ENBRIDGE GAS INC.
Answer to Interrogatory from
Board Staff (STAFF)

Reference: Exhibit A – Letters of Comment

Question:

Following publication of the Notice of Application, the OEB received several letters of comment. Sections 2.1.6 of the Filing Requirements state that distributors will be expected to file with the OEB their response to the matters raised within any letters of comment.

Please file a response to the matters raised in the letters of comment that were also copied to Enbridge Gas Inc. (Enbridge Gas). Going forward, please ensure that responses to any matters raised in subsequent comments or letters that the applicant receives are filed in this proceeding. Please ensure that name and contact information is redacted for public filings. All responses must be filed before the argument (submission) phase of this proceeding.

Response

As of April 25, 2019, Enbridge Gas received 141 letters of comment. As per the Board's Decision and Procedural Order No. 2, Enbridge Gas will provide a response to the letters received before the close of record for this proceeding.[1]

[1] Decision and Procedural Order No. 2, April 1, 2019, page 7.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Board Staff (STAFF)

Reference: Exhibit A1/Tab 5/Schedule 2/Pg. 11, Exhibit B1/Tab 1/Schedule 1/Appendix H and Staff Interrogatory #3, EB-2018-0131

Question:

In the Conditions of Service, Enbridge Gas notes that to connect an applicant (customer) to the distribution system, Enbridge Gas completes a construction estimate to assess the costs associated with the installation and that applicants may be required to pay a contribution in aid of construction (CIAC) as the share of the costs to make the installation financially feasible.

In response to an OEB staff interrogatory in the EB-2018-0131 proceeding, Enbridge Gas indicated that prior to 2015, Enbridge Gas Distribution provided a threshold of 20 meters for standard residential service connections and customers were required to pay the appropriate CIAC when the service length exceeded the threshold. Since 2015, it has refined its approach to determine feasibility using the “grid method” which uses actuals for each Forward Sorting Area (FSA). Under this approach, Enbridge Gas is able to account for variability in customer circumstances when assessing the CIAC amount for residential infill service connections. The CIAC amount for residential infill customers is now determined by individually estimating the revenue allowance and the service cost estimate which is typically a regionally tailored estimate based on historical data from similar services in the same area (FSA). The amount of service cost in excess of the revenue allowance is the CIAC amount which is recovered from customers before service installation. The PI of each customer connection is brought to 1.0 under this scenario. Enbridge Gas noted that collection of the CIAC serves to ensure that new customers bear the cost of providing new services without causing undue burden on existing customers, as prescribed by EBO 188 guidelines. For 2017, Enbridge Gas collected over $8 million in contributions as a result of changes to the Conditions of Service.

a) The Conditions of Service do not explicitly explain these changes. Has Enbridge Gas provided this information on its website and is the information easy to locate on the website? Please provide a detailed response.
b) Has Enbridge Gas communicated the change to builders and other business customers that are likely to be impacted as a result of the policy change?
c) In Enbridge Gas’ opinion, was it the intent of the OEB in the EBO 188 guidelines that the utility should calculate the PI for every individual customer and bring the PI of each customer connection to 1.0? If that is the intent, please explain why

the OEB in its report recommends a PI of 1.0 for the Rolling Project Portfolio and not for individual customer connections (Final Report of the Board, January 30, 1998, EBO 188)?

d) Please provide the amounts collected in CIAC for 2018 as a result of changes to the Conditions of Service where the PI is determined for each infill customer.

e) Union Gas in its Conditions of Service (Exh. A1/Tab 5/Sch. 3/pg.14) still provides customers with 30 meters of service installation at no cost. Why is Union Gas' Condition of Service different from that of Enbridge Gas Distribution? Does Enbridge Gas intend to harmonize the Conditions of Service and calculate the PI for each Union Gas infill customer? If yes, please provide the timeline.

f) Enbridge Gas' existing rates assume a certain number of new customer additions each year and its capital expenditure plan includes certain dollars earmarked for providing infill customer connections. Since these costs are included in current rates, why did Enbridge Gas implement a change to the Condition of Service in a year when its costs and revenues were not examined under a cost of service approach?

g) In its interrogatory response (referenced above), Enbridge Gas notes that upon rebasing, the modified approach to feasibility analysis will benefit ratepayers because the new amounts being added to utility rate base for residential infill customers will be lower than would be the case under the prior approach. Enbridge Gas will now rebase in 2024 and until then no adjustments to rate base will be made. Please provide the benefits that ratepayers will receive in rates until 2023 as a result of the change to the Conditions of Service. Please also explain why it was not appropriate to implement these changes at the time of rebasing?

h) Please provide the total estimated amount that Enbridge Gas is expected to collect from 2017 to 2023 as a result of changes to the Conditions of Service under which residential infill customer are expected to pay a CIAC for connecting to the natural gas distribution system.

i) Has Enbridge Gas received complaints from residential customers or builders after implementing this change to the Conditions of Service? If yes, please provide the number of complaints and the general theme of the grievances.

Response

a) & b) The Conditions of Service for the EGD rate zone describe the current policy and process employed to assess the economic feasibility of service connections. The Conditions of Service can be found easily by using an internet search engine to find "Enbridge Gas Conditions of Service". A PDF copy of the current Conditions of Service usually appears as the first item found. EGD personnel met with the members of Heating, Refrigeration and Air Conditioning Institute of Canada ("HRAI") to communicate this process change. HRAI is a trade association of HVAC contractors appliance manufacturers.

Also, when customers apply for a new service connection (either directly or through an HVAC contractor) and there is a project under consideration, Enbridge Gas clearly communicates the process to them. This communication sets clear expectations that a feasibility analysis will be carried out based on the estimated installation cost and there may be a cost (or CIAC) to install the service. Customers are also notified that they must agree to these costs before Enbridge Gas processes their application.

c) As described at paragraph 261 of Appendix B to the OEB's Guidelines for Assessing and Reporting on Natural Gas System Expansion in Ontario (the "Guidelines") the Board provided for a portfolio approach with the intent of allowing the utilities a greater degree of flexibility in determining which projects to undertake, while allowing the Board to retain regulatory oversight ensuring no undue cross subsidy or rate impacts would result from distribution system expansion. At paragraph 149 of the Guidelines the Board stated "In order to ensure fairness and equity in the application and design of contribution requirements, the Board finds that all projects must achieve **a minimum threshold P.I. of 0.8** for inclusion in a utility's Rolling Project Portfolio." (emphasis added) Enbridge Gas's view is that its service installation policy is consistent with the Guidelines.

d) Enbridge Gas does not have data required to determine the difference between the CIAC amount collected in 2018 and the CIAC amount that would have been collected in 2018 under the Company's former customer connection policy.

e) The Conditions of Service currently applied in the Union Gas rate zones evolved while Enbridge Gas Distribution and Union Gas were operating as independent corporate entities. Each entity addressed its customer connection policies differently. Now that the process of amalgamating Enbridge Gas Distribution and Union Gas into a single entity is in progress, steps will be taken to harmonize the Conditions of Service and other corporate policies. This activity is currently underway with the goal of implementing a harmonized customer connection policy before the next IR period.

f) The change in the customer connection policy was required to ensure that the Company's Investment Portfolio achieves a PI of greater than 1.0.

g) As noted in response to part f) above, the change was necessary to be compliant with EBO 188. The modified approach was adopted to comply with the regulation and ensure that economically feasible customers are attached to the system. If unfeasible customers are attached, utility earnings will be negatively impacted until rebasing. Upon rebasing, existing ratepayers would be negatively impacted because rate base would be higher compared to what it will be with the current approach to collecting CIACs.

h) In response Exhibit I.B.EGDI.STAFF.3 part d) in EB-2018-0131, Enbridge noted its limitation with respect to the provision of historical data for customer contributions related to infills. Prior to 2016, Enbridge systems were unable to distinguish between services contribution from residential infills and subdivision projects. As such, Enbridge Gas has no means to forecast a difference in collection of CIAC amounts before and after the Conditions of Service were changed.

i) Please see table below:

Connection Complaints

	Total New Connections	# of Complaints	T Themes
2015	31,533	367	Cost, Installation dates, Communication
2016	29,991	634	Cost, Installation dates, Communication
2017	34,005	444	Cost, Installation dates, Communication
2018	29,037	298	Cost, Installation dates, Communication
YTD 2019	4,730	91	Cost, Installation dates, Communication

ENBRIDGE GAS INC.
Answer to Interrogatory from
Board Staff (STAFF)

Reference: Exhibit B1/Tab 1/Schedule 1/pgs. 6-7

Question:

The Enbridge Gas Distribution rate zone has an approved methodology where the gas supply portfolio is updated in rates on an annual basis. Accordingly, gas cost rates have been adjusted for the Enbridge Gas Distribution rate zone to reflect changes to the 2019 gas supply portfolio (i.e. impact of supply mix change, net of price changes that are otherwise captured through the QRAM methodology), as well as changes in contracted storage and associated transported costs. The Ontario Energy Board in its Decision and Procedural Order No. 2 determined that it would not address the cost consequences of Enbridge Gas Distribution's 2019 Gas Supply Plan in this proceeding.

a) Please indicate if the gas cost consequences of Enbridge Gas Distribution's 2019 Gas Supply Plan have been reflected in prior QRAM applications. If yes, please provide details.
b) Please discuss the implications of the gas cost consequences of Enbridge Gas Distribution's 2019 Gas Supply Plan not being addressed in this proceeding.

Response

a) No, the gas cost consequences / impacts on rates stemming from changes to the 2019 gas supply portfolio (i.e. impact of supply mix change, net of price changes that are otherwise captured through the QRAM methodology), as well as changes in contracted storage and associated transportation costs have not been reflected in January 1, 2019 QRAM or April 1, 2019 QRAM applications.

b) The key implication of the gas cost consequences of the 2019 Gas Supply Plan for the EGD rate zone not being addressed in this proceeding is that currently there is no other Board-approved mechanism to recover (i.e. pass through to customers) the impact of the gas costs from the changes in the gas supply portfolio, contracted storage and associated transportation costs.

This is because the Board approved methodology[1] in the EGD rate zone contemplates these adjustments to rates as part of the annual rate setting mechanism. This is explained in the application at Exhibit B1, Tab 1, Schedule 1, page 6:

> The EGD rate zone has an approved methodology where the gas supply portfolio is updated in rates on an annual basis. Accordingly, gas cost rates have been adjusted for the EGD rate zone to reflect changes to the 2019 gas supply portfolio relative to the 2018 gas supply portfolio (i.e. impact of supply mix change, net of price changes that are otherwise captured through the QRAM methodology), as well as changes in contracted storage and associated transportation costs. Changes to these cost elements are not captured through the QRAM methodology for the EGD rate zone.

In the MAADs Decision, the Board did not direct any changes to this methodology. The Board approved the "Y-Factors" "as proposed by the applicants."[2] Gas costs are a Y-factor and Enbridge Gas had not proposed any changes to the methodology for passing through those costs.

The impact of the year-over-year changes in 2019 rates is approximately $1.48 per year[3] for a typical residential customer and approximately $4 million across all customers.

As per Procedural Order No. 3, the OEB is prepared to establish a 2019 Gas Supply Plan Cost Consequences deferral account for the Enbridge Gas Distribution rate zone that would track the proposed amounts from January 1, 2019 for recovery to be reviewed and disposed of as part of a future proceeding.

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[1] 2007 Rate application (EB-2006-0034), 2008-2012 Revenue Cap per Customer (EB-2007-0615), and 2014-2018 Custom IR (EB-2012-0459).

[2] MAADs Decision and Order (EB-2017-0306/2017-0307)

[3] See Exhibit F1, Tab 1, Rate Order, Working Papers, Schedule 3, Pages 2 and 10, Typical Residential Customer, Volume 2,400 m^3 Item 3.6 Total Sales ($4.26 at page 2 vs. $5.74 at Page 10)

ENBRIDGE GAS INC.
Answer to Interrogatory from
Board Staff (STAFF)

Reference: Exhibit B1/Tab 1/Schedule 1/pgs. 6-7

Question:

Enbridge Gas Distribution has modified the heat content reference in rate schedules, from the existing heat content of 38.42 MJ per m^3 to 38.53 MJ per m^3.

Please confirm if there is an impact on 2019 distribution rates as a result of changes to the heat content of natural gas. If yes, please provide the impacts.

Response

There is no impact on EGD's 2019 distribution rates resulting from the year over year change in heat content.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Board Staff (STAFF)

Reference: Exhibit B1/Tab 1/Schedule 1/pg. 12

Question:

The Enbridge Gas Distribution rate zone average use adjustment reflects the existing OEB-approved methodology to forecast the year over year change in average use consumption for Rate 1 and Rate 6 customers. The methodology relies on regression equations to estimate the underlying historical trend of average use. Driver variables have remained unchanged and coefficients of existing models are re-estimated to include the most recent year of actual data.

a) In the last Enbridge Gas deferral and variance accounts proceeding (EB-2017-0102), the utility acknowledged that the average use model was updated with the 2016 actual value and a diagnostic test indicated that a structural break occurred in 2016 for some models. Please confirm whether Enbridge Gas has rectified the issues identified in 2016. If not, please explain why.
b) Please explain the steps that Enbridge Gas has taken to ensure that the results to estimate the year over year change in 2019 average use are reliable.

Response

a) The addition of 2017 actual data confirmed that the abnormally large decline in 2016 average use was just an outlier and there is no structural break in 2017 in any of Enbridge Gas' models used to determine 2019 average use forecast.

   For its 2019 rate application Enbridge Gas hasn't changed its models and used the same models as its 2014 to 2018 rate application. The models are planned to be reviewed/tested once again at rebasing as directed by the Board (with the amended settlement proposal dated December 6, 2017, and with its Decision and Order August 30, 2018 for EB-2017-0306/ EB-2017-0307).

   Table 1 below shows the 10-Year history of Normalized Actual versus Board-Approved average uses normalized to each year's respective Budget degree days. The out-of-sample average percentage variance over the last 10 years is -0.5% for Rate 1 and 0.5% for Rate 6. The results support the view that the General Service average use forecasting methodology continues to be a reliable predictor for General Service average use.

TABLE 1
GENERAL SERVICE AVERAGE USE

Test Year	Rate Classes	Col. 1 Actual Normalized Average Use	Col. 2 Board-Approved Normalized Average Use	Col. 3 Variance Normalized Average Use	Col. 4 %Variance Normalized Average Use
2008	Rate 1	2,636	2,647	(11)	-0.4%
	Rate 6	24,869	24,204	665	2.7%
	Total General Service	4,493	4,449	44	1.0%
2009	Rate 1	2,616	2,637	(21)	-0.8%
	Rate 6	27,654	28,165	(511)	-1.8%
	Total General Service	4,659	4,770	(111)	-2.3%
2010	Rate 1	2,579	2,622	(43)	-1.6%
	Rate 6	29,106	27,949	1,157	4.1%
	Total General Service	4,403	4,705	(302)	-6.4%
2011	Rate 1	2,594	2,643	(49)	-1.8%
	Rate 6	29,471	28,029	1,442	5.1%
	Total General Service	4,764	4,726	38	0.8%
2012	Rate 1	2,529	2,510	18	0.7%
	Rate 6	28,941	30,122	(1,182)	-3.9%
	Total General Service	4,642	4,715	(73)	-1.5%
2013	Rate 1	2,547	2,568	(22)	-0.8%
	Rate 6	29,203	29,878	(675)	-2.3%
	Total General Service	4,665	4,719	(54)	-1.1%
2014	Rate 1	2,475	2,433	41	1.7%
	Rate 6	28,634	28,383	251	0.9%
	Total General Service	4,543	4,461	82	1.8%
2015	Rate 1	2,427	2,419	9	0.4%
	Rate 6	28,600	28,341	259	0.9%
	Total General Service	4,485	4,465	20	0.4%
2016	Rate 1	2,401	2,480	(79)	-3.2%
	Rate 6	28,203	28,753	(550)	-1.9%
	Total General Service	4,413	4,537	(124)	-2.7%
2017	Rate 1	2,485	2,472	13	0.5%
	Rate 6	29,462	29,058	404	1.4%
	Total General Service	4,569	4,538	31	0.7%

b) The key factor used to evaluate the accuracy of the General Service average use forecast is the percentage variance between normalized actual and normalized forecast average use per customer. As seen in Table 1 above, the results support the view that the General Service average use forecasting methodology continues to be a reliable predictor for General Service average use. Besides tracking historical accuracy through the percentage variances, the models also have been subjected to a battery of tests. The models' estimation and test results for 2019 forecast show that the models continued to have high R-squared, and to generate small forecast errors while passing most of the statistical specification tests. Therefore they continued to be good predictors of average use.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Board Staff (STAFF)

Reference: Exhibit B1/Tab 1/Schedule 1/pgs. 12-13

Question:

The MAADs Decision (EB-2017-0306/0307) accepted an annual adjustment to rates to reflect the declining trend in use. Enbridge Gas has applied existing OEB-approved methodologies for the Enbridge Gas Distribution and Union Gas rate zones to adjust rates to account for changes in average use/normalized average consumption.

a) Please provide the impact on 2019 proposed revenue requirement as a result of adjustments to average use/normalized average consumption.
b) Are these changes captured in the respective deferral and variance accounts?

