine whether the proposed deferral of the tie-in to April 2020 poses less risk than the winter bypass option. In particular, the OEB indicated that Enbridge Gas had not provided information on how it would mitigate the risks of using the Bridge for an extended period of time, nor did it provide a quantitative risk analysis of the deferred tie-in relative to the winter bypass option.

Enbridge Gas responded on November 28, 2019 restating the responses in its November 1, 2019 letter and providing additional commentary on the operational risks and network constraints associated with constructing a bypass during the winter months, which is summarized as follows:

a) *Challenges with inserting and obtaining a gas stop due to high flow conditions*. Enbridge Gas requested the opinion of T.D. Williamson, an industry expert, to understand the flow rate limitations for the equipment utilized for a bypass. The recommendation received was that Enbridge Gas should not complete a bypass at a flow rate of over 9.0m/s. Enbridge Gas' network analysis estimated that the flow rate would be 13.5m/s, which raised concerns about the risk of not being able to stop the flow of gas in the Pipeline due to high flow and/or of damaging the equipment used to perform the bypasses.

b) *Potential damage to the bypass due to limited work space*. Enbridge Gas stated that, if it pursued the bypass option, there would be a limited area of work space in which the bypasses would be performed and this would increase the risk of damage to the bypasses. This risk would arise because the bypasses would be energized and flowing gas at the same time the tie-ins are being constructed. The limited working space is a result of completing this work in a highly congested area. If there was damage to either of the bypasses and, depending of the extent of the damage, Enbridge Gas would need to isolate the Pipeline which would result in the loss of gas service to customers.

c) *Potential third-party damage due to additional fittings being added to the Pipeline*. Enbridge Gas stated that, executing the bypass option would require adding stopple fittings to the Pipeline, which reduces the depth of cover of the Pipeline by approximately 30 cm. The result is that the Pipeline is no longer at the standard depth of cover (approximately 1.0 m) which increases the potential for a future third party damage.

d) *Potential for resource constraints around the holiday season*. With the bypass option Enbridge Gas would be required to add an additional emergency crew on stand-by for the duration of the tie-in work.

e) *Potential for significant customer loss during the heating season should an outage occur on the line while the bypass option is being executed* (see Table 1 below).

For these reasons, Enbridge eliminated the bypass option.

In the original application, there were two options to tie-in the pipe: (1) to tie-in during the planned maintenance shutdown of a large volume customer, and (2) to use a bypass if the planned maintenance option was missed in Fall 2019. As a result of the permitting delays, the earliest that the tie-in could occur if the bypass option is utilized would be December 2019, with completion in Q1 2020.

Enbridge Gas explained that, in its view, it will only be using the Bridge for an additional three months, with the deferred tie-in option, as Enbridge was delayed in starting construction of the Pipeline due to permit delays. In Enbridge's view, using the Bridge for up to an additional three months does not outweigh the operational risks and network constraints associated with the bypass option outlined above. Enbridge Gas noted that it had taken steps to mitigate the risk of the Bridge failing by executing a bridge abutment remediation plan, which used articulated concrete block mats to mitigate against further erosion of the riverbank around the abutment[2]. This work was completed in September of 2017 and reduced the probability of Bridge failure in 5 years from 4.90% to 2.47%. This equates to a 50% reduction in the probability of Bridge failure in 5 years, and is the reason that Enbridge Gas believes the risk of the extended use of the Bridge is acceptable.

In its letter of November 28, 2019, Enbridge Gas provided commentary on the operational risks and costs associated with the two risk scenarios: a Bridge failure and a bypass failure. The results are summarized in Table 1: Risk Analysis.

[2] Exhibit B, Tab 1, Schedule 1, Page 6

Table 1: Risk Analysis

Option	Risk	Timing of Risk	Customer Losses	Cost ($ Millions)
(a)	(b)	(c)	(d)	(e)
Delay Tie-in	Bridge Failure in 5 Years	Spring	51,000	$19.1
Perform By-Pass	By-Pass Failure	Winter	92,500	$36.2

Findings

Based on its review of the November 1 and November 28, 2019 correspondence from Enbridge Gas, the OEB finds that the variance proposed by Enbridge Gas is the preferred option. The OEB hereby approves the proposed variance.