Response

a) The 2019 proposed revenue is not affected by the changes in forecast/target average use. The proposed adjustments for changes in average use impacts the proposed 2019 unit rates only.

   When average use decreases (increases), rates must be increased (decreased) to maintain the same revenue. The forecasted/target average use for 2019 relative to the forecasted/target 2018 has increased between 1.7% to 2.3% in the EGD rate zone and between 3.0% to 4.8% in the Union rate zones. If the rates for 2019 were not reduced by a similar proportion, customers would be charged approximately an additional $9.5 million in the EGD rate zone and $11.7 million in the Union rate zones due to higher average use.

b) As indicated in a) above, the change in forecast/target 2019 average use has been reflected in 2019 proposed unit rates, and would therefore not be captured in the respective deferral accounts. Enbridge Gas has not proposed any changes to the AUTUVA and NAC deferral accounts for 2019. These deferral accounts will continue to capture the revenue impact, for general service rate classes, resulting from normalized actual average use which deviates from the forecast/target average use underpinning rates.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Board Staff (STAFF)

Reference: Exhibit B1/Tab 1/Schedule 1/pg. 18 and Appendix A/pgs. 1-5

Question:

In the MAADs proceeding, the applicant indicated that post amalgamation, contracts between Enbridge Gas Distribution and Union Gas will cease to exist. The accounting order with respect to the Purchase Gas Variance Account removed the reference to recording amounts related to Limited Balancing Agreement with Union Gas.

a) Different rate zones still exist for Enbridge Gas Distribution and Union Gas. Please explain how the removal of the amounts relating to the Limited Balancing Agreement will impact the amounts being allocated to customer groups in different rate zones.
b) After the Limited Balancing Agreement is ceased, please explain whether revenues/costs are still tracked between the different rate zones.

Response

a) As part of the MAADs proceeding, Enbridge Gas indicated that upon amalgamation it planned to discontinue charging Limited Balancing Agreement ("LBA") fees between the Union rates zones and the EGD rate zone[1]. LBA fees were previously charged at interconnections between legacy Union and legacy EGD on daily and cumulative imbalances outside of agreed upon tolerances. Upon amalgamation, LBA fees are no longer required as Enbridge Gas operates an integrated system for all rates zones.

   Prior to amalgamation, the revenue from the LBA was recorded in Union's Short-Term Storage and Other Balancing Services deferral account (179-70) of which 90% was credited to the benefit of Union's in-franchise customers. The cost of the LBA was recorded in EGD's Purchase Gas Variance Account as a charge to EGD's customers.

   The impact to Enbridge Gas customers in the different rate zones related to the LBA are not a material benefit or cost. Table 1 provides the LBA fees charged by legacy Union to legacy EGD from 2013 to 2018.

[1] EB-2017-0306/EB-2017-0307, Exhibit C.SEC.1, Attachment 1, p.3.

Table 1
LBA Fees Charged by Union to EGD

Line No.	Particulars ($000's)	LBA Fees
		(a)
1	2018	430
2	2017	381
3	2016	968
4	2015	282
5	2014	237
6	2013	360

b) No, the Limited Balancing Agreement revenues/costs are not tracked between the different rate zones. LBA fees are no longer required as Enbridge Gas operates an integrated system for all rates zones.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Board Staff (STAFF)

Reference: Exhibit B1/Tab 1/Schedule 1/pgs. 19-21

Question:

The MAADs Decision directed Enbridge Gas to add rate base and depreciation associated with Union Gas' capital pass-through projects to the 2013 OEB-approved rate base and depreciation in determining the eligible incremental capital amount for the Union Gas service territory. Enbridge Gas has therefore proposed to fix the capital pass-through revenue requirement in rates and discontinue the use of capital pass-through deferral accounts, except for the purpose of capturing utility tax timing variances.

a) Please provide further details as to why Enbridge Gas is proposing to amend the capital pass-through deferral accounts so that it only captures a portion of the revenue requirement impact related to the projects.
b) For the capital pass-through projects, please confirm that the variances between Enbridge Gas' revenue requirement adjustment excluding utility tax timing differences in this application and actual revenue requirement excluding utility tax timing differences could be material.
c) Table 6 shows the actual/forecast utility tax timing differences from 2014 to 2018, and table 7 shows the forecast utility tax timing difference for 2019 to 2023. For 2014 to 2018, and 2019 to 2023, please provide a table showing the difference between approved (or forecasted to be approved) and forecasted revenue requirement recorded in the capital pass-through deferral accounts, broken down by the portion relating to tax timing differences and the remaining revenue requirement.

Response

a) As a direct result of the MAADs Decision, which directed Enbridge Gas to add rate base and depreciation associated with the capital pass-through projects to determine the ICM threshold value[1], Enbridge Gas requires: a one-time adjustment to rates to include the revenue requirement of the capital pass-through projects; and continuation of the capital pass-through deferral accounts to capture the utility tax timing differences only. These changes are required to align the ICM threshold value with the capital investment that can be supported by rates.

<u>One-time Adjustment</u>
The capital pass-through funding as a Y factor provides for incremental revenue to support the revenue requirement of the capital pass-through projects only. It does not support the funding of any additional capital. When the actual revenue requirement of the projects is passed through to customers each year through rates or the deferral account, customers benefit from the normal decline in return on the capital pass-through projects rate base and there is no incremental revenue related to PCI or growth for these projects. As a Y factor, there is no opportunity to fund incremental capital investments as assumed when the depreciation and rate base are added to the ICM threshold value calculation.

By adding the 2019 forecast rate base and depreciation of the capital pass-through projects in the ICM threshold calculation, the 2019 ICM threshold value for the Union rate zones is $80.7 million[2] higher than what rates can support when capital pass-through projects are treated as a Y factor.

Enbridge Gas has proposed to include a one-time adjustment for the capital pass-through revenue requirement in 2019 rates[3] to address the disconnect that would otherwise be created between the annual capital investment supported by rates and the ICM threshold value calculation. The proposal for a one-time adjustment aligns rates with the amount assumed to be funded through rates, as determined in the ICM threshold value calculation. The basis of the ICM threshold value calculation assumes that rate base, as supported by rates, is maintained through the reinvestment of the depreciation amount and additional capital funding is available from applying the PCI and growth to that rate base annually.

[1] EB-2017-0306/EB-2017-0307, Decision and Order, August 30, 2018, pp. 32-34.
[2] The ICM threshold value without the capital pass-through rate base and depreciation is $294.5 million compared to the $375.2 million including the capital pass-through rate base and depreciation.
[3] The capital pass-through revenue requirement has been updated to reflect the 2019 forecast. Refer to Exhibit I.LPMA.7 c).

To illustrate this disconnect, Enbridge Gas has provided a comparison at Attachment 1 of the proposed ICM threshold value to the threshold value supported by rates assuming Enbridge Gas continued to pass-through the annual revenue requirement of the capital pass-through projects over the deferred rebasing period. The cumulative difference of $410 million represents the potential capital investment amount not supported by rates when changes in rate base are passed through to customers.

Changes to Deferral Accounts to Capture Utility Tax Timing Differences Only

The proposed one-time adjustment by itself does not support the level of capital investment assumed by the ICM threshold value because of the impact the utility tax timing differences have on the revenue requirement of the projects. Normal decreases in annual revenue requirement as a result of the annual decline in rate base are more than offset by increases to annual revenue requirement resulting from decreases in the utility tax timing benefits in each year of the deferred rebasing period. The ICM threshold value calculation does not consider the impact changes in utility tax timing differences has on funding incremental capital projects. The utility tax timing differences related to the capital pass-through projects create significant impacts to the revenue requirement that are not within the normal course of business because of the large addition to rate base over a short period of time and the differences in capital cost allowance and depreciation expense on the assets.

Enbridge Gas has proposed to change the capital pass-through deferral accounts to address the utility tax timing differences only to support the level of capital investments as assumed by the ICM threshold value calculation through the revenue requirement in rates of the projects. Enbridge Gas has proposed to continue to record the utility tax timing variance component of the revenue requirement in the deferral accounts because otherwise, over the deferred rebasing period, customers would receive a benefit of $57.9 million greater than the actual tax benefit that Enbridge Gas will receive over the same time period. In the absence of changing the deferral accounts as proposed, Enbridge Gas's rates cannot support the changes in utility tax timing differences or the required level of incremental capital investment prior to ICM funding.

b) Confirmed. The higher revenue requirement in rates during the deferred rebasing period as a result of the one-time adjustment is required to support the level of capital investment prior to ICM funding as discussed in part a). Please also refer to Exhibit I.SEC.6, Attachment 1.

c) Please see Attachment 2.

UNION RATE ZONES
Comparison of ICM Threshold Value Supported by Rates
As Proposed vs. Pass-through of Annual Revenue Requirement

Line No.	Particulars	As Proposed					Pass-through of Annual Revenue Requirement					Difference				
		As Filed 2019 (1)	2020	2021	2022	2023	2019	2020	2021	2022	2023	2019	2020	2021	2022	2023
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k) = (a-f)	(l) = (b-g)	(m) = (c-h)	(n) = (d-i)	(o) = (e-j)
1	Base Year	2013	2013	2013	2013	2013	2013	2013	2013	2013	2013	-	-	-	-	-
2	Number of Years since rebasing (n)	6	7	8	9	10	6	7	8	9	10	-	-	-	-	-
3	Price Cap Index (PCI) (%)	0.72%	0.72%	0.72%	0.72%	0.72%	0.72%	0.72%	0.72%	0.72%	0.72%	-	-	-	-	-
4	Growth Factor (g) (%)	1.19%	1.19%	1.19%	1.19%	1.19%	1.19%	1.19%	1.19%	1.19%	1.19%	-	-	-	-	-
5	Dead Band (%)	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	-	-	-	-	-
6	Rate Base (RB)	5,331	5,331	5,331	5,331	5,331	3,735	3,735	3,735	3,735	3,735	1,597	1,597	1,597	1,597	1,597
7	Depreciation (d)	239	239	239	239	239	196	196	196	196	196	43	43	43	43	43
8	ICM Threshold Value %	157.1%	158.0%	158.9%	159.9%	160.8%	150.2%	151.0%	151.7%	152.5%	153.4%	6.9%	7.1%	7.2%	7.3%	7.5%
9	ICM Threshold Value	375.2	377.3	379.5	381.8	384.1	294.5	296.0	297.5	299.1	300.7	80.7	81.3	82.0	82.7	83.3
10	Cumulative ICM Threshold Value	375.2	752.5	1,132.0	1,513.8	1,897.9	294.5	590.5	888.0	1,187.2	1,487.9	80.7	162.0	244.0	326.7	410.0

Notes:
(1) Exhibit B1, Tab 2, Schedule 1, Table 3.

UNION RATE ZONES
Summary of 2014-2023 Capital Pass-Through Revenue Requirement - Approved & Forecast
Included in Rates vs. Included in Deferrals

		Included in Rates			Included in Deferrals			Deferral Balance		
Line No.	Particulars ($000's)	Utility Timing Differences	Remaining Revenue Requirement (1)	Total Revenue Requirement	Utility Timing Differences	Remaining Revenue Requirement (1)	Total Revenue Requirement	Utility Timing Differences	Remaining Revenue Requirement (1)	Total Revenue Requirement
		(a)	(b)	(c) = (a+b)	(d)	(e)	(f) = (d+e)	(g) = (d-a)	(h) = (e-b)	(i) = (f-c)
	Approved									
1	2014	(1,618)	1,342	(276)	(2,191)	1,440	(751)	(573)	98	(475)
2	2015	(9,342)	15,638	6,296	(8,860)	15,067	6,207	482	(571)	(89)
3	2016	(24,919)	55,140	30,221	(22,665)	52,362	29,697	2,254	(2,778)	(524)
4	2017	(38,153)	114,931	76,778	(39,192)	109,603	70,411	(1,039)	(5,328)	(6,367)
5	2018 - Draft (2)	(46,020)	173,669	127,649	(42,442)	150,782	108,341	3,578	(22,887)	(19,309)
	Proposed									
6	2019 - Forecast	(36,415)	153,653	117,238	(36,415)	153,653	117,238	-	-	-
7	2020 - Forecast	(36,415)	153,653	117,238	(29,865)	153,653	123,787	6,549	-	6,549
8	2021 - Forecast	(36,415)	153,653	117,238	(24,051)	153,653	129,601	12,363	-	12,363
9	2022 - Forecast	(36,415)	153,653	117,238	(19,054)	153,653	134,598	17,360	-	17,360
10	2023 - Forecast	(36,415)	153,653	117,238	(14,752)	153,653	138,901	21,663	-	21,663

Notes:
(1) Panhandle Reinforcement project revenue requirement net of incremental project revenue.
(2) The 2018 revenue requirement included in rates as approved in EB-2017-0087. The final actual amounts included in deferrals will be filed as part of Enbridge Gas's 2018 Disposition of Deferral Account Balances proceeding.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Board Staff (STAFF)

Reference: Exhibit B1/Tab 1/Schedule 1/pg. 23

Question:

Enbridge Gas has proposed to close the Unbundled Services Unauthorized Storage Overrun Deferral Account (Account No. 179-103) effective January 1, 2019.

a) Please confirm that there is a $0 balance in the account as at December 31, 2018.
b) If not, please indicate the balance in the account and why the account should be closed at this time.

Response

Confirmed.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Board Staff (STAFF)

Reference: Exhibit F1/Tab 1/Rate Order Working Papers Schedule 10 and Exhibit F1/Tab 2/Rate Order Working Papers Schedule 13

Question:

The Rate Order Working Papers shows the change in average use for Enbridge Gas Distribution and the NAC for Union Gas. The average use has increased by 2.3% for Rate 1 customers of Enbridge Gas Distribution and by 1.7% for Rate 6 customers. Similarly, the NAC for Rates 01, 10, M1 and M2 customers of Union Gas has increased in the range of 3.0% to 4.8%.

Please confirm if there has been a gradual increase in the average use/NAC over the past three years in the Enbridge Gas Distribution and Union Gas rate zones.

Response

Not confirmed.

EGD Rate Zone

The 2.3% increase for Rate 1 customers and the 1.7% increase for Rate 6 customers of the EGD rate zone represent the percentage change from the 2018 Board Approved Budget to 2019 Forecast. It doesn't represent a change in actual average use. The 2018 Board Approved Budget was developed in an earlier proceeding using the actuals to 2016 and the assumptions from the 2017 Spring Economic Outlook while the 2019 forecast has been developed using the actuals to 2017 and the assumptions from 2018 Spring Economic Outlook. As a result, the 2.3% and 1.7% increase in Rate 1 and 6 average uses, respectively, is not reflective of the actual average use trend.

The following table illustrates actual average use changes for each rate class over the past 3 years. These figures have all been normalized to 2019 Budget degree days for comparability.

Historical AU for EGD Rate Zones, Calculated Using 2019 Budget Degree Days (m^3 per customer)

	2014	2015	2016	2017	2014-15	2015-16	2016-17	Average % Change
Rate 1	2,531	2,508	2,408	2,457	-0.9%	-4.0%	2.0%	-1.0%
Rate 6	29,299	29,661	28,340	29,102	1.2%	-4.5%	2.7%	-0.2%

Enbridge Gas does not believe that short term changes will represent the general trend in average use. However, Rate 1 average use per customer has declined at an average rate of 1.0% per year over the last 3 years while Rate 6 average use declined at an average rate of 0.2% in the same period. The Company's average use models rely on historical data and given the historical trend, in the absence of any other development that would reverse the trend, the expectation is that the declining trend for Rate 1 will continue.

Please refer to the response to Exhibit I.EP.5 for a graphical representation of the long-term average use trends.

Union Rate Zones

The percentage changes listed at Exhibit F1, Tab 2, Rate Order, Working Papers, Schedule 13 represent the actual NAC changes from 2016 to 2017, as well as an update from the 2018 Board-approved weather normal to the 2019 Board-approved weather normal for Union rate classes.

For comparability, the following table illustrates actual NAC changes for each rate class over the past 3 years, calculated using the 2019 weather normal.

Historical NAC for Union Rate Zones, Calculated Using 2019 Weather Normal (m^3 per customer)

	2014	2015	2016	2017	2014-15	2015-16	2016-17	Average % Change
Rate M1	2,840	2,741	2,685	2,767	-3.5%	-2.0%	3.0%	-0.8%
Rate M2	171,998	166,287	160,692	167,039	-3.3%	-3.4%	3.9%	-0.9%
Rate 01	3,013	2,861	2,815	2,853	-5.0%	-1.6%	1.4%	-1.8%
Rate 10	176,921	165,118	161,075	164,301	-6.7%	-2.4%	2.0%	-2.4%

For all Union rate classes, actual NAC decreased from 2014 to 2015 and from 2015 to 2016, and then increased from 2016 to 2017. Enbridge Gas does not believe that short term changes will represent the general NAC trend, and we are still seeing a long-term declining trend for all Union rate classes.

Please see Exhibit I.EP.5 for a graphical representation of the long-term NAC trends.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Board Staff (STAFF)

Reference: Exhibit B1/Tab 1/Schedule 1/pgs. 28-29

Question:

Enbridge Gas has proposed to build into rates the surplus Dawn-Parkway capacity of 30,393 GJ per day resulting from the 2017 Dawn-Parkway Expansion project. As part of the 2017 Dawn-Parkway proceeding, parties agreed that Union Gas would credit the Lobo D/Bright C/Dawn H Compressor Project Deferral Account (Account No, 179-144) for revenue generated from the 30,393 GJ per day of surplus capacity. Enbridge Gas anticipates that this surplus capacity will be sold long term beginning on November 1, 2018 and for the remainder of the deferred rebasing period. To account for the incremental project demands and revenue, Enbridge Gas has added 30,393 GJ per day of project demands to the allocation of the 2019 project costs. As revenue of the surplus capacity will be built into 2019 rates, there is no longer a requirement to track the revenue associated with the surplus capacity in the project deferral account.

a) Please confirm whether the surplus capacity has been sold long term as of November 1, 2018. If yes, please provide the total capacity sold, rate and the length of the term.
b) What is the impact on 2019 rates as a result of building into rates the surplus Dawn-Parkway capacity resulting from the 2017 Dawn-Parkway expansion project?
c) Does the revenue of the surplus capacity relate to the entire surplus capacity of 30,393 GJ per day or a portion of it? How does the revenue (rate per GJ) relate to other surplus capacity that Union Gas has sold in the past two years?
d) Has any of the 30,393 GJ per day of Dawn-Parkway surplus capacity been used to reduce the Parkway Delivery Obligation? If yes, please provide details.
e) Has the cost of the 30,393 GJ per day of surplus capacity been allocated to Union Gas customers in order to reduce the Parkway Delivery Obligation?
f) Enbridge Gas has indicated that the revenue of the surplus capacity is built into 2019 rates. Please provide the revenue that has been built into 2019 rates and the associated calculation to show that the revenue is an off-set to the 2019 proposed revenue requirement.

Response

a) Enbridge Gas sold 42,378 GJ/d of Dawn-Parkway capacity starting November 1, 2018 and ending October 31, 2040 at posted M12 rates. However, based on changes affecting the overall surplus since the time the original schedule was filed in 2015 (i.e., turnback, modelling changes, etc.), Enbridge Gas has surplus Dawn-Parkway capacity of approximately 126 TJ as of November 1, 2018. Enbridge Gas has sold additional long-term M12 contracts beginning November 1, 2019 which will completely utilize the surplus Dawn-Parkway capacity.

b) The 2019 Rate M12 demand charges have been reduced by the equivalent of the incremental $1.3 million in Rate M12 Dawn-Parkway revenue that has been sold long term.

c) The revenue of $1.3 million relates to the entire surplus capacity of 30,393 GJ/d (30,393 GJ/d x 12 x $3.586 GJ/m). The revenue is based on approved Rate M12 Dawn-Parkway demand charges, which is consistent with the sale of long-term Dawn-Parkway capacity sold over the past two years. The M12 rate is also comparable with the average price obtained for short-term and interruptible services sold over the past two years.

d) No. The 30,393 GJ/d of Dawn-Parkway surplus capacity was not used to reduce the Parkway Delivery Obligation. Please see part a).

e) No. Please see part d).

f) The forecast revenue associated with the 30,393 GJ/d is $1.3 million in 2019. To account for the incremental project revenue that has been sold long-term under Rate M12, Enbridge Gas has adjusted the Rate M12 billing units in the derivation of 2019 Rate M12 demand charges. This adjustment for the incremental project demands is consistent with the approved billing unit adjustments made in the 2017 Dawn-Parkway Project (EB-2015-0200) to account for the incremental project revenue.

   The inclusion of the 30,393 GJ/d of Rate M12 Dawn-Parkway demands in rates results in a decrease to the Rate M12 demand charges equivalent to the $1.3 million that Enbridge Gas will earn from the sale of 30,393 GJ/d based on the proposed 2019 Dawn-Parkway rate of $3.586 GJ/m (30,393 GJ/d x 12 x $3.586 GJ/m).

   Please see Attachment 1 for a reconciliation of the proposed 2019 Rate M12 demand charges including and excluding the 30,393 GJ/d to illustrate the revenue adjustment of $1.3 million that is included in 2019 proposed rates. The inclusion of the incremental demands in 2019 Rates results in lower Rate M12 demand charges that would have otherwise been higher had the excess capacity not been sold.

ENBRIDGE GAS INC.

Proposed Revenue Adjustment Associated with Incremental 30,393 GJ/d

Line No.	Particulars (1)	Annual Forecast Usage (GJ) (3)	Demand Charges ($/GJ/m)			Annual Revenue ($000's)		
			As Proposed (4)	Adjusted (5)	Variance	As Proposed (4)	Adjusted (5)	Variance
		(a)	(b)	(c)	(d) = (b - c)	(e) = (a x b / 1000)	(f) = (a x c / 1000)	(g) = (e - f)
	In Base Rates							
1	Dawn-Parkway	60,115,592	3.586	3.604	(0.019)	215,554	216,676	(1,122)
2	Dawn-Kirkwall	8,708,176	3.043	3.059	(0.016)	26,503	26,641	(138)
3	Kirkwall-Parkway	2,865,328	0.542	0.545	(0.003)	1,554	1,562	(8)
4	Westerly	9,023,655	0.844	0.849	(0.004)	7,620	7,660	(40)
						251,231	252,539	(1,308)
	Incremental Demands							
5	Dawn-Parkway (2)	364,716	3.586	-	3.586	1,308	-	1,308
6	Total in Base Rates	81,077,467				252,539	252,539	-
	Incremental Revenue Excluded from Base Rates							
7	Dawn-Parkway (2)	364,716	-	3.604	(3.604)	-	1,315	(1,315)
8	Deferral Account Adjustment (6)					-	(1,315)	1,315
9	Total Revenue					252,539	252,539	-

Notes:
(1) Rate M12 revenue requirement allocated to Rate M12 transportation paths using approved rate design methodologies.
(2) Annual forecast usage of 364,716 GJ calculated as 30,393 GJ/d x 12 months.
(3) Board-approved billing units updated to include incremental Dawn-Parkway demands of 30,393 GJ/d at line 5.
(4) Proposed demand charges and revenue including the incremental Dawn-Parkway demands of 30,393 GJ/d.
(5) Adjusted demand charges and revenue excluding the incremental Dawn-Parkway demands of 30,393 GJ/d.
(6) Incremental revenue excluded from base rates would be recorded and disposed of in the Dawn H/Lobo D/Bright C Compressor Project Costs Deferral Account (Account No. 179-144).

ENBRIDGE GAS INC.
Answer to Interrogatory from
Board Staff (STAFF)

Reference: Exhibit B1/Tab 1/Schedule 1/Pg. 29

Question:

Enbridge Gas has proposed to maintain the current level of the general service monthly customer charge for the Union Gas rate zone at $21 per month for Rate M1 and Rate 01 and $70 per month for Rate M2 and Rate 10.

Please provide the list of monthly customer charges that have been changed in the current application for Enbridge Gas Distribution and Union Gas rate zones.

Response

Please see Table 1 for the monthly customer charges that have a proposed change as part of the current application.

Table 1
Proposed Changes to the Monthly Customer Charge by Rate Class

Line No.	Particulars	Approved Monthly Customer Charge	Proposed Monthly Customer Charge
		(a)	(b)
	EGD		
1	Rate 9	$235.95	$238.47
2	Rate 100	$122.01	$123.32
	Union North		
3	Rate 20	$860.69	$918.21
4	Rate 25	$289.76	$317.47
5	Rate 100	$1,341.41	$1,409.84
	Union South		
6	Rate M4 – Interruptible	$644.34	$681.74
7	Rate M5	$644.34	$681.74
8	Rate T1	$1,896.28	$1,964.91
9	Rate T2	$5,440.88	$5,987.98
10	Rate T3		
11	City of Kitchener	$19,843.96	$20,640.21
12	Natural Resource Gas	$3,046.25	$3,168.48
13	Six Nations	$1,015.42	$1,056.16

The update to the monthly customer charges by rate class for each of the rate zones is generally consistent with the past practice used by legacy Union and legacy EGD during their previous IRM terms. The Union practice updates the monthly customer charge for contract rate classes. The EGD practice previously did not update the monthly customer charge for any rate class. As part of 2019 Rates, Enbridge Gas did update customer charges for Rate 9 and Rate 100 in the EGD rate zone for the Price Cap Index, however, there are no impacts associated with this update as there are no forecast customers that would take service under these rate classes.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Board Staff (STAFF)

Reference: Exhibit B1/Tab 1/Schedule 1/pgs. 29-31

Question:

In Table 11 (page 31) of the evidence, Enbridge Gas has provided a table that shows the impact of the proposed rate design changes for Union South M1 and Union North Rate 01 customers. The rate impact for a Union South M1 customer consuming 2,200 m^3 under the current approved rate design is 1.9% (Delivery bill impact) and under the proposed rate design it is 2.7%. Similarly, for a Union South M1 customer consuming 40,000 m^3, the rate impact changes from 5.2% to 1.3% using the proposed rate design.

a) Please provide the rate impact on a Union South M1 customer under the two consumption scenarios if the percentage rate impact for those consuming 2,200 m^3 and 40,000 m^3 is the same.
b) Please provide the percentage rate impact on a Union South M1 customer consuming 40,000 m^3 if the percentage rate impact for a customer consuming 2,200 m^3 is held to 2.2%.

Response

a) Please see Table 1. A delivery bill impact percentage of 2.4% creates the same bill impact percentage for a Union South Rate M1 customer consuming 2,200 m^3 and 40,000 m^3.

Table 1
Delivery Bill Impacts for Rate M1
Same Delivery Bill Impact Percentage

Line No.	Particulars ($)	Union South Rate M1 (a)	Union South Rate M1 (b)
1	Annual Consumption	2,200 m^3	40,000 m^3
2	Current Approved Delivery Bill	374	2,222
3	2019 Rates – Same Impact Percentage	383	2,276
4	Difference (line 3 - line 2)	9	54
5	Delivery Bill Impact (%) (line 4 / line 2)	2.4%	2.4%

b) Please see Table 2. A residential delivery bill impact percentage of 2.2% creates a 3.6% delivery bill impact percentage for a Union South Rate M1 customer consuming 40,000 m^3.

Table 2
Delivery Bill Impacts for Rate M1
2.2% Residential Delivery Bill Impact

Line No.	Particulars ($)	Union South Rate M1 (a)	Union South Rate M1 (b)
1	Annual Consumption	2,200 m^3	40,000 m^3
2	Approved Delivery Bill	374	2,222
3	2019 Rates – 2.2% Residential Impact	382	2,303
4	Difference (line 3 - line 2)	8	81
5	Delivery Bill Impact (%) (line 4 / line 2)	2.2%	3.6%

ENBRIDGE GAS INC.
Answer to Interrogatory from
Board Staff (STAFF)

Reference: Exhibit B1/Tab 1/Schedule 1/pgs. 31-33 and Exhibit F1/Tab 2/Working Papers/Schedule 11

Question:

Enbridge Gas has updated the Parkway Delivery Obligation and Parkway Delivery Commitment Incentive costs to reflect the 2019 Rate M12 Dawn-Parkway toll and Dawn-Parkway compressor fuel, based on Union Gas' October 2018 QRAM. The cost impact on the 2019 revenue requirement is $627,000. Schedule 11 of the Working Papers shows the total Parkway Delivery Obligation costs to be $24.723 million.

In the EB-2017-0087 Rate Order Working Papers (Schedule 20), the total Parkway Delivery Obligation costs for 2018 is $24.855 million. Please explain how the cost of $627,000 has been derived in relation to the 2018 amount shown in EB-2017-0087 and the $24.723 million for 2019.

Response

Please see Table 1 for a reconciliation between the $24.855 million PDO and PDCI costs as filed in the EB-2017-0087 application and the $24.723 million as filed in this application. The 2019 revenue requirement impact of $0.627 million is shown on line 6.

Table 1
PDO and PDCI Cost Reconciliation

Line No.	Particulars ($ millions)	Total PDO and PDCI Costs
1	2018 as filed in EB-2017-0087 draft rate order	24.855
2	2018 adjustment (1)	(0.253)
3	2018 as approved in EB-2017-0087 final rate order	24.602
4	2018 adjustment (2)	(0.507)
5	2018 as approved in EB-2018-0253 final rate order	24.095
6	2019 impact as proposed	0.627
7	2019 as filed in EB-2018-0305 draft rate order	24.723

Notes:

(1) PDCI costs adjusted in the EB-2017-0087 final rate order (Union’s 2018 Rates) to reflect an update to the Rate M12 Dawn to Parkway Cap-and-Trade Facility-Related Charge from $0.009/GJ to $0.006/GJ as approved in EB-2016-0296 (Union’s 2017 Cap-and-Trade Compliance Plan).