Yours truly,

Original Signed By

Christine E. Long
Registrar and Board Secretary

c: Mr. Guri Pannu, Guri.Pannu@enbridge.com

ENBRIDGE GAS INC.

Answer to Interrogatory from
Vulnerable Energy Consumers Coalition ("VECC")

Interrogatory

Reference:

EB-2018-0108, Exhibit D, Tab 1, Schedule 1, page 1

Question:

The following construction schedule was provided for the Don River Replacement Project at the above reference:

1. The proposed construction schedule is as follows:

    - Expected LTC Approval December 2018
    - Receipt of Permits and Approvals December 2018
    - Commence Construction January 2019
    - Completion of Construction September2019
    - Completion of Reinstatement October2019
    - Final Inspection December 2020

a) Please provide the actual construction schedule with a short explanation as to the reason for any significant time variances from the original Schedule as shown.

Response

An updated construction schedule for the Project can be found below:

- Completion of Construction April 2020
- Completion of Reinstatement May 2020
- Final Inspection December 2020

Reasons for the time variances relative to the original schedule are outlined in the vary request provided in Exhibit I.VECC.1.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Vulnerable Energy Consumers Coalition ("VECC")

Interrogatory

Reference:

Exhibit B, Tab 2

Question:

Enbridge filed for leave-to-construct the Don River Replacement Project on July 18, 2018. Board approval of that application was given November 29, 2018. The project was originally forecast to be completed within 2019. The ICM request was not made until October 8, 2019. Given these timelines it is clear that the project was part of the 2019 capital budget making Enbridge's request post facto rather than, as the ICM policy contemplates, anticipatory. Furthermore, the Board declined to provide ICM treatment for this project in the project EB-2018-0305. Given these facts please explain what circumstances have changed which support a change in the Board's prior decision.

Response

Enbridge Gas forecasts all projected ICM projects in its Asset Management Plan. The Don River Replacement Project was budgeted in 2019 and was expected to be in-service in October 2019. However due to circumstances beyond the control of Enbridge Gas, the in-service date was delayed to May 2020. As presented at Exhibit B, Tab 2, Schedule 1, page 18, the main driver for the change of in-service was a delay in obtaining the necessary permits. Enbridge Gas filed a Request to Vary (EB-2019-0275) on October 15, 2019 for the Don River Replacement Project which was approved by the Board on December 5, 2019.

In the Decision and Order dated September 12, 2019 in Enbridge Gas's 2019 Rates Application, EB 2018-0305, the Board stated, "$13.4 million related to IT spending will be removed from the 2019 in-service capital forecast used to determine the maximum eligible incremental capital for the EGD rate zone. This reduction reduces the starting point of the 2019 in-service capital from $481.7 million to $468.3 million. The resulting maximum eligible incremental capital drops from $13.1 million to negative $200,000. Consequently, there is no room for any ICM funding for the EGD rate zone. Accordingly, the Don River project does not qualify for ICM funding."

The Board did not decline to provide ICM treatment for the Don River Project on the basis of the need or prudence of the project, but on the basis of the change in the Maximum Eligible Capital Amount, as compared to the In-service capital at that time. As noted in Exhibit B, Tab 2, Schedule 1, pages 18 and 19, “the identification of risks and the execution of projects is dynamic.” As a result, “the delay to the implementation of the Don River Replacement project and other change to the 2020 portfolio resulted in reprioritization of capital outlined in the Addendum in Table 2.1-1. As such, the in-service capital for 2020 was revised, allowing Enbridge Gas to accommodate a portion of the Don River replacement project within the ICM threshold, leaving $26.8 million of in-service capital requiring ICM funding.”

Enbridge has demonstrated that the Don River Replacement Project meets the ICM criteria of materiality, need and prudence for this Rates Application.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Vulnerable Energy Consumers Coalition ("VECC")

Interrogatory

Reference:

EB-2018-0108, Exhibit D, Tab 2, Schedule 1, page 1

Question:

The following table was provided in EB-2018-0108 for the construction costs of the Don River Replacement project:

TOTAL ESTIMATED PROJECT COST

Item No.	Description	Cost
1.0	Material Costs	$710,107
2.0	Labour Costs	$17,060,285
3.0	External & Regulatory Costs	$860,000
4.0	Land Costs	$301,000
5.0	Overhead Costs	$759,000
6.0	Contingency Costs	$5,907,147
7.0	Total Project Cost	$25,597,539

Source EB-2018-0108 Exhibit D, Tab 2, Schedule 1, page 1 2018-07-04

a) Please update this table to show the actual costs.

b) For each category please explain the reason(s) for any material variance.