(2) PDCI costs updated in the EB-2018-0253 final rate order (Union’s October 2018 QRAM) to reflect the removal of the Rate M12 Dawn to Parkway Cap-and-Trade Facility-Related charge of $0.006/GJ.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Board Staff (STAFF)

Reference: Exhibit B1/Tab 1/Schedule 1/pgs.38-39

Question:

Enbridge Gas has proposed to change the Aid to Construction language in Union Gas' Rate M13 General Terms and Conditions (GT&C), effective January 1, 2019. The GT&C outlines the calculation of Aid to Construction payments associated with the capital cost of building a local producer station on Enbridge Gas' system rather than in the customer's contract or a separate precedent agreement. For consistency with other rate classes, Enbridge Gas proposes to move the specific Aid to Construction payment language from the GT&C to the customer's contract and replace it with the description used in the Union Gas Rate M16 GT&C.

a) What type of customers take service under Rate M13?
b) Is there a material difference in the language or the terms with respect to how Aid to Construction will be treated or calculated as a result of the proposed changes? If yes, please explain the changes in the terms.
c) How does Enbridge Gas propose to inform customers who have already contracted for service under Rate M13 of the changes noted above?

Response

a) The M13 rate schedule is applicable to customers located in the Union South rate zone who enter into a contract with Enbridge Gas for the transportation of natural gas produced within Ontario to Dawn.

b) No. There is no material difference in the language or the terms with respect to how Aid to Construction will be treated or calculated as a result of the changes.

c) The M13 General Terms and Conditions are posted on Union's website at https://www.uniongas.com/storage-and-transportation/informational-postings/tariffs. Changes to general terms and conditions are highlighted and posted with 60 days notice at this location with an associated effective date stated. This change will not impact existing M13 customers because the General Terms and Conditions that are in effect when the customer enters into contractual arrangements with Enbridge Gasremain in effect until the contract terminates.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Board Staff (STAFF)

Reference: Exhibit B1/Tab 1/Schedule 1/Appendices A and B

Question:

Enbridge Gas provided two draft accounting orders for each of the three new accounts: Accounting Policy Change Deferral Account (Appendix A, page 34 and Appendix B, page 35), Earnings Sharing Mechanism Deferral Account (Appendix A, page 35 and Appendix B, page 36) and the Tax Variance Deferral Account (Appendix A, page 36 and Appendix B, page 37).

Please explain why there are two draft accounting orders for each of the new accounts.

Response

Enbridge Gas provided two draft accounting orders for each of the three new accounts for the purposes of completeness, in order to show that each of the accounts is applicable to both the EGD and Union Gas rate zones. This was done solely for presentation, as Appendix A of Exhibit B1, Tab 1, Schedule 1 provided the accounting orders applicable to the EGD rate zone, while Appendix B provided the accounting orders applicable to the Union Gas zones. As seen in each appendix, the accounting orders for the three accounts are identical, and titled as Enbridge Gas Inc. accounting orders, while other accounting orders are titled as either EGD rate zone or Union Gas rate zones specific.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Board Staff (STAFF)

Reference: Exhibit B1/Tab 1/Schedule 1/pgs. 13, 17 and Appendices A and B

Question:

a) For the accounts listed in Table 5, where there have been adjustments to existing deferral and variance accounts, please provide a black lined version of the accounting orders showing the change from the original accounting order.

b) Page 13 states that the existing accounting orders have been updated to reflect the applicability of the account to the Enbridge Gas Distribution and Union Gas rate zones. For all existing accounts excluding those listed in Table 5, please confirm that the only change in the accounting orders was to update the naming of the specific rate zones under Enbridge Gas Inc. If not, please provide a black lined version of the accounting orders showing the change from the original accounting order and explain the need for the change.

Response

a) Please see Attachment 1 and Attachment 2 for the EGD and Union rate zones, respectively.

b) Confirmed.

DRAFT

ACCOUNTING TREATMENT FOR A
POST-RETIREMENT TRUE-UP VARIANCE ACCOUNT
("PTUVA") – ~~EGD~~EGD RATE ZONE

In accordance with the EB-2017-0086 Settlement Proposal, during 2018 the purpose of the Post-Retirement True-Up Variance Account (PTUVA) is~~will be~~ to record any allowed revenue impact that results from actual pension and OPEB related amounts (accrual based expense amounts and cash based funding) which differ compared to what was forecast and included in rates. This would include any allowed revenue impacts arising as a result of ~~proposed~~ changes to Ontario pension legislation and regulations which proceed. The PTUVA will be cleared subject to the condition that any allowed revenue variance in excess of $5 million (credit or debit) will remain in the account, so that large variances can be cleared over time (smoothed). Under this approach, the maximum amount (debit or credit) that will be cleared from the PTUVA will be $5 million with any balance to remain in the account for future clearance. In accordance with the EB-2017-0306/EB-2017-0307 Decision and Order, beginning in 2019 the PTUVA will only be utilized to reflect any residual balance from 2018 that has not been cleared due to the smoothing mechanism related to the account.

Simple interest is to be calculated on the opening monthly balance of this account using the Board approved EB-2006-0117 interest rate methodology. The balance of this account, together with carrying charges, will be disposed of in a manner designated by the Board in a future rate hearing.

Accounting Entries

1. To record the pension and post-employment benefit allowed revenue true-up amounts:

Debit:	PTUVA	(Account 179. 24_)
Credit:	Accounts payable	(Account 251. 010)
	Or	
Debit/Credit:	Operating revenue	(Account 300.000)
Credit/Debit:	PTUVA	(Account 179.24_)

To record the allowed revenue impact resulting from variances between actual pension and post-employment benefits, versus amounts embedded in rates.

2. Interest accrual:

Debit/Credit:	Interest on PTUVA	(Account 179. 25_)
Credit/Debit:	Interest expense	(Account 323. 000)

To record simple interest on the opening monthly balance of the PTUVA using the Board approved EB-2006-0117 interest rate methodology.

DRAFT

ACCOUNTING TREATMENT FOR AN
OPEN BILL REVENUE VARIANCE ACCOUNT
("OBRVA") – ~~EGD~~EGD RATE ZONE

The purpose of the OBRVA is to track and record the ratepayer share of net revenue for Open Bill Services. The account allows for net annual revenue amounts in excess of $7.389 million to be shared 50/50 with ratepayers, and allows for a credit to the Company~~Enbridge~~ in the event that net annual revenues are less than $4.889 million, equal to the shortfall between actual net revenues and $4.889 million. The net revenue amounts will be determined in accordance with the EB-~~2009~~2013-00~~9943~~ Board ~~A~~approved Open Bill Access Settlement Proposal~~ dated October 15, 2009~~, as amended and approved by the Board from time to time~~with updated Fees and Costs as determined in the EB-2013-0099 proceeding~~.

Simple interest is to be calculated on the opening monthly balance of this account using the Board approved EB-2006-0117 interest rate methodology. The balance of this account, together with carrying charges, will be disposed of in a manner designated by the Board in a future rate hearing.

Accounting Entries

1. To track and record Open Bill services net revenue:

Debit:	Other income	(Account 319. 010)
Credit:	OBRVA	(Account 179. 48_)
	Or	
Debit:	OBRVA	(Account 179. 48_)
Credit:	Operating revenue	(Account 300. 000)

To record the variance in the ratepayer porting of net revenue associated with Open Bill Service programs in excess of $7.389 million or below $4.889 million.

2. Interest accrual:

Debit/Credit:	Interest on OBRVA	(Account 179. 49_)
Credit/Debit:	Interest expense	(Account 323. 000)

To record simple interest on the opening monthly balance of the OBRVA using the Board approved EB-2006-0117 interest rate methodology.

DRAFT

ACCOUNTING TREATMENT FOR AN
EX-FRANCHISE THIRD PARTY BILLING SERVICES DEFERRAL ACCOUNT
("EFTPBSDA") – ~~EGD~~EGD RATE ZONE

The purpose of the EFTPBSDA is to record and track the ratepayer portion of revenues, net of incremental costs, generated from third party billing services provided to ex-franchise parties. The net revenue is to be shared on a 50/50 basis with ratepayers. The net revenue amounts will be determined in accordance with the EB-~~2009~~2013-~~0043~~ 0099 Board ~~A~~approved Open Bill Access Settlement Proposal, ~~dated October 15, 2009, with updated Fees and Costs as determined in the EB-2013-0099 proceeding.~~as amended and approved by the Board from time to time.

Simple interest is to be calculated on the opening monthly balance of this account using the Board approved EB-2006-0117 interest rate methodology. The balance of this account, together with carrying charges, will be disposed of in a manner designated by the Board in a future rate hearing.

Accounting Entries

1. To track and record the ratepayer portion of net revenue:

Debit/Credit:	EFTPBSDA	(Account 179. 08_)
Credit/Debit:	Various accounts	(Account ___. ___)

To record net revenue associated with Ex-Franchise third party Billing Services.

2. Interest accrual:

Debit/Credit:	Interest on EFTPBSDA	(Account 179. 09_)
Credit/Debit:	Interest expense	(Account 323. 000)

To record simple interest on the opening monthly balance of the EFTPBSDA using the Board approved EB-2006-0117 interest rate methodology.

DRAFT

ACCOUNTING TREATMENT FOR A
PURCHASED GAS VARIANCE ACCOUNT
("PGVA") – ~~EGD~~EGD RATE ZONE

The purpose of the PGVA is to record the effect of price variances between actual gas purchase prices and the forecast prices that underpin the revenue for rates to be charged throughout the fiscal year. Without this deferral account, the ratepayers and the Company are exposed to the risk of purchased gas price variances, which could unduly penalize or benefit one party at the benefit or expense of the other. Lower than forecast gas purchase prices would result in an over recovery from the customers and higher prices would result in an under recovery to the Company. This deferral account ensures that such effects are eliminated.

Methodology

The actual unit cost is determined by dividing the total commodity and transportation costs (less the demand charges related to unutilized TransCanada firm service transportation capacity, if any) plus any other costs associated with emerging gas pricing mechanisms incurred in the month by the actual volumes purchased in the month. The rate differential between the PGVA reference price and the actual unit cost of the purchases, multiplied by the actual volumes purchased, is recorded in the PGVA monthly.

The fixed cost component of the TransCanada firm service transportation costs (i.e., Transportation Demand Charge) is included in the determination of the reference price. However, any demand charges relating to unutilized transportation capacity, either forecast or actual, are excluded. This treatment of forecast and actual Transportation Demand Charges for unutilized transportation capacity is consistent with the Board's concerns that these amounts be excluded from the PGVA.

Since all transportation costs on volumes purchased by the Company related to forecast utilized capacity are included in the determination of the PGVA reference price, any changes in the TransCanada tolls will be recorded in the PGVA. Any toll changes related to the cost of forecast unutilized capacity will not be recorded in the PGVA and therefore, requires separate adjustment. The inclusion of changes in TransCanada tolls in the PGVA is consistent with past practice.

Since the transportation tolls for other transportation services, such as for the Vector, Link, and NEXUS pipelines, that were used in the determination of the PGVA reference price were based upon an estimate, any variation between the actual transportation costs (including associated fuel costs) and the estimated transportation costs will be recorded in the PGVA.

Since transportation costs related to the transport of Western Canada Bundled T-service volumes are not included in the derivation of the PGVA reference price, changes in TransCanada tolls will be recorded in the PGVA as a separate adjustment.

Throughout the fiscal year expenditures related to TransCanada's Storage Transportation Services, including balancing fees related to TransCanada's Limited Balancing Agreement, will be recorded in the PGVA. ~~The PGVA will also record amounts related to a Limited Balancing Agreement with Union Gas.~~

The PGVA will record adjustments related to transactional services activities which are designed to record the impact of direct and avoided costs between the PGVA and the TSDA. These adjustments are required to ensure appropriate allocation of costs and benefits to the underlying transactions and appropriate recording of amounts in the PGVA and TSDA for purposes of deferral account dispositions.

In addition, the PGVA will record the amounts related to unforecast penalty revenues received from interruptible customers who do not comply with the Company's curtailment requirements, unauthorized overrun gas revenues, the use of electronic bulletin boards, and the unforecast Unabsorbed Demand Charge ("UDC") that arises as a consequence of the Company voluntarily leaving transportation capacity unutilized in order to gain a net benefit for the customer by purchasing lower priced unforecast discretionary delivered supplies.

The PGVA will also record an inventory valuation adjustment every time a recalculated “Utility Price” or PGVA Reference Price comes into effect at the beginning of a quarter. The adjustment consists of the storage inventory valuation adjustment necessary to price actual opening inventory volumes at a rate equal to the Board approved quarterly PGVA reference price.

The PGVA will also record any refund/collection associated with Board approved Gas Cost Adjustment Riders.

The Company will record, at the time a Banked Gas Account Balance is purchased from a customer, the difference in the amount payable to the customer and the amount included in the PGVA (Transportation Service Rider A). This amount would be credited to a sub-account of the PGVA. In the event the Company incurs unforecast UDC costs as a result of having to purchase Banked Gas Account Balances then the amount in such sub-account will be used to offset corresponding UDC costs. All amounts remaining in this sub-account, after offsetting these UDC costs, will be rolled up into the PGVA.

The commodity sale price on the disposition of Banked Gas Account Balances, the incentive sale price, is set at 120% of an average Empress price over the 12 months of the contractual year. Any amount in excess of 100% of the gas supply charge stated in the applicable rate schedule, net of the commodity related bad debt, will be included in the PGVA for each fiscal year.

Simple interest is to be calculated on the opening monthly balance of the PGVA using the Board Approved EB-2006-0117 interest rate methodology. The balance of the PGVA, together with carrying charges, will be disposed of in a manner designated by the Board in a future rate hearing.

Accounting Entries

1. To record the monthly gas purchase variance:

Debit:	PGVA	(Account 179. 70_)
Credit:	Gas in Storage	(Account 152. 000)
	or	
Debit:	Gas in Storage	(Account 152. 000)
Credit:	PGVA	(Account 179.70_)

To record the total rate variance on the current month's gas purchases.

2. TransCanada Toll changes related to forecast unutilized transportation capacity:

Debit:	PGVA	(Account 179. 70_)
Credit:	Accounts Payable	(Account 259. 000)
	or	
Debit:	Gas in Storage	(Account 152. 000)
Credit:	PGVA	(Account 179. 70_)

To record the amounts related to TransCanada toll changes on forecast unutilized transportation capacity.

3. TransCanada Toll changes related to Western Canada Bundled T-Service transportation capacity:

Debit:	PGVA	(Account 179. 70_)
Credit:	Accounts Payable	(Account 259. 000)
	or	
Debit:	Gas in Storage	(Account 152. 000)
Credit:	PGVA	(Account 179. 70_)

To record the amounts related to TransCanada toll changes on Western Canada Bundled T-Service transportation capacity.

4. Transactional services activities:

Debit/Credit:	TSDA	(Account 179. 80_)
Debit/Credit:	Various accounts	(Account ___. ___)
Credit/Debit:	PGVA	(Account 179. 70_)

To record adjustments for direct and avoided costs related to Transactional Services activities between the PGVA and TSDA, and other accounts such as Gas Costs, Gas Stored Underground and Storage Demand Charges.

5. Electronic bulletin boards:

Debit:	PGVA	(Account 179. 70_)
Credit:	Accounts Payable	(Account 259. 000)

To record the amounts related to the Company's use of electronic bulletin boards.

6. Unforecast penalty revenues:

Debit:	Accounts Receivable	(Account 140. 010)
Credit:	PGVA	(Account 179. 70_)

To record unforecast penalty revenues received from interruptible customers who do not comply with the Company's curtailment requirements.

7. Voluntary UDC:

Debit:	PGVA	(Account 179. 70_)
Credit:	Accounts Payable	(Account 259. 000)

To record voluntary UDC as a result of purchasing lower priced unforecast discretionary delivered supplies.

8. Inventory valuation adjustment:

Credit/Debit:	Gas In Storage	(Account 152. 000)
Debit/Credit:	PGVA	(Account 179. 70_)

To record the adjustment necessary to value actual inventory volumes at a rate equal to the PGVA reference price.

9. Refund or collection of the Gas Cost Adjustment Rider:

Debit/Credit:	PGVA	(Account 179. 70_)
Credit/Debit:	Accounts Receivable	(Account 140. 010)

To record the amounts refunded or collected from customers through the Gas Cost Adjustment Rider.

10. Purchase of banked gas account balance:

Debit:	Gas In Storage	(Account 152. 000)
Credit:	PGVA	(Account 179. 70_)

To record the purchase of the Banked Gas Account Balance less the Transportation Service Rider A.

11. Unforecast UDC:

Debit:	PGVA	(Account 179. 70_)
Credit:	Accounts Payable	(Account 259. 000)

To record unforecast UDC costs resulting from the purchase of Banked Gas Account Balances from T-Service customers.

12. Sales in excess of 100% of the applicable gas supply charge:

Debit:	Other Income	(Account 319. 010)
Credit:	PGVA	(Account 179. 70_)

To record the amount of sales in excess of 100% of the gas supply charge stated in the applicable rate schedule, net of the commodity related bad debt amount.

13. Interest accrual:

Debit:	PGVA - Interest Receivable	(Account 179. 71_)
Credit:	Interest Expense	(Account 323. 000)
	or	
Debit:	Interest Expense	(Account 323. 000)
Credit:	PGVA - Interest Payable	(Account 179. 71_)

To record simple interest on the opening monthly balance of the PGVA using the Board ~~A~~approved EB-2006-0117 interest rate methodology.

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ACCOUNTING TREATMENT FOR A
STORAGE AND TRANSPORTATION DEFERRAL ACCOUNT
("S&TDA") – ~~EGD~~EGD RATE ZONE

The purpose of the S&TDA is to record the difference between the forecast of Storage and Transportation rates (both cost of service and market based pricing) included in the Company's approved rates and the final Storage and Transportation rates (both cost of service and market based pricing) incurred by the ~~c~~Company. It will also be used to record variances between the forecast Storage and Transportation rebate programs and the final rebates received by the ~~c~~Company. ~~The accounting treatment for the S&TDA is in line with that established for the 2008 S&TDA, which recognized that storage and transportation services may be provided to the Company by suppliers other than Union Gas and at market based rates.~~

The S&TDA will also record the variance between the forecast Storage and Transportation demand levels and the actual Storage and Transportation demand levels. In addition, this account will be used to record amounts related to deferral account dispositions received or invoiced from Storage and Transportation suppliers.

The S&TDA will also record the variance between the forecasted commodity cost for fuel and the updated QRAM Reference Price.

Simple interest is to be calculated on the opening monthly balance of the S&TDA using the Board Approved EB-2006-0117 interest rate methodology. The balance of this account, together with carrying charges, will be disposed of in a manner designated by the Board in a future rate hearing.

Accounting Entries

1. Storage and Transportation rate variance:

[(Final Storage and Transportation rates) – (Storage and Transportation rates underpinning the Company's rates)] X Actual storage and/or transportation volumes

Debit/Credit:	S&TDA	(Account 179. 88_)
Credit/Debit:	Gas in Storage	(Account 152. 000)
	or	
Credit/Debit:	Gas Costs	(Account 623. 010)

To record the difference between the Storage and Transportation rates included in the Company's rates and the final Storage and Transportation rates.

2. To record variances in the Storage and Transportation rebate programs:

Debit:	Sundry Accounts Receivable	(Account 141. 030)
Credit:	S&TDA	(Account 179. 88_)
	or	
Debit:	S&TDA	(Account 179. 88_)
Credit:	Accounts Payable	(Account 259. 000)

To record the difference between the Storage and Transportation rebate programs included in the Company's rates and the final rebates received by the Company.

3. To record Storage and Transportation deferral account dispositions:

Debit:	Sundry Accounts Receivable	(Account 141. 030)
Credit:	S&TDA	(Account 179. 88_)
	or	
Debit:	S&TDA	(Account 179. 88_)
Credit:	Accounts Payable	(Account 259. 000)

To record amounts related to deferral account dispositions received or invoiced from Storage and Transportation.

4. Inventory valuation adjustment:

Debit/Credit:	S&TDA	(Account 179. 88_)
Credit/Debit:	Gas In Storage	(Account 152. 000)

To record adjustments to storage and transmission fuel costs associated with quarterly price changes.

5. Interest accrual:

Debit/Credit:	Interest on S&TDA	(Account 179. 89_)
Credit/Debit:	Interest Expense	(Account 323. 000)

To record simple interest on the opening monthly balance of the S&TDA using the Board ~~A~~approved EB-2006-0117 interest rate methodology.

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ACCOUNTING TREATMENT FOR AN
OEB COST ASSESSMENT VARIANCE ACCOUNT
("OEBCAVA") – ~~EGD~~EGD RATE ZONE

As authorized in the OEB's letter to all regulated entities, dated February 9, 2016, titled "*Revisions to the Ontario Energy Board Cost Assessment Model*", the purpose of the OEBCAVA will be to record any variance between the OEB costs assessed to Enbridge under the prior cost assessment model (prior to April 1, 2016), which are included in rates, and the OEB costs assessed to Enbridge under the new OEB cost assessment model (effective April 1, 2016). Entries into the variance account will be made on a quarterly basis when the OEB's cost assessment invoice is received. The account is subject to a $1 million materiality threshold.

Simple interest is to be calculated on the opening monthly balance of this account using the Board ~~A~~approved EB-2006-0117 interest rate methodology. The balance in this account, together with carrying charges, will be disposed of in a manner designated by the Board in a future rate hearing.

Accounting Entries

1. To record the variance in OEB costs:

Debit:	OEBCAVA	(Account 179. 94_)
Credit:	Accounts Payable	(Account 251. 010)

To record the variance in OEB costs assessed under the updated cost assessment model and the costs assessed under the prior cost assessment model.

2. Interest accrual:

Debit:	Interest on OEBCAVA	(Account 179. 95_)
Credit:	Interest expense	(Account 323. 000)

To record simple interest on the opening monthly balance of the OEBCAVA using the Board approved EB-2006-0117 interest rate methodology.

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UNION ~~GAS LIMITED~~RATE ZONES

Accounting Entries for
Parkway West Project Costs
Deferral Account No. 179-136

Account numbers are from the Uniform System of Accounts for Gas Utilities, Class A prescribed under the Ontario Energy Board Act.

Debit	-	Account No.179-136 Other Deferred Charges – Parkway West Project Costs
Credit	-	Account No. 579 Miscellaneous Operating Revenue

To record, as a debit (credit) in Deferral Account No. 179-136, the utility tax timing amounts ~~Union~~for the Parkway West Project as compared to the utility tax timing amounts~~the difference between the actual revenue requirement related to the costs for the Parkway West Project and the revenue requirement~~ included in rates as approved by the Board.

Debit	-	Account No.179-136 Other Deferred Charges – Parkway West Project Costs
Credit	-	Account No. 323 Other Interest Expense

To record, as a debit (credit) in Deferral Account No. 179-136, interest on the balance in Deferral Account No. 179-136. Simple interest will be computed monthly on the opening balance in the said account in accordance with the methodology approved by the Board in EB-2006-0117.

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UNION ~~GAS LIMITED~~RATE ZONES

Accounting Entries for
Brantford-Kirkwall/Parkway D Project Costs
Deferral Account No. 179-137

Account numbers are from the Uniform System of Accounts for Gas Utilities, Class A prescribed under the Ontario Energy Board Act.

Debit	-	Account No.179-137 Other Deferred Charges – Brantford-Kirkwall/Parkway D Project Costs
Credit	-	Account No. 579 Miscellaneous Operating Revenue

To record, as a debit (credit) in Deferral Account No. 179-137, the utility tax timing amounts for the Brantford-Kirkwall/Parkway D Project as compared to the utility tax timing amounts~~the difference between the actual revenue requirement related to the costs for the Brantford-Kirkwall/Parkway D Project and the revenue requirement~~ included in rates as approved by the Board.

Debit	-	Account No.179-137 Other Deferred Charges – Brantford-Kirkwall/Parkway D Project Costs
Credit	-	Account No. 323 Other Interest Expense

To record, as a debit (credit) in Deferral Account No. 179-137, interest on the balance in Deferral Account No. 179-137. Simple interest will be computed monthly on the opening balance in the said account in accordance with the methodology approved by the Board in EB-2006-0117.

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UNION ~~GAS LIMITED~~RATE ZONES

Accounting Entries for
Lobo C Compressor/Hamilton-Milton Pipeline Project Costs
Deferral Account No. 179-142

Account numbers are from the Uniform System of Accounts for Gas Utilities, Class A prescribed under the Ontario Energy Board Act.

Debit	-	Account No.179-142 Other Deferred Charges – Lobo C Compressor/Hamilton-Milton Pipeline Project Costs
Credit	-	Account No. 579 Miscellaneous Operating Revenue

To record, as a debit (credit) in Deferral Account No. 179-142, the utility tax timing amounts for the Lobo C Compressor/Hamilton Milton Pipeline Project as compared to the utility tax timing amounts~~the difference between the actual revenue requirement related to the costs for the Lobo C Compressor/Hamilton-Milton Pipeline Project and the revenue requirement~~ included in rates as approved by the Board.

Debit	-	Account No.179-142 Other Deferred Charges – Lobo C Compressor/Hamilton-Milton Pipeline Project Costs
Credit	-	Account No. 323 Other Interest Expense

To record, as a debit (credit) in Deferral Account No. 179-142, interest on the balance in Deferral Account No. 179-142. Simple interest will be computed monthly on the opening balance in the said account in accordance with the methodology approved by the Board in EB-2006-0117.

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UNION ~~GAS LIMITED~~RATE ZONES

Accounting Entries for
Lobo D/Bright C/Dawn H Compressor Project Costs
Deferral Account No. 179-144

Account numbers are from the Uniform System of Accounts for Gas Utilities, Class A prescribed under the Ontario Energy Board Act.

Debit	-	Account No.179-144 Other Deferred Charges – Lobo D/Bright C/Dawn H Compressor Project Costs
Credit	-	Account No. 579 Miscellaneous Operating Revenue

To record, as a debit (credit) in Deferral Account No. 179-144, the utility tax timing amounts for the Lobo D/Bright C/Dawn H Compressor Project as compared to the utility tax timing amounts~~the difference between the actual revenue requirement related to the costs for the Lobo D/Bright C/Dawn H Compressor Project and the revenue requirement~~ included in rates as approved by the Board.

Debit	-	Account No.179-144 Other Deferred Charges – Lobo D/Bright C/Dawn H Compressor Project Costs
Credit	-	Account No. 323 Other Interest Expense

To record, as a debit (credit) in Deferral Account No. 179-144, interest on the balance in Deferral Account No. 179-144. Simple interest will be computed monthly on the opening balance in the said account in accordance with the methodology approved by the Board in EB-2006-0117.

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UNION ~~GAS LIMITED~~RATE ZONES

Accounting Entries for
Burlington-Oakville Project Costs
Deferral Account No. 179-149

Account numbers are from the Uniform System of Accounts for Gas Utilities, Class A prescribed under the Ontario Energy Board Act.

Debit	-	Account No.179-149 Other Deferred Charges – Burlington-Oakville Project Costs
Credit	-	Account No. 579 Miscellaneous Operating Revenue

To record, as a debit (credit) in Deferral Account No. 179-149, the utility tax timing amounts for the Burlington-Oakville Project as compared to the utility tax timing amounts~~the difference between the actual revenue requirement related to the costs for the Burlington-Oakville Project and the revenue requirement~~ included in rates as approved by the Board.

Debit	-	Account No.179-149 Other Deferred Charges – Burlington-Oakville Project Costs
Credit	-	Account No. 323 Other Interest Expense

To record, as a debit (credit) in Deferral Account No. 179-149, interest on the balance in Deferral Account No. 179-149. Simple interest will be computed monthly on the opening balance in the said account in accordance with the methodology approved by the Board in EB-2006-0117.

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UNION ~~GAS LIMITED~~RATE ZONES

Accounting Entries for
Panhandle Reinforcement Project Costs
Deferral Account No. 179-156

Account numbers are from the Uniform System of Accounts for Gas Utilities, Class A prescribed under the Ontario Energy Board Act.

Debit	-	Account No.179-156 Other Deferred Charges – Panhandle Reinforcement Project Costs
Credit	-	Account No. 579 Miscellaneous Operating Revenue

To record, as a debit (credit) in Deferral Account No. 179-156, the utility tax timing amounts for the Panhandle Reinforcement Project as compared to the utility tax timing amounts~~the difference between the actual net delivery revenue requirement related to the costs for the Panhandle Reinforcement Project and the net delivery revenue requirement~~ included in rates as approved by the Board.

Debit	-	Account No.179-156 Other Deferred Charges – Panhandle Reinforcement Project Costs
Credit	-	Account No. 323 Other Interest Expense

To record, as a debit (credit) in Deferral Account No. 179-156, interest on the balance in Deferral Account No. 179-156. Simple interest will be computed monthly on the opening balance in the said account in accordance with the methodology approved by the Board in EB-2006-0117.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Board Staff (STAFF)

Reference: Exhibit B1/Tab 1/Schedule 1/Appendices A and B

Question:

For some variance accounts, the accounts capture the difference between actual revenues/costs and the reference amount, which is the revenues/costs approved in rates. During the deferred rebasing period, specific revenues/costs in the revenue requirement are not forecasted each year, but adjusted by a price cap index instead.

a) Please identify all accounts where the reference amount would be adjusted by the price cap index.
b) For these accounts, please explain how Enbridge Gas proposes to determine the reference amount of the revenues/costs approved in rates. Please explain Enbridge Gas' rationale.

Response

a) Enbridge Gas is not proposing to adjust any of the EGD or Union rate zone deferral account reference amounts by the price cap index. This is consistent with the treatment of deferral reference amounts for both EGD and Union during prior IR terms.

b) See the response to a) above.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Board Staff (STAFF)

Reference: Exhibit B1/Tab 1/Schedule 1/Appendix A/pgs. 33-36 and Appendix B/pg.34-37

Question:

For the accounting orders of the new accounts, please revise the accounting orders to include a description of the background of the account, similar to the accounting orders provided for the Enbridge Gas Distribution rate zone (pages 1-32).

Response

Please see Attachment 1 for the revised accounting orders.

DRAFT

UNION RATE ZONES

Accounting Entries for
Incremental Capital Module (ICM) Deferral Account
Deferral Account No. 179-XXX

The purpose of the Union Rate Zones ICM deferral account is to record the difference between the actual revenue requirement for the Union Rate Zones approved ICM projects, and the actual revenues collected through ICM rates approved by the Board for the Union Rate Zones. The actual revenue requirement will include costs associated with the capital investment, including return on rate base, depreciation expense, and associated income taxes, as well as material incremental operating expenses (O&M and property taxes), if applicable. The actual revenues will be those collected through the ICM rate riders approved by the Board for the Union Rate Zones.

Simple interest is to be calculated on the opening monthly balance of this account using the Board-approved EB-2006-0117 interest rate methodology. The balance of this account, together with carrying charges, will be disposed of in a manner designated by the Board in a future rate hearing.

Account numbers are from the Uniform System of Accounts for Gas Utilities, Class A prescribed under the Ontario Energy Board Act.

Debit	-	Account No.179- XXX Other Deferred Charges – Union Rate Zones – ICM Deferral Account
Credit	-	Account No. 579 Miscellaneous Operating Revenue

To record, as a debit (credit) in Deferral Account No. 179-XXX, the difference between the actual revenue requirement for approved ICM Projects and the actual revenues collected through ICM rates approved by the Board.

Debit	-	Account No.179-XXX Other Deferred Charges – Union Rate Zones – ICM Deferral Account
Credit	-	Account No. 323 Other Interest Expense

To record, as a debit (credit) in Deferral Account No. 179-XXX, interest on the balance in Deferral Account No. 179-XXX. Simple interest will be computed monthly on the opening balance in the said account in accordance with the methodology approved by the Board in EB-2006-0117.