Response

a) & b)

The updated cost estimate of the Don River replacement project is $35.4 million as provided at Exhibit I.EP.16, page 2 in EB-2018-0305 (reproduced at Exhibit I.BOMA.6). The Project is not complete so actual costs have not yet been finalized. Actual Project costs and variances will be provided in the Post Construction Financial Report that will be filed with the Board pursuant to the Conditions of Approval for the Project. Also, see Exhibit I.CME.3.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Vulnerable Energy Consumers Coalition ("VECC")

Interrogatory

Reference:

Exhibit B, Tab 2, Schedule 1, page 15

Question:

a) Please confirm that EGI has not been granted leave to construct the Windsor Line Replacement (EB-2019-0172).

b) Does Enbridge agree that the "need" for the Windsor project is provided by the Board in the approval (or not) of the leave-to-construct application? If not please explain what regulatory purpose the LTC application serves.

Response

a) Confirmed.

b) Enbridge Gas agrees that the need for the Windsor Line Replacement Project must be demonstrated through the leave to construct application before the Board will grant approval.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Vulnerable Energy Consumers Coalition ("VECC")

Interrogatory

Reference:

Exhibit B, Tab 2, Schedule 1, page 15 &
EB-2019-0172 Exhibit C, Tab 4, Schedule 1.

Question:

The following table was provided with respect to the Windsor Line Replacement project in EB-2019-0172.

TOTAL ESTIMATED PROJECT COSTS

Windsor Line Replacement	**Mainline**	**Stations**	**Services**	**Total**
Materials	$4,164,000	$1,572,000	$133,000	$5,869,000
Construction and Labour	$62,521,000	$9,031,000	$2,515,000	$74,067,000
Contingencies	$9,975,000	$1,591,000	$397,000	$11,963,000
Interest During Construction	$725,000	$120,000	$0	$845,000
Estimated Incremental Project Capital Costs	**$77,385,000**	**$12,314,000**	**$3,045,000**	**$92,744,000**
Indirect Overhead	$11,729,000	$1,866,000	$466,000	$14,061,000
Total Estimated Project Capital Costs	**$89,114,000**	**$14,180,000**	**$3,511,000**	**$106,805,000**

a) Please confirm (or modify as necessary) that these are the current cost estimates for the Windsor Line Project.

Response

Confirmed. This is the current estimate for the Windsor Line Project.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Vulnerable Energy Consumers Coalition ("VECC")

Interrogatory

Reference:

Exhibit B, Tab 2, Schedule 1, page 15, Table 7

Question:

a) Enbridge footnotes Table 7 stating : "The total project in-service capital amount was reduced so that the total project ICM funding request did not exceed the maximum eligible incremental capital from Table 6." It is unclear to us what is being said here. Please explain why is the ICM funding request differs from the Total Project In-service amount as shown in Table 7.

Response

The calculation for the maximum eligible incremental capital for each rate zone is shown in Exhibit B, Tab 2, Schedule 1, Table 6, page 14. The in-service capital amounts for the Don River Replacement and Windsor Line Replacement projects shown in Table 7 exceed the maximum incremental capital eligible to each rate zone. As a result, the funding request is less than the total in-service capital for the projects, meaning that Enbridge Gas will have to accommodate a portion of the in-service capital for these projects within the ICM Threshold.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Vulnerable Energy Consumers Coalition ("VECC")

Interrogatory

Reference:

Exhibit B, Tab 2, Schedule 1, Appendix A, page 3, Table E

Question:

a) For the EGD rate zone please explain the reason(s) for the extraordinary amount of main replacement budgeted for 2022 ($244.2 million as compared to approximately $19 million spent on average in the 2014-2018 period).

b) During the historical period 2014 through 2018 Enbridge spent on average $100m in system renewal capital projects. In 2020 the same category of spending attracts $160.8 million in spending and this trend continues to increase over the remaining five years. Please explain the reasons for this extraordinary increase in this category of capital spending.