DRAFT

EGD RATE ZONE

Accounting Entries for
Incremental Capital Module (ICM) Deferral Account
Deferral Account No. 179-XXX

The purpose of the EGD Rate Zone ICM deferral account is to record the difference between the actual revenue requirement for the EGD Rate Zone approved ICM projects, and the actual revenues collected through ICM rates approved by the Board for the EGD Rate Zone. The actual revenue requirement will include costs associated with the capital investment, including return on rate base, depreciation expense, and associated income taxes, as well as material incremental operating expenses (O&M and property taxes), if applicable. The actual revenues will be those collected through the ICM rate riders approved by the Board for the EGD Rate Zone.

Simple interest is to be calculated on the opening monthly balance of this account using the Board-approved EB-2006-0117 interest rate methodology. The balance of this account, together with carrying charges, will be disposed of in a manner designated by the Board in a future rate hearing.

Account numbers are from the Uniform System of Accounts for Gas Utilities, Class A prescribed under the Ontario Energy Board Act.

Debit	-	Account No.179- XXX Other Deferred Charges – EGD Rate Zone – ICM Deferral Account
Credit	-	Account No. 579 Miscellaneous Operating Revenue

To record, as a debit (credit) in Deferral Account No. 179-XXX, the difference between the actual revenue requirement for approved ICM Projects and the actual revenues collected through ICM rates approved by the Board.

Debit	-	Account No.179-XXX Other Deferred Charges – EGD Rate Zone – ICM Deferral Account
Credit	-	Account No. 323 Other Interest Expense

To record, as a debit (credit) in Deferral Account No. 179-XXX, interest on the balance in Deferral Account No. 179-XXX. Simple interest will be computed monthly on the opening balance in the said account in accordance with the methodology approved by the Board in EB-2006-0117.

DRAFT

ENBRIDGE GAS INC.

Accounting Entries for
Accounting Policy Changes
Deferral Account No. 179-XXX

The purpose of the Accounting Policy Changes deferral account, as established in the Board's EB-2017-0306/EB-2017-0307 Decision and Order, is to record the impact of any accounting changes that affect revenue requirement, which are required as a result of the amalgamation of Enbridge Gas Distribution and Union Gas Limited into Enbridge Gas Inc.

Simple interest is to be calculated on the opening monthly balance of this account using the Board-approved EB-2006-0117 interest rate methodology. The balance of this account, together with carrying charges, will be disposed of in a manner designated by the Board in a future rate hearing.

Account numbers are from the Uniform System of Accounts for Gas Utilities, Class A prescribed under the Ontario Energy Board Act.

Debit	-	Account No. 179-XXX Accounting Policy Changes
Credit	-	Account No. 300 Operating Revenues

To record as a debit (credit) in Deferral Account No. 179-XXX the impact of any accounting changes required as a result of the amalgamation that affect revenue requirement.

Debit	-	Account No. 179-XXX Accounting Policy Changes
Credit	-	Account No. 323 Other Interest Expense

To record, as a debit (credit) in Deferral Account No. 179-XXX, interest on the balance in Deferral Account No. 179-XXX. Simple interest will be computed monthly on the opening balance in the said account in accordance with the methodology approved by the Board in EB-2006-0117.

DRAFT

ENBRIDGE GAS INC.

Accounting Entries for
Earnings Sharing Mechanism Deferral Account
Deferral Account No. 179-XXX

The purpose of the Earnings Sharing Mechanism Deferral Account ("ESMDA") is to record the ratepayer share of utility earnings that result from the application of the earnings sharing mechanism. In accordance with the EB-2017-0306/EB-2017-0307 Decision and Order, if the actual utility return on equity (ROE) exceeds the Board-approved ROE by more than 150 basis points, the excess earnings will be shared equally (i.e. 50/50) between the Company's ratepayers and shareholders. The calculation of a utility return for earnings sharing determination purposes, will include all revenues that would otherwise be included in earnings and only those expenses (whether operating or capital) that would otherwise be allowable deductions from earnings as within a cost of service application.

Simple interest is to be calculated on the opening monthly balance of this account using the Board approved EB-2006-0117 interest rate methodology. The balance of this account, together with carrying charges, will be disposed of in a manner designated by the Board in a future rate hearing.

Account numbers are from the Uniform System of Accounts for Gas Utilities, Class A prescribed under the Ontario Energy Board Act.

Debit	-	Account No. 300 Operating Revenue
Credit	-	Account No. 179-XXX Earnings Sharing Mechanism Deferral Account

To record as a credit in Deferral Account No. 179-XXX the ratepayers' 50% share of utility earnings when actual utility ROE exceeds the Board-approved ROE by more than 150 basis points in accordance with the Board's Decision in EB-2017-0306/EB-2017-0307.

Debit	-	Account No. 323 Other Interest Expense
Credit	-	Account No. 179-XXX Earnings Sharing Mechanism Deferral Account

To record, as a credit in Deferral Account No. 179-XXX, interest on the balance in Deferral Account No. 179-XXX. Simple interest will be computed monthly on the opening balance in the said account in accordance with the methodology approved by the Board in EB-2006-0117.

DRAFT

ENBRIDGE GAS INC.

Accounting Entries for
Tax Variance Deferral Account
Deferral Account No. 179-XXX

The purpose of the Tax Variance Deferral Account is to record 50% of the variance in costs of any tax rate changes, versus the tax rates included in rates that affect Enbridge Gas Inc. As part of the EB-2017-0306/EB-2017-0307 Decision and Order, the Board amended the former Union Gas Limited Tax Variance Deferral Account to expand its applicability to record the impact of any tax rate changes for both the legacy Enbridge Gas Distribution and Union Gas Limited areas (i.e. to all of Enbridge Gas Inc.).

Simple interest is to be calculated on the opening monthly balance of this account using the Board-approved EB-2006-0117 interest rate methodology. The balance of this account, together with carrying charges, will be disposed of in a manner designated by the Board in a future rate hearing.

Account numbers are from the Uniform System of Accounts for Gas Utilities, Class A prescribed under the Ontario Energy Board Act.

Debit	-	Account No. 179-XXX Tax Variance Deferral Account
Credit	-	Account No. 300 Operating Revenues

To record as a debit (credit) in Deferral Account No. 179-XXX 50% of the variance in costs resulting from the difference between the actual tax rates and the approved tax rates included in rates as approved by the Board.

Debit	-	Account No. 179-XXX Tax Variance Deferral Account
Credit	-	Account No. 323 Other Interest Expense

To record, as a debit (credit) in Deferral Account No. 179-XXX, interest on the balance in Deferral Account No. 179-XXX. Simple interest will be computed monthly on the opening balance in the said account in accordance with the methodology approved by the Board in EB-2006-0117.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Board Staff (STAFF)

Reference: Exhibit B1/Tab 1/Schedule 1/Appendix A/pg. 33 and Appendix B/pg.34

Question:

For the ICM Deferral Account, the main journal entry is to record the difference between the actual revenue requirement for approved ICM projects and the actual revenues collected through ICM rates approved by the OEB. The OEB has developed accounting guidance for ICM/ACMs for electricity distributors in the Accounting Procedures Handbook Guidance, March 2015, topic #13 and 14.

a) Please discuss the applicability of the accounting entries to Enbridge Gas Distribution and Union Gas rate zones and revise the accounting orders as needed.
b) Please indicate how Enbridge Gas plans to track ICM related capital assets and depreciation.

Response

a) Enbridge Gas has reviewed the Board's guidance for the Advanced Capital Module/Incremental Capital Module in both the Report of the Board: *New Policy Options for the Funding of Capital Investments: The Advanced Capital Module*[1] *("Report of the Board")*, and the Ontario Energy Board Accounting Procedures Handbook Guidelines, dated March 2015 ("APH Guidelines"). Within the Report of the Board, Enbridge Gas perceives there to be a disconnect between Section 7.4, Reporting Requirements, and Section 7.5 Accounting Treatment (which is consistent with the accounting treatment identified in topics #13 and #14 of the APH Guidelines). In order to address the disconnect, Enbridge Gas has proposed the accounting orders as filed.

   Section 7.4, Reporting Requirements, of the Report of the Board states:

[1] EB-2014-0219, Report of the Board, *New Policy Options for the Funding of Capital Investments: The Advanced Capital Module,* dated September 18, 2014.

> At the time of the next cost of service or Custom IR application, a distributor will need to file calculations showing the actual ACM/ICM amounts to be incorporated into the test year rate base. <u>At that time, the Board will make a determination on the treatment of any difference between forecasted and actual capital spending under the ACM/ICM, if applicable, and the amounts recovered through ACM/ICM rate riders and what should have been recovered in the historical period during the preceding Price Cap IR plan term. Where there is a material difference between what was collected based on the approved ACM/ICM rate riders and what should have been recovered as the revenue requirement for the approved ACM/ICM project(s), based on actual amounts</u>, the Board may direct that over- or under-collection be refunded or recovered from the distributor's ratepayers"(emphasis added).[2]

Enbridge Gas's understanding of the above reporting requirements is that it will need to report on the variance between the actual ICM revenues collected in rates and the actual revenue requirement of the approved ICM projects, namely the revenue sufficiency or deficiency. Based on that understanding, Enbridge Gas does not believe the Board's Section 7.5 Accounting Treatment meets that requirement. The Board's accounting treatment only calls for certain revenue requirement / revenue sufficiency (deficiency) elements to be tracked in the deferral account, including capital spend placed in service (an input into a revenue requirement calculation, but not a revenue requirement component itself), depreciation, accumulated depreciation (again an input into a revenue requirement calculation, but not a revenue requirement component itself), and rate rider revenues, while other revenue requirement / revenue sufficiency or deficiency elements, such as taxes and cost of capital (which were considered in the determination of the revenue requirement to be recovered through the ICM rate riders), will continue to flow through the income statement, and therefore not be properly matched against revenues. In addition to this, Enbridge Gas also observes the following:

- Under the Board's accounting treatment, carrying charges are to be calculated on the incremental capital expenditure (capital spend placed into service), as well as, on the rate rider revenue amounts recorded in the deferral account. As a result, even if the amounts collected through rate

[2] EB-2014-0219, Report of the Board, *New Policy Options for the Funding of Capital Investments: The Advanced Capital Module,* dated September 18, 2014, Section 7.4 Reporting Requirements, Page 26.

riders exactly match the actual revenue requirement, an outstanding carrying charge would be calculated.[3]

- Under the Board's accounting treatment, when the deferral account is cleared, or amounts are reclassified out of the account at the next cost of service or Custom IR proceeding, the Company's income statement would be charged with cumulative amounts that relate to prior periods (i.e. out of period amounts that accumulated over the deferred rebasing / incentive regulation term)[4]

In order to address this Enbridge Gas has proposed to record the annual ICM revenue sufficiency/deficiency (for each of the EGD and Union rate zones) in its proposed ICM deferral accounts. Each year, the actual ICM revenues will be compared to the calculated ICM revenue requirement for approved ICM projects (for each of the EGD and Union rate zones), and any variance will be reflected as an adjustment to revenues, with an offsetting entry to the ICM deferral account. As a result of this proposal, each year the Enbridge Gas's financial statements will include all actual costs related to ICM projects, and a matched revenue stream, with any revenue sufficiency or deficiency recorded in the deferral account, which will appropriately attract carrying charges until the time of disposition.

b) Enbridge Gas will track ICM capital projects/assets by assigning distinct project numbers to each approved ICM project within its capital accounting systems. These distinct project numbers will be utilized to capture the capital costs associated with each approved ICM project.

[3] Ontario Energy Board Accounting Procedures Handbook Guidelines, dated March 2015, Section A.13, Pages 15-16.
[4] Ontario Energy Board Accounting Procedures Handbook Guidelines, dated March 2015, Section A.14, Pages 16-18.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Board Staff (STAFF)

Reference: Exhibit B1/ Tab 1/ Sch. 1/ Appendix H/pgs. 6-7, Enbridge Gas Distribution Inc., Fenelon Falls, Decision and Order EB-2017-0147, pgs. 10-16 and Union Gas Limited, 2019 Community Expansion Application EB-2018-0142, Exhibit A/ Tab 1/ pg. 3

Question:

The current application appears to reflect the System Expansion Surcharge (SES) framework approved by the OEB in Enbridge Gas Distribution's Fenelon Falls application. The current application does not address a Temporary Connection Surcharge (TCS) proposed by Union Gas in its 2019 Community Expansion application (which application is now in abeyance).

a) Has Enbridge Gas adopted verbatim the SES framework approved by the OEB in the Fenelon Falls proceeding? If not, please identify and explain any differences.
b) Does Enbridge Gas believe that the SES framework approved by the OEB in the Fenelon Falls proceeding is applicable to the former Union Gas rate zones? Please explain.
c) Does Enbridge Gas intended to seek approval of a TCS? Please provide a detailed response..

Response

When reviewing the evidence the Company discovered that the definition of a community expansion project set out at Exhibit B, Tab 1, Schedule 1, Appendix H, page 6 is not complete. Section 25 of Appendix H has been updated and is filed along with the interrogatory response.

a- c) Enbridge Gas has adopted the SES framework approved by the OEB in the Fenelon Falls proceeding for the EGD rate zone. Enbridge Gas intends to file updated community expansion applications with the Board later this year which will consider and address the adoption of the Fenelon Falls SES framework for the Union rate zones.

b) Enbridge Gas believes that the Fenelon Falls SES framework could be applicable to the Union rate zones. Enbridge Gas believes that a Board decision and order would be required to apply the Fenelon Falls SES framework to the Union rate zones.

22. The Capital Project Feasibility ("CAPF") program calculates customer revenue based on consumption levels input by the Customer Connections Representative ("CCR").

23. A load sheet is used to estimate consumption of commercial and industrial connections. The load sheet information is provided by the customer and contains consumption of various appliances installed at the premises.

24. For large volume connections, consumption information should include monthly volumes and the customer's contract daily demand.

25. The Investment Review group calculates revenue, based on the input consumption profiles and the most recent Board Approved revenue rates.

26. In its Community Expansion framework, the Board accepted the following new definitions which would enable projects to qualify for additional distribution revenue:
    - Community Expansion Project: A natural gas system expansion project which will provide first time natural gas system access where a minimum of 50 potential customers already exist, for which economic feasibility guidelines derive a Profitability Index ("PI") of less than 1.0
    - Short Main Extension Projects: All other forms of distribution system expansion which provide first time natural gas system access to customers where fewer than 50 potential customers in homes and business already exist and where the PI for the project is less than 1.0.
    - A natural gas system expansion project meeting either of the two definitions above that /u
      requires the SES and potentially other financing mechanisms in order for project economics to attain a PI of 1.0.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Board Staff (STAFF)

Reference: Exhibit B1/Tab 1/Schedule 1/Appendix F/Pg.31

Question:

In Article II (Gas Quality) of Union Gas' Rate M13 General Terms and Conditions, Enbridge Gas has proposed to replace the term "molar percent" with "mole percent" in several places.

a) Why has this change been proposed?
b) Why is the same change not proposed for the General Terms and Conditions applicable to other rate classes (such as on pages 42, 51 and 65)?

Response

a) "Mole percent" is the term used by the industry therefore going forward we will use this term instead of "molar percent", the term historically used by legacy Union.

b) Over time this change will be incorporated into other applicable General Terms and Conditions.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Board Staff (STAFF)

Reference: Exhibit B1/Tab 1/Schedule 1/Appendix I

Question:

The table in Appendix I shows the capacity available for PDO, remaining PDO and annual PDO shift for the period 2016 to 2020.

The remaining PDO (row 18) shows 26 TJ per day for 2017 and 2018 as filed in EB-2016-0245 and 31 TJ per day for the same period in EB-2017-0087. Please explain the reason for the change in the remaining PDO capacity.

Response

The table in Appendix I outlines the schedules that have been filed related to PDO in past proceedings. In proceeding EB-2016-0245 the amounts shown in 2017 and 2018 were a projection of expected activity. The assumption used in that proceeding was that all customers would elect to take PDO relief if provided to them, which resulted in the amount on row 18 being reduced from 31 TJ per day to 26 TJ per day. In proceeding EB-2017-0087 the amounts shown in 2017 reflect actual activity. When PDO relief was offered to customers with M12 service it was declined, resulting in the 31 TJ per day remaining as their Parkway Delivery Obligation.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Board Staff (STAFF)

Reference: Exhibit B1/Tab 2/Schedule 1/pgs.18-19

Question:

Enbridge Gas has requested incremental capital funding during the current deferred rebasing period for the Sudbury Replacement project as part of this proceeding. Due to the October 2018 in-service date, the project falls between qualifying for incremental rate treatment under Union Gas' 2014-2018 capital pass-through mechanism and qualifying for incremental rate treatment under the ICM. Given the magnitude of the $95.3 million investment in the Sudbury Replacement project, Enbridge Gas has indicated that incremental funding of the project is required. Union Gas was not able to reprioritize 2018 capital investment in order to fund this investment through existing rates.

a) Does the Sudbury Replacement project qualify for ICM funding under the OEB's ICM/ACM capital funding policy? If yes, please explain.
b) What was the total capital investment of Union Gas in 2018 excluding the Sudbury Replacement project?
c) If the OEB finds that the Sudbury Replacement project does not qualify for ICM funding, how would the decision impact the future capital investment plans of Enbridge Gas?
d) In Exhibit B1/Tab 2/Schedule 1/Pg. 25, Enbridge Gas has indicated that the budget has been updated from the approved filing budget of $74.1 million in EB-2017-0180. Please explain the reasons for the increase in the actual spend and outline the steps that Union Gas undertook to reduce the spending.
e) Please provide the cost components of the Sudbury project that exceeded the initial estimates and corresponding notes explaining the variance.

Response

a) Yes, it is Enbridge Gas's position that the Sudbury Replacement project qualifies for ICM funding under the OEB's ICM/ACM capital funding policy. Enbridge believes the intention of the OEB's policy is to ensure regulated entities make prudent capital decisions while under a Price Cap incentive rate-setting mechanism.

The Sudbury Replacement Project was required to ensure safe and reliable service to customers in the Union North rate zone. As per the Board's Decision and Order in the Sudbury Replacement Project proceeding:

> *The OEB finds that the necessity for an expedited completion of the Sudbury Replacement Project to address the safety and reliability risks identified by Union is a "special circumstance" that justifies granting the requested exemption.*[1]

Please refer to Exhibit B1, Tab 2, Schedule 1, pages 18 to 20 for further background on the ICM funding request for the Sudbury Replacement Project.

b) Total capital spend for legacy Union in 2018 was $519.2 million. Excluding capital pass-through of $80 million and Sudbury spend of $86.3 million, the remaining spend is $352.9 million.

c) Enbridge Gas does not select projects based on their funding mechanisms. Projects are evaluated and prioritized using a methodology designed to ensure maintenance capital resources are employed to address the highest priority items across all asset categories.

d) Please see Exhibit I.EP.16.

e) Please see Exhibit I.EP.16.

[1] EB-2015-0042 Decision and Order, April 23, 2015, page 2.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Board Staff (STAFF)

Reference: Exhibit B1/Tab 2/Schedule 1/pgs. 22-24

Question:

Enbridge Gas is seeking recovery under ICM for the NPS 30 Don River Replacement Project. The project involves replacement of approximately 0.25 km of NPS 30 XHP on the Don River Bridge crossing with a new NPS 30 XHP under the Don River through the use of trenchless technology. In the EB-2018-0108 leave to construct application the budget for the project was estimated to be $25.6 million. The updated budget is $35.4 million.

a) Please explain the reasons for the increase in the budget. Please provide the cost components of the project that exceeded the initial estimates and corresponding notes explaining the variance.
b) Has Enbridge Gas considered other construction methods or technology that could bring the spending in line with the original forecast?

Response

a) The increase in the Don River Replacement Project budget is due to indirect overhead costs that were not included in the EB-2018-0108 filing. Please see the response to Energy Probe Interrogatory #16(a) found at Exhibit I.EP.16.

b) Please refer to response a) above for explanation on variance to the original forecast.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Board Staff (STAFF)

Reference: Exhibit B1/Tab 2/Schedule 1/pgs.25-27

Question:

The budget for the Kingsville Reinforcement Project has been updated from the EB-2018-0013 filing budget of $105.7 million to $121.4 million.

a) Please explain the reasons for the increase in the budget. Please provide the cost components of the project that exceeded the initial estimates and corresponding notes explaining the variance.

Response

Please see Exhibit I.EP.16, part a).

ENBRIDGE GAS INC.
Answer to Interrogatory from
Board Staff (STAFF)

Reference: USP - Exhibit C1/Tab 1/ Schedule 1/ pg. 6

Question:

In its application, Enbridge Gas has indicated that, “the integration of Enbridge Gas will drive efficiencies and synergies, create new opportunities for growth, and form a stronger platform to deliver superior value and service to customers. Over time the AMP process will integrate the Enbridge Gas Distribution and Union Gas plans into one”.

a) Will Enbridge Gas submit an integrated USP and AMP, covering Enbridge Gas Distribution and Union Gas in one document, by the 2021 filing?
b) Will the integrated document be organized to comply with the RRF Chapter 5 filing requirements defined in Exhibit C1, p. 46, Table 5, col 1?

Response

a) Yes.

b) Please see Exhibit I.STAFF.34.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Board Staff (STAFF)

Reference: USP - Exhibit C1/Tab 1/ Schedule 1/ pgs. 7-8

Question:

Enbridge Gas Distribution owns and operates 37,600 km of pipelines for the transportation and distribution of gas. It is also owns 91 billion cubic feet (bcf) of regulated storage and operates a total of 134 bcf of storage. Union Gas' natural gas assets include 70,000 km. of distribution, storage and transmission pipelines, 188.1 PJ of natural gas storage capacity and 760,000 horsepower of compression.

a) What overall integrated optimization efficiencies does Enbridge Gas project through optimization of storage and transmission for its in-franchise customers as a result of integration of Union Gas and Enbridge Gas Distribution supply, storage and transportation contracts and storage and transmission assets? Please provide a breakdown by each category including compressor fuel savings.
b) When does Enbridge Gas expect to operate the Enbridge Gas Distribution and Union Gas storage and transmission assets, and supply and transmission contracts on a fully integrated basis?
c) What transmission and storage efficiencies does Enbridge Gas expect to achieve by shifting Enbridge Gas Distribution from a contract customer of Union Gas to an in-franchise integrated operation under Enbridge Gas?

Response

a-b) Enbridge Gas has been operating as an amalgamated entity for only four months and is not in a position to provide any estimates of optimization or integration savings.

c) Enbridge Gas does not expect to achieve efficiencies by shifting legacy EGD from a contract customer of legacy Union to in-franchise. As outlined in the MAADs proceeding, although the transportation and storage contracts ceased to exist at January 1, 2019 they have been replaced with term sheets which contain the same terms (i.e. space, deliverability, ratchets, etc.) as the previous contracts.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Board Staff (STAFF)

Reference: USP - Exhibit C1/Tab 1/ Schedule 1/ pgs. 10-11

Question:

Enbridge Gas has indicated that the major contributing factor to Union Gas' recent infrastructure expansion relates to the growth in natural gas production from the Marcellus and Utica shale basins which are within 300 km of Ontario and shippers that are accessing the Dawn Hub. As a result, the flow of natural gas on the Canadian and U.S. pipeline grid is changing and continuing to evolve. Although difficult to forecast, going forward Enbridge Gas expects further growth along the Dawn Parkway System driven by further demand growth in the U.S. Northeast and Ontario Local Distribution Companies, as well as natural gas fired generation due to Ontario's nuclear refurbishment plan, when executed.

a) How integral will this source of supply be in satisfying Enbridge Gas' in-franchise customer needs in the future?
b) Is the decision to incorporate increasing amounts of Marcellus and Utica supply volumes exclusively driven by the need to acquire the lowest cost gas?
c) Are other factors considered such as the environmental effects of developing these sources of supply?

Response

a) Production in the Marcellus and Utica shale basins is expected to grow over the next 10 years and supply from these basins is an integral part of Enbridge Gas's balanced gas supply portfolio. Enbridge Gas sources supply directly from the Marcellus and Utica utilizing the combined 260,000 Dth/d long-term NEXUS contracts to deliver supply to Dawn. In addition, Enbridge Gas's gas supply plan is expected to continue to include commodity purchases from various supply points that are connected to the Marcellus and Utica basins including Dawn, Niagara, Chippawa, Michigan and Chicago.

b) Future gas supply and transportation procurement decisions will be made by balancing Enbridge Gas's gas supply planning principles. The guiding principles for the assessment of the gas supply plans include: Cost-effectiveness, Reliability and Security of Supply and Public Policy. Cost is a consideration; however, "the need to acquire the lowest cost gas" is not the driver. The gas supply plan is developed to be cost-effective. Cost-effectiveness is achieved by appropriately balancing gas supply planning principles and executing the supply plan in an economically efficient manner.

c) The gas supply plan will be developed by appropriately balancing gas supply planning principles. Its development will consider alignment with public policy which is one of the principles.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Board Staff (STAFF)

Reference: USP - Exhibit C1/Tab 1/ Schedule 1/ pgs. 12-14

Question:

Each year Enbridge Gas completes an annual budget and multi-year Long Range Planning (LRP) process. Prior to 2019, the process was completed separately for Enbridge Gas Distribution and Union Gas. Starting in 2019, the process will be completed for Enbridge Gas as a whole.
The demand forecast is the starting point for the budget and LRP process, and includes a detailed customer and volume forecast. The demand forecast provides inputs into the four main components of the company's financial budget and LRP process (1. Distribution Revenue, 2. Storage and Transportation Revenue, 3. Operating and Maintenance Costs, and 4. Capital Investment). Figure 2 on page 14 provides a process map for the budget and LRP process. The four major components of the process are well defined in the filing but the integration of those four components at the executive level drives the questions below.

a) Are Shared Services including Administrative and General expenses and other Non-commodity Carrying system expenses allocated to the four main budget components?
b) How are the various submissions prioritized at the Budget and LRP Consolidation step in the process? Is there a standardized numerical ranking that allows a direct comparison between each item of the four main budget components? If not, what process is used to approve or reject the various competing expenditures?

Response

a) Shared Services function expenses are budgeted as part of the overall O&M budget process. A portion of these expenses would be allocated to capital projects through the capitalized overhead process for both the EGD and Union rate zones.

b) There is no specific ranking of the four main components of the budget process, other than in the area of Capital Investment which is prioritized/optimized based on the Asset Management planning process in place for both the EGD and Union rate zones. Please see Exhibit I.BOMA.22 for the prioritization/optimization process.

The consolidated budget is reviewed by the Company’s Senior Executive Team and adjustments are made to meet overall company objectives.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Board Staff (STAFF)

Reference: Exhibit C1/ Tab 1/ Schedule 1/ Section 4.2/ pg. 35 and Exhibit C1/ Tab 2/ Schedule 1/ pg. 66

Question:

Enbridge Gas notes that Enbridge Gas Distribution and Union Gas have unique investment categories. These categories have been mapped in Table 2 to the four general investment categories outlined in Chapter 5 of the Filing Requirements for Electricity Applications. In the Enbridge Gas Distribution AMP, nine asset classes (**Figure 4.1-2**) are used to categorize and manage investment decisions. Each asset class has its own asset class manager and asset class director. Both roles are responsible for understanding the operational risks and opportunities associated with their respective asset class and managing the portfolio of work to ensure risk is managed to the lowest practicable level and optimum value is realized.

a) In order to clarify cost significance of each asset class, please provide a table in which the overall Enbridge Gas Distribution expenditures (Capital and O&M) for each asset class are shown?
b) Please also indicate in the table the predominant Chapter 5 investment category for each asset class (System Access, or System Renewal, or System Service, or General Plant)?

Response

a) & b) Please refer to Exhibit I.BOMA.22 for capital expenditures. O&M expenditures are not summarized in the Asset Management Plan.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Board Staff (STAFF)

Reference: USP - Exhibit C1/Tab 1/ Schedule 1/ pgs. 37-41

Question:

Enbridge Gas' total historical and overall forecasted 10-year spend profile by investment category is provided in Figure 6 of the USP. Similarly, the 10-year spend profile of Enbridge Gas Distribution and Union Gas is provided in figures 7 and 8 respectively. The spending profile of Enbridge Gas Distribution and Union Gas is developed using the current AMP methodologies of the respective companies.

a) How will Enbridge Gas and its customers benefit in terms of costs and rates as a result of the integration of the two AMP methodologies?
b) Would it be reasonable to limit the major capital expenditures for Enbridge Gas Distribution and Union Gas to all but the essential expenditures until the fully integrated USP and AMP programs are filed in 2021?
c) In each of Figures 6, 7 and 8, the Overhead line item comprises nominally 20% of each year's expenditures. Please provide the major cost components of this line item.
d) Please confirm if the Overhead line item includes any OM&A costs. If not, please provide a reference where the associated OM&A costs can be found.

Response

a) Enbridge Gas customers will benefit as a combined asset management process and asset management plan will describe:

- Policy and strategies for achieving effective asset management for all assets within Enbridge Gas's regulated operations;
- Process and governance for asset management;
- Asset class objectives and life cycle management policies;
- Asset inventory, condition methodology, condition findings, risks, opportunities, and strategies; and,
- Optimized 10-year capital expenditures required to manage assets from 2019-2028.

This is a ratepayer benefit as it provides transparency into how and why costs will be incurred. It demonstrates Enbridge Gas's commitment to safety and reliability while managing costs effectively and provides a long-term view and rationale for expenditures.

b) No, both legacy Asset Management System of Union Gas and Enbridge Gas Distribution are founded on asset management principles of ISO 5500x. Enbridge Gas has identified projects to address asset condition and risk mitigation based on the respective asset management frameworks to date. In cases where the integrated assets may impact the solution identified, projects are planned in the future to allow the integration work to further inform the solution. As a result, the major capital expenditures identified in the respective AMPs are considered to be essential expenditures.

c) Figure 6 for Enbridge Gas is the sum of the overheads presented in Figure 7 and Table 8 for EGD and Union respectively.

Figure 7 - 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

Table 8 – 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

d) The overhead categories of A&G, DLC and OH listed in part c) above are all allocations of OM&A costs that have direct causal linkage to support capital projects.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Board Staff (STAFF)

Reference: Exhibit C1/Tab 1/Schedule 1/pgs.39-40

Question:

Enbridge Gas Distribution's projected spend totals $2.57 billion and $5.17 billion over the five (to 2023) and ten year period (to 2028) respectively. Union Gas' projected spend totals $2.61 billion and $4.93 billion over the five and ten years respectively.

Did the projected spend change as a result of the feedback from the customer engagement process? If no, please provide reasons. If yes, please provide details of the changes and the impact on the specific investment category.

Response

In the development of Enbridge Gas's business planning, customer views were taken into consideration when designing the AMPs in terms of balancing the pace of capital spend while maintaining safety and reliability levels.

As referenced in Exhibit C1, Tab 3, Schedule 1, page 21 and Exhibit C1, Tab 2, Schedule 1, page 54, from the Customer Engagement consultation conducted by both Ipsos and Innovation Research Group, for legacy EGD and legacy Union respectively, customers identified that the most important outcomes are price, safety and reliability. In general, customers are satisfied with the reliability and the safe delivery of natural gas, and they feel that the utility should invest in maintaining the current levels of reliability. Customers are satisfied with the value they receive for the money they pay for their service and the majority found it acceptable to pay more on their bills to cover the cost associated with aging infrastructure to maintain the current level of reliability and safety.

All capital requirements support the maintenance of existing assets based on the conditions and strategies outlined in the respective asset management plans. Timing is based on risk, asset life cycle strategies, with consideration to ratepayer impact.[1]

[1] Exhibit C1, Tab 2, Schedule 1, page 382.