Response

a) Please see Exhibit I.SEC.1.

b) Please see Exhibit I.SEC.1.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Vulnerable Energy Consumers Coalition ("VECC")

Interrogatory

Reference:

Exhibit B, Tab 2, Schedule 1, Appendix A, page 3, Table F

Question:

Similar to the EGD rate zone, in the Union rate zone system renewal capital expenditures are forecast to more than double from 2018 to 2020 ($102.5M as compared to $206.9M respectively). What are the drivers for the extraordinary increase in the average system renewal spending in the 2020 through 2023 period as compared to the prior historical years of 2014 through 2018?

Response

Please see Exhibit I.SEC 1.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Vulnerable Energy Consumers Coalition ("VECC")

Interrogatory

Reference:

Exhibit B, Tab 2

Question:

What specific projects in the two rate zones would Enbridge be unable to complete in 2020 if the Board were not to approve the two ICM proposals.

Response

Enbridge believes that the Don Valley Bridge Project and the Windsor Pipeline Replacement Project meet the requirements for ICM treatment.

Enbridge filed a Leave to Construct for the Don Valley Bridge Project (EB-2018-0108). In its Decision and Order dated November 29, 2018, the OEB found that the Don Valley Bridge Project is needed to ensure the safe operation and reliability of the Don Valley Pipeline, as failure to address the risk associated with potential damage to the 89-year old bridge and existing pipeline could have a significant adverse impact on the gas supply to a large number of residential, commercial and industrial customers. Enbridge filed a Request to Vary on October 15, 2019 and in its Findings (EB-2019-0275) the OEB agreed that variance requested by Enbridge to defer the in-service date to May 2020 was the preferred option.

The Leave to Construct for the Windsor Pipeline Replacement is before the OEB at this time. As noted in Exhibit B, Tab 2 and in the Leave to Construct (EB-2019-0172), the pipeline must be replaced because of multiple concerns have been identified through Enbridge Gas' Integrity Management Program. These documents also outline the alternatives that were considered and the reason that this replacement alternative was selected. At $106.8M it represents a significant spend that cannot be accommodated within the Materiality Threshold.

Many factors were taken into consideration in the respective capital portfolios, such as asset condition, risk and opportunity, customer preferences, ratepayer impacts and the materiality threshold. Changes to these factors, as well as emerging risks and portfolio execution, will have an impact on capital planning and will be assessed at the time future decisions are made as the process is dynamic. As noted in evidence at Exhibit B, Tab 2 Schedule 1 page 19, “as these pressures are identified, trade-off decisions are made based on risk and available capital, a direct demonstration of EGD’s Plan-Do-Check-Act model.” In principle, material changes would compromise the Company’s ability to manage future years as the work would have a “snow plow” effect.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Vulnerable Energy Consumers Coalition ("VECC")

Interrogatory

Reference:

Exhibit B, Tab 3, Schedule 1, page 6

Question:

a) Prior to the new policy was it Enbridge's policy to provide a customer with a paper bill? If yes, during that time how could a customer select an e-bill option.

b) If a customer phones Enbridge to start a new account how are they billed?

c) Is there a charge for new accounts that is waived if the account is set up on-line?

d) Is it Enbridge's policy to not make a surcharge for paper bills?

e) If yes, please explain how the change in billing delivery default policy has been communicated to Enbridge customers.

f) Can a customer who receives an e-bill make payment by regular mail (i.e. by cheque?). If yes please explain how and where this explained to the customer (for example where is the billing address shown).

Response

a) Yes, the default option was a paper bill although customer enrolments completed via myAccount were enrolled in eBill automatically. A customer could select the eBill option themselves and they would almost always be encouraged to enroll as part of many customer interactions.

b) Beginning in January 2019, if the customer provided the contact centre agent an email address they were enrolled in eBill. If a customer does not provide an email address they are enrolled in paper billing.

c) No.

d) Yes. There is no surcharge for paper bills.

e) Each customer enrolled in eBill receives an email to setup their myAccount credentials. This email makes it clear to the customer that they can manage all aspects of their service from Enbridge Gas with myAccount including electronic bill delivery options (email, text, view within myAccount).

f) Yes. Customers can view a pdf of their bill within myAccount and the address where to make payment is shown on the top of the first page of the bill.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Vulnerable Energy Consumers Coalition ("VECC")

Interrogatory

Reference:

Exhibit B, Tab 3, Schedule 1

Question:

a) Did Enbridge receive explicit approval from any and all customers previously on paper bill and for whom it has since changed to e-billing?

b) Whom within Enbridge approved the policy to convert customers on paper bills to e-billing without the customers explicit consent?

c) Enbridge explains that its move to mandate e-billing is based on customer preference. If this is so then why do some customers continue to use paper bills?

Response

a) No, Enbridge Gas did not receive explicit approval to convert all customers who were switched to eBill. As described at paragraph 37 of Exhibit B, Tab 3, Schedule 1, there were customers who provided email addresses as part of a previous transaction who were converted to eBill and there were customers who interacted via the Enbridge Gas contact centres who provided an email address and were then defaulted to eBill.

b) Please see Exhibit I.CCC 5.

c) The evidence does not indicate that the move to mandate e-billing is based on uniform customer preference. The evidence makes reference to a variety of research about consumer expectations around overall self-service. Customers want to be able to manage their account and transactions using self-service tools to avoid having to contact by phone. These tools are not for everyone and some will continue to choose traditional channels like the Company's contact centers and paper bills. Enbridge Gas customers continue to have these options available to them.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Vulnerable Energy Consumers Coalition ("VECC")

Interrogatory

Reference:

Exhibit B, Tab 3, Schedule 1

Question:

a) Has Enbridge every offered incentives or had promotions to attract customers to e-billing?

b) If yes, please explain what promotions it has undertaken in the last three years and the number of customers in each year that converted to e-billing as a result of those promotions.

Response

a) and b)

Yes, Enbridge Gas has offered promotions and incentives to attract customers to e-billing. Examples of these activities are thermostat offers (both contest and coupon codes), contests to win cash prizes, gas BBQs and "gas for a year" and modest on-bill credits. Campaigns were typically in market for 3-4 months. Enbridge Gas does not have historical data on the number of customers enrolled in each promotion. These campaigns were in addition to regular activity in the Enbridge Gas contact centres to convert customers to eBill.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Vulnerable Energy Consumers Coalition ("VECC")

Interrogatory

Reference:

Exhibit B, Tab 3, Schedule 1

Question:

a) Please provide the Committee or other decision briefing/presentations that were provided to the approval body of the new e-bill policy.

b) Does the e-billing policy apply to both Union and EGD rate zones?

Response

a) Please see Exhibit.I.CCC.5.

b) Yes.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Vulnerable Energy Consumers Coalition ("VECC")

Interrogatory

Reference:

Exhibit B, Tab 3, Schedule 1, pages 18-

Question:

a) Please explain all the ways in which an Enbridge customer might provide an email address to the Utility.

b) What due diligence did Enbridge do in order to ascertain that an email provided to the Utility during a different unrelated transaction was suitable to be used for billing purposes?

c) Since the start of the new policy how many customers to date has Enbridge converted to e-billing as a result of this policy? Please distinguish by EGD and Union rate zones.

d) Of the total in c) how many of the customers converted have been mailed notice that they were being converted to e-billing?

e) Please provide a sample copy of the letter provided to customers who were involuntarily converted to e-billing.

f) When a customer provides an email address for a purpose other than to explicitly and voluntarily change to e-billing how are they informed that having provided an email address they will now be put on e-billing?

g) What was the date of the start of the new policy which converted customers with email address to e-bills?

Response

a) An Enbridge Gas customer may provide an email address by:

- Registering for a MyAccount profile
- Editing their email address in MyAccount
- Calling into either the main call centre or the customer ombudsman

b) The only email addresses considered eligible for eBilling purposes were listed either on the core Customer Information System (CIS) account record or on the customers' web-based MyAccount profile. These both represent the main repositories for customer account details gathered from customers directly. Emails obtained through any other means were not included.

c) The numbers of customers converted to eBilling to date can be found at paragraph 37 (ii) in Exhibit B, Tab 3, Schedule 1 of the evidence. The total number of customers is in the EGD rate zone is incorrectly shown as 331,480. The amount should be shown as 358,384. Enbridge Gas will file a correction to the evidence with the interrogatory response. Please see also Exhibit I.CCC.4 for information about the number of customers who reverted back to paper billing.

d) All customers received notice by email. As indicated at section 37 (ii) in Exhibit B, Tab 3, Schedule 1, customers in the first phase of the conversion also received notice by mail. The number of converted customers in the first phase was 147,756.

e) Please see Attachment 1 to the interrogatory response.

f) When customers are added to eBill after having provided their email address as part of an interaction with a customer service representative (for example, as part of a move transaction), they receive an email prompting them to create their online profile at Enbridgegas.com.

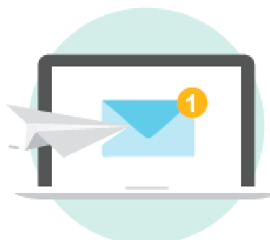
g) January 1, 2019.

Direct Mailer

Front

ENBRIDGE
Life Takes Energy

Your bill. Now, in your inbox.



Mr. Sample Mail
1234 Ebills Pilot
City, ON E0N0B0

Dear Sample Mail,

Last month, your bill was delivered electronically instead of by mail. Going forward, we'll continue to send your eBill to the email address shown below. If this needs to be updated, you can do that at **EnbridgeGas.com/myaccount** to ensure you receive your eBill.

Your email address: **email@email.com**

The benefits of eBill stack up	eBill	Paper bill
Mail delivery		✓
Get your bill sooner We'll send an email when your monthly bill is ready, with the amount due and a convenient PDF attachment.	✓	
Enjoy email reminders A week before payment is due, we'll send a quick note to remind you.	✓	
Reliable and convenient With your eBill delivered right to your inbox every month, you'll always know where to find it.	✓	

*No purchase necessary. Contest is open to active Enbridge Gas residential customers. One entry per household. Thirteen separate draws, each for a $1,000 credit to customers Enbridge Gas account, will take place between January 1st 2019 and March 31st 2019. Chances of winning depend on the number of eligible entries received. Contest closes March 31st 2019 at 11:59 pm.

Get the most of My Account

It's easier than ever to manage your account online

- Manage your contact details and preferences
- See payment history
- Submit a move request
- **More new features on the way!**

We respect your preference

If you don't find eBill to be the most convenient option, you can switch back online at any time.

Inside

ENBRIDGE GAS INC.

Answer to Interrogatory from
Vulnerable Energy Consumers Coalition ("VECC")

Interrogatory

Reference:

Exhibit B, Tab 3, Schedule 1, pages 3 – 9

Question:

a) At the above reference Enbridge discuss and cites a number of behavioral and secondary customer preference studies. Did Enbridge engage any expertise outside of the Utility to determine its customers preferences?

b) If yes, please provide their report(s).

c) Other than the antidotal and third-party reports reference in Exhibit B what specific customer surveys or other quantitative analysis did Enbridge undertake on the revised policy prior to its implementation.

Response

a) & b) No.

Enbridge Gas reviewed and considered a variety of secondary sources and other published research on this issue. General consumer trends and preferences is a well-researched topic. A number of these studies are referenced in the evidence. Enbridge Gas is a customer of well-known organizations like Gartner that provide cross-industry research on a variety of topics including customer service and evolving expectations of customers.

c) Please see Exhibit I.Staff.9 a) and Exhibit I.CCC.2.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Vulnerable Energy Consumers Coalition ("VECC")

Interrothgatory

Reference:

Exhibit B, Tab 3, Schedule 1, page 9 –

Question:

a) Please provide the CX program business program materials including any documents provided the CEB Inc.

b) If yes, please provide their report(s).

c) What billing payment program conversions has CEB Inc. been involved with prior to their engagement with Enbridge?

Response

a) & b)

CEB Inc. (now Gartner) was not engaged by Enbridge Gas to complete work relating to the Company's CX Program and Enbridge Gas did not provide any materials to CEB Inc. As described at the reference noted Enbridge Gas leveraged the outcomes of research completed by CEB Inc. in the Company's internal design of the CX Program. This research was neither prepared for, or specific to, Enbridge Gas. A summary of the research in question is publicly available at https://hbr.org/2010/07/stop-trying-to-delight-yourcustomers.

c) None. Enbridge Gas leveraged research from CEB Inc. (Gartner) to guide the overall CX strategy around driving a low-effort experience with increased self-service.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Vulnerable Energy Consumers Coalition ("VECC")

Interrogatory

Reference:

Exhibit B, Tab 3, Schedule 1, page 13 –

Question:

Enbridge Gas established four primary metrics to track progress and measure the success of its CX Program:

i) Call reduction of 20% by year 3;
ii) Work automation increase of 20% by year 3;
iii) Increase in eBill adoption to 50% by year 3; and,
iv) Increased customer satisfaction.

a) What was the date when Enbridge established the four metrics listed above?

Response

a) Call reduction and work automation were metrics implemented by Enbridge Gas in January 2017. eBill adoption and customer satisfaction are metrics that have been utilized by Enbridge Gas for at least the last ten years. Formal targets for these metrics were established as part of approving the legacy EGD CX program in October 2017.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Vulnerable Energy Consumers Coalition ("VECC")

Interrogatory

Reference:

Exhibit B, Tab 3, Schedule 1,

Question:

a) Please provide the number of late payment notices issued for each of the past 24 months (to present).
b) For the past 24 months to present Please provide the number of contacts (email and telephone) to Enbridge which were related to either

- late payment charge complaint
- no bill received complaint
- bill delivery or bill format change complaint

Response

a) Late Payment notices can include any of the following notices. Bill Message on the monthly invoice (Once per month). All collection notices via Dialer, Email and Text. (see call chart below)

2018	
Month	**Total Outbound Notices**
2018-1	54,110
2018-2	54,169
2018-3	72,757
2018-4	66,587
2018-5	66,351
2018-6	75,470
2018-7	67,986
2018-8	60,934
2018-9	52,874
2018-10	50,756
2018-11	47,136
2018-12	36,346
Total	**705,476**

2019	
Month	**Total Outbound Notices**
2019-1	48,623
2019-2	46,522
2019-3	58,445
2019-4	63,448
2019-5	77,368
2019-6	67,671
2019-7	84,348
2019-8	105,021
2019-9	103,468
2019-10	90,943
2019-11	85,719
2019-12	73,174
Total	**904,750**

b) Enbridge Gas does not track inbound calls and emails that are strictly complaints about late payment charges, no bill received or bill delivery.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Vulnerable Energy Consumers Coalition ("VECC")

Interrogatory

Reference:

Exhibit B, Tab 3

Question:

a) Please confirm that no representative of Enbridge has ever claimed to any customer that they are, or will be in the future, be required to use e-billing.

b) Please confirm that Enbridge has at all times represented that paper bills will be provided if requested and at no additional cost.

c) Please confirm that any and all customers who did not provide explicit consent to be changed from paper to e-billing and who subsequently complained about a late payment charge were refunded any and all penalties. (that is are the 8,482 Enbridge and 2,968 Union zone customers the sum of all complainants with respect to late payment who were converted e-bill customers)?

Response

a) Confirmed. Enbridge Gas representatives have never been directed to indicate to customers that eBilling is an absolute requirement. If a customer insists on paper billing they are put on that option. Like other elements of service delivery, this is monitored through ongoing quality assurance processes.

b) Enbridge Gas confirms that scripting and messaging has always reflected that paper bills are available at no additional cost to any customer requesting them. As indicated in part a) above, the delivery on this direction would also be monitored through ongoing quality assurance processes.

c) Confirmed. Any converted customer that contacted Enbridge Gas to complain about late payment penalties would have had the related late payment penalties reversed. The numbers of such complaints received is as referenced in the evidence (paragraph 49) and in this question.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Vulnerable Energy Consumers Coalition ("VECC")

Interrogatory

Reference:

Exhibit B, Tab 3, Schedule 1, Appendix A, page 13

Question:

a) Is the web page shown at page 13 the only page on which to choose type of bill delivery?

b) The reference web page does not appear to show an option to receive a paper bill. Please confirm this is correct or explain how one choose a paper bill home delivery option from this (or some other) page.

Response

a) Yes, this is the only page within the Enbridge Gas myAccount portal that sets out bill delivery options.

b) Correct. A customer who is receiving an eBill and wishes to switch to paper bill needs to call Enbridge Gas's contact centre.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Vulnerable Energy Consumers Coalition ("VECC")

Interrogatory

Reference:

Exhibit B, Tab 3, Schedule 1, page 24

Question:

a) Please explain more fully the meaning of "challenges in April and May of 2019 relating to the direction of payments to the appropriate legal entity."

b) What is the evidence that the drop in customer satisfaction in early 2019 was the result of the Union-Enbridge branding change as opposed to the e-billing policy change – or some other factors?

Response

a) There were challenges related to the rebranding/co-branding of Legacy Union Gas. Canadian Banks received direction from Enbridge Gas that they should change the payee name of Union Gas to Enbridge Gas. As a result, when customers made payments electronically they were presented with Enbridge Gas twice in the list of service providers. This caused significant confusion for a period of time resulting in mis-directed payments until the Company took immediate action to resolve this issue and have banks list the payee name as Enbridge (Union Gas).

b) There is no definitive evidence to substantiate this, however, based on the voice-of-the-customer feedback, the Company understands that confusion around mis-directed payments was a significant issue.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Vulnerable Energy Consumers Coalition ("VECC")

Interrogatory

Reference:

Exhibit B, Tab 3, Schedule 1, page 1

Question:

At the above reference Enbridge makes the following statement: "As indicated in the Settlement Proposal, Enbridge Gas believes that its change in practice is appropriate and does not believe that any Board approval was or is required."

a) Please clarify. Is it Enbridge's position that Board approval is not required to change the default billing method (paper delivered or electronic)? If so, in addition to bill delivery, is it also Enbridge's position that the Board may not order the acceptable methods of bill format or the method of payment (e.g. cash, cheque, e-transfer etc.)?

b) If its Enbridge's position that the Board does not have the jurisdiction to establish conditions with respect to the Utility's billing practices please provide the basis of that opinion. Specifically, please address the relevance (or not) of Enbridge Gas Distribution Inc. v. Ontario (Energy Board) (2005), 74 O.R. (3d) 147, (2005), 193 O.A.C. 180 Ontario Court of Appeal and the Board's Decision in Enbridge Gas Distribution EB-2005-001/EB-2005-0437 where the Board stated in part:

> DEEHS submitted that the Board does not have the jurisdiction to make an order or grant remedies concerning billing arrangements related to non-commodity services and products. To the contrary, in the Board's view, Enbridge must maintain and demonstrate effective control over its billing and any sharing which takes place on the bill it uses. **The Board does have jurisdiction over the regulated activities of Enbridge, including how Enbridge charges for its services and its billing arrangements. This view has been upheld by the Court of Appeal in its September 2004 decision regarding the Gas Distribution Access Rule**. The contractual relationships may have been organized such that Enbridge does not provide the billing services directly; it purchases

> the service from CWLP. However, this is essentially a utility bill. (page 64 – emphasis added)

c) If it is Enbridge's opinion that the Board does not have jurisdiction in the matters of the form and means of billing and payment then why has Enbridge agreed to put the matter before the Board in this proceeding?

Response

a) to c)

Enbridge Gas's position is that no Board approval is required to change the default billing method. This was not, and is not, a matter that is addressed in the relevant customer service rules that apply to Enbridge Gas.

In this regard, it is important to note that the Board recently completed an extensive review of customer service rules for gas and electricity customers (EB-2017-0183), including extensive review relating to billing and payment.

The Board's EB-2017-0183 Report on the Review of Customer Service Rules for Utilities (September 6, 2018) and the subsequent Notices of Amendments to Codes and a Rule (December 12, 2018 and March 14, 2019) make no mention of new rules or requirements relevant to eBill. Presumably, if the Board felt it important to prescribe rules related to how eBill is to be offered and administered, then these would have been included in the new customer service rules set out in the Gas Distribution Access Rule (GDAR) amendments. No such new rules were included. The Board did, however, indicate its expectation that gas utilities will expand the use of eBill to offset expected cost increases resulting from the implementation of new customer service rules ("Utilities are also expected to explore other opportunities for cost savings such as expansion of e-billing, enhanced and timely communication with customers, and improved collection processes").

Enbridge Gas acknowledges that the Board has jurisdiction to establish rules related to a distributor's billing practices. However, as of the current date, no such rules have been established by the Board that are relevant to the issues raised by intervenors about eBill.

Similarly, Enbridge Gas acknowledges that the Board has jurisdiction to prescribe and make rules related to acceptable methods of bill format or payment. However, it is Enbridge Gas's position that the Company's actions to make eBill the default billing method are not in contravention of any orders or rules that the Board has made and/or implemented.