Portfolios for Enbridge Gas such as Fleet Purchases, TIS, CRES (REWS), Stations, Measurement (Customer Assets) have a relatively stable level of spend.

Specific to Union, in relation to spending on buildings, equipment and IT, Exhibit D1, Tab 2, Schedule 1, page 71 reveals that customers believe that Union should spend what is needed compared to simply making do with the building, equipment and IT it currently has.

There are cases in which customer feedback for ensuring the long-term health of the system have supported increased spending. An example of this would be the steel mains replacement program for EGD and other specific project examples such as Union's Windsor Line and London Line replacement projects as well as EGD's NPS 30 Don River replacement project.

Although customer knowledge varies on GHG reduction initiatives and on renewable natural gas, there is alignment with customers on the preference to invest in renewable energy sources to reduce the overall network consumption and in conservation programs.[2] In Union's customer engagement in particular, results from businesses indicate a preference to not go beyond minimum requirements, and residential seem to support an increase in rates to proactively seek opportunities.

Enbridge Gas is committed to providing consumers access to safe, reliable and affordable natural gas services. Enbridge Gas is also committed to its role in offering balanced solutions that support emission reduction targets, including: (i) energy savings information that enables consumers to optimize their energy consumption; (ii) a portfolio of Board-approved energy conservation programs to facilitate transparent and measurable conservation; and, (iii) development and testing of low-carbon technology solutions. See Enbridge Gas' USP for more details.[3]

The upgrade and obsolescence programs within the measurement portfolio have more flexibility than the Meter Exchange Program and were adjusted to balance the overall portfolio spend for 10 years to a steady pace while satisfying the risk mitigation required for each program.[4]

On the specific topic of automated meter reading in Union's customer engagement survey, the customer feedback indicates a preference to install these meters over time in order to minimize costs. Legacy Union has decided to replace meters with automated meters over time in alignment with customer preferences.

[2] Exhibit C1, Tab 2, Schedule 1, page 54.
[3] Exhibit C1, Tab 1, Schedule 1, pages 30 to 32.
[4] Exhibit C1, Tab 3, Schedule 1, Table 5.4.3.6.1 page 95.

In addition, EGD has a Customer Experience Transformation project, consisting of initiatives that span multiple asset subclasses within the TIS asset class. This two year project proactively transforms the way we do business with our customers and to improve customer interactions.[5] More information on Customer Experience can be found at Exhibit C1, Tab 2, Schedule 1, page 354.

For bare and unprotected steel, "Union's 2017 customer engagement survey found that 50 per cent of those surveyed recommend prioritized replacements" supporting the strategy to replace over the next six years.[6]

"MOP verification was also included in the 2017 customer engagement survey: 40 per cent recommend proactively implementing industry standard. Spreading the verifications over several years will keep costs down and proactively implement an industry standard, which provides additional support for this program. Starting this program as forecast will mitigate the need for higher expenditures in a shorter time frame to meet these expected future mandated requirements."[7]

Within the Distribution Growth portfolio the customer feedback for a desired steady pace of spend is managed in planning the Distribution and Station Reinforcement projects to a combined annual spend that is consistent over the 10 year forecast.[8]

[5] Exhibit C1, Tab 2, Schedule 1, page 348.
[6] Exhibit C1, Tab 3, Schedule 1 page 83.
[7] Exhibit C1, Tab 3, Schedule 1 page 85.
[8] Exhibit C1, Tab 3, Schedule 1, Table 5.2.1.1, page 71.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Board Staff (STAFF)

Reference: USP - Exhibit C1/Tab 1/ Schedule 1/ pgs. 46-47

Question:

Enbridge Gas has indicated that the AMPs were built using guidance from the OEB's filing requirements for natural gas distributors. Further guidance was obtained through the more detailed Chapter 5 of the filing requirements for electric distributors. Table 5 provides the alignment of sections that comprise each of Enbridge Gas Distribution's and Union Gas' AMPs to the Chapter 5 requirements.

Going forward, does Enbridge Gas plan to align Section 5.0 of overall USP to be the same format and content as outlined in Chapter 5 of the filing requirements. In particular to comply with Section 5.3 "Asset Management Process", specifically sub-sections 5.3.1, 5.3.2, 5.3.3 and 5.3.4?

Response

Enbridge Gas is still assessing its future asset management process and will create an asset management plan with industry best practice and OEB filing requirements in mind. Any future asset plan will be compliant with the intent of the "Chapter 5 Consolidated Distribution System Plan" document.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Board Staff (STAFF)

Reference: USP - Exhibit C1/Tab 1/ Schedule 1/ pg. 53

Question:

Another way Enbridge Gas Distribution and Union Gas have historically sought to continually improve is through industry engagement. Key subject matter experts involved in the design and operations of assets are engaged in industry related code committees and industry best practices to better understand compliance requirements, to support the improvement of codes and standards that drive operational safety, and to learn and share best practices from industry peers. Examples include active membership of subcommittees for the Canadian Standards Association – Oil and Gas Pipeline Systems, Canadian Gas Association and American Gas Association surveys and workshops and participation in AGA peer reviews.

Please provide specific examples of improvements in Enbridge Gas' asset management planning and practices that have occurred as a result of benchmarking against the best practices in the industry? Where possible, please provide specific examples.

Response

Exhibit C1, Tab 2, Schedule 1 pages 55-57, section 3.1 of the EGD rate zone's AMP addresses asset management improvements and section 3.4 discusses the approach taken to assess asset management planning and practices through an independent review.

Similarly for the Union rate zones' AMP, Exhibit C1, Tab 3, Schedule 1, pages 32 to 33 outlines the approach to review asset management practices and continual improvement.

Participation of the CGA committees for Integrity Management and Asset Management have helped shape Enbridge Gas's programs and approach to risk management. Further, involvement with the CSA Technical Sub-committees helps Enbridge Gas: 1) influence and gain insight on issues that impact the safety and reliability of assets, 2) define metrics to measure performance, and 3) structure the programs and type of tools used to complete integrity assessments.

As part of the amalgamation of Union Gas and Enbridge Gas Distribution, the quality management resources have been combined into one group within Enbridge Gas. The goal of combining quality management resources is to ensure an integrated approach to risk management, identifying and auditing key safety processes and field procedures.

Through chairing and participating in the committee for development of the CSA Z260 – Pipeline Safety Metrics, Enbridge Gas is concurrently developing an internal standard to align with the CSA Z260 Transmission standard and developing proposed draft metrics for CSA Z260 Distribution for the purpose of gaining insight and trends that can be shared as comments and lessons learned to other industry participants.

Setting of the compressor metrics is done in consideration with AGA Compressor metrics. Monitoring these metrics has led to further investigation of a poor hot weather start performance at Dawn Plant J. The resolution recommendation, involving the original equipment manufacturer, has led to a proposal to increase the horsepower of the starter motor in the future.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Board Staff (STAFF)

Reference: AMP - Exhibit C1/Tab 2/ Schedule 1/ pg.19

Question:

The AMP states that the Asset Management Program considers all OEB-regulated assets, which have been grouped into nine classes: *Pipe, Stations, Storage, Customer Assets, Fleet & Equipment, Technology & Information Services (TIS), Real Estate & Workplace Services (REWS), Customer Growth*, and *Business Development.* Investment decisions are categorized and managed on an asset class basis, where each asset class has a unique set of objectives and life cycle management policies that guide decision-making. With an understanding of the asset inventory and the evaluation of condition and risk, resultant strategies are outlined.

From the statements in this Section (i.e. 1.6 "Asset Classes") it is not clear whether the implementation of the asset management process is consistent across the EGD asset classes (i.e. prioritization of assets among the assets classes which would be selected for monitoring as part of the asset management process may not have common basis to allow comparison).

a) Please explain or point to a section in this document which explains the sources used to establish these EGD Asset Classes
b) Customer Growth and Business Development are referred to as assets. Please explain how these are considered to be assets?
c) What are the common basis on which the prioritization of investments across assets classes is achieved (e.g. system/equipment health indexing, common asset registry information, end of life criteria etc.)?

Response

a) EGD Asset Classes were defined based on categorization of EGD's regulated assets, the organizational structure managing these assets and ISO 5500x. Additional consideration was given to the grouping of like assets that performed a specific function, had similarities in operation and/or life cycle strategy and, in some cases, were aligned by organizational function Evidence references to where this is discussed in the EGD AMP are located is Section 4.[1]

b) Customer Growth and Business Development are Asset Classes; their respective assets and lifecycle policies are described in Sections 5.1 and 5.9 of the AMP.[2]

The Customer Growth Asset Class represents a significant annual spend to the organization and bridges multiple asset classes. The organization made the decision that Customer Growth would be best managed as its own Asset Class. Once the assets are in service the management of the asset falls within the respective asset class such as Stations, Pipe, and Customer Asset Classes.

In the case of the Business Development Asset Class, there is a relatively small asset inventory and the decision was made to align this asset class with the organizational structure that manages the assets.

c) Investments are optimized based on the Asset Management Principles outlined in Section 4.1.3.4 Optimize Portfolio Based on Asset Management Principles (p. 71-4). Please refer to the Asset Management Core Process steps Risk Management (Section 4.2.1 p. 79), Solution Planning (Section 4.2.2 p. 83) and Portfolio Optimization (Section 4.2.3 p. 84).

[1] Exhibit C1, Tab 2, Schedule 1, page 62.
[2] Exhibit C1, Tab 2, Schedule 1, page 95; and page 361.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Board Staff (STAFF)

Reference: Exhibit C1/ Tab 2/ Schedule 1/ Section 1.8 – Condition and Strategy Overview, pgs. 20-41

Question:

Enbridge Gas Distribution presents series of asset class tables starting on page 20 through to page 41. The heading on the majority tables is "ASSET SUBCLASS AVG. AGE (YR)/CONDITION RISK / OPPORTUNITY MAINTENANCE STRATEGY REPLACEMENT / RENEWAL STRATEGY"

a) Please present the capital values for each of the assets in these tables?
b) Typical End-Of-Life (EOL) criteria would address function/purpose, economy of continued operation, safety, reliability/ risk, and design/ obsolescence). Has Enbridge Gas defined such EOL criteria? If so, does it apply them in determining asset replacement rates? If yes, please explain how this has been done?
c) Corporate values do not appear to be consistently reflected in description of RISK/OPPORTUNITY column. Examples are to be seen on page 20 for "Integrity Mains" and for Distribution Steel Mains. There is no explicit mention of injury/Loss of Life under the Risks/ opportunity. In general, expenditures to prevent injury/loss of life would be expected to receive the highest weighting, with proportionally less financial weighting to reducing other risks such as "relighting customer gas appliances". Would it be possible to show the linkage from Risk/opportunity to the financial weighting applied to risks in order to determine the appropriateness of the balance struck and where proportionate savings have been allocated for lower impact risks? If yes, please present or highlight this?
d) Discussion of risk of injury/loss of life is generally associated with the three risks listed: Safety, Financial and Customer satisfaction. Does the Enbridge Gas asset management policy and strategy fully reflect these risks? If so, please substantiate the linkages.

RISK / OPPORTUNITY

Risks identified for integrity mains:

Safety Risk: Gas leaks and migration through underground infrastructure into buildings can result in gas accumulation and explosions.

Financial Risk: Total repair costs, commodity loss, relighting customer gas appliances, regulatory penalties, and any property damages caused by a gas leak.

Customer Satisfaction (CSAT) Risk: Greenhouse Gas (GHG) emissions, environmental impact, extensive customer outage, and reputational damages.

Emergency Replacement Program: Main repairs or reactive replacements to address leaks and condition issues as identified. The approach depends on the extent of the main's poor condition. Localized poor condition is managed through pipeline repairs. Broader condition issues are managed through more extensive replacement.

e) Failure curve predictions for pre-1985 plastic mains vs/risk/opportunity (pdf p83)

Pre-1985 plastic mains are found to be in good condition; however, the failure curve predicts a rapid degradation over a very short period of time.

"The maintenance strategy for distribution plastic mains requires a leak survey to be conducted every five years"

Please explain or point to a section in this document which explains:

I. How is the shape of the failure curve referred to above derived and verified?
II. Is the failure curve referred to above qualified through laboratory examination of Enbridge Gas Distribution field samples sufficient to reliably predict rate of progression and ultimate failure? If so, please provide an example of how it is used in the analysis to narrow the uncertainty in the risk?

Response

a) By “capital values” Enbridge Gas believes the question is referring to the capital investment associated with each asset sub-class or category of spend. The summary tables at the end of each asset class section in Section 5 of the EGD rate zone’s AMP provide this information, and are reproduced in Attachment 1 with a column added (first column) to better align with the summary tables at Exhibit C1, Tab 2, Schedule 1, pages 20 and 41.

b) No. The term “End-of-Life” used is a generic term used to imply an asset’s end state. The renewal/maintenance strategy takes into consideration each asset class, and their unique objectives and life-cycle management policies. As shown in Figure 4.1-6, several inputs are used to inform decision-making during an asset’s life.[1]

Consistent criteria were used for each asset section in the EGD rate zone’s AMP: “*Condition Methodology”, “Condition Findings*”, “*Risk and Opportunity*”, and “*Strategy*”. This was designed to clearly outline the methodology and subsequent conclusions that led to each renewal /maintenance strategy.

c) The series of tables starting on page 20 through to page 41 in the EGD rate zone AMP was intended to provide a high level summary by asset subclass category.
In its risk management framework, Enbridge Gas weighs safety risk higher than customer satisfaction and financial risk. This is presented in the EGD rate zone AMP strategy and planning section:

- Risk tolerances are defined for each risk dimension and *Figure 4.2-4: Safety Risk Matrix* on this page illustrates the lower tolerance for safety related risks compared to Financial (*Figure 4.2-5*) and Customer Satisfaction (*Figure 4.2-6*).[2]
- When calculating discounted lifetime risk reduction, “customer satisfaction and financial risk are discounted over the life of the asset, while safety risk is not, as it is of paramount importance.”[3]

d) Yes. As EGD’s asset management policy states in Section 4, under Strategy and Planning:

> Core asset management goals are employee and public safety, compliance, financial performance, operational reliability, environmental sustainability, and customer satisfaction.[4]

[1] Exhibit C1, Tab 2, Schedule 1, p. 70.
[2] Ibid., p.82.
[3] Ibid., p.89.

Risk assessments use the dimensions of Safety, Financial, and Customer Satisfaction (CSAT) to quantify risk. These are described in Table 4.1-2: EGD's Risk Dimensions and align to the Enterprise Strategic Priorities and the Asset Management Core Process.[5]

Figure 4.1-8 illustrates how EGD's Asset Management Policy, Strategies and Risk Dimensions align with the Company's Enterprise Strategic Priorities. This alignment is the core of EGD's Asset Management Strategic Framework.[6]

e)

I. The failure projection is created by applying statistical model on historical failure data from 2007-2017. The projection is being monitored and verified against actuals on an annual basis. Sections in the EGD rate zone AMP that explain this are provided below.

> a leak projection model created by applying a structured methodology to convert historical failure data into a statistical model that forecasts the probability of failure (PoF). The leak projections are refined with input obtained through direct assessment, internal and external industry studies, and SMA input.[7]
>
> EGD continually monitors the performance of these assets and refines its analytical models based on best available data. As the quality of models and data continue to improve through the Plan-Do-Check-Act methodology, EGD will be better able to predict asset condition and manage its long term replacement strategy accordingly.[8]

II. The EGD rate zone has collected gas pipe samples of pre-1977 plastic mains to send to the Gas Technology Institute ("GTI") for testing and analysis. The GTI was able to produce a Rate Pre-process Method model for the pre-1977 Aldyl A plastic mains, which was used to estimate time to first failure for this asset sub-class.

> In addition to statistical modeling, EGD has also concluded an extensive study on pre-1977 Aldyl A plastic pipe with GTI to develop data-driven predictions on the remaining useful life expectancy of the Aldyl A plastic pipe used in the EGD system.[9]

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[4] Ibid., p.64.
[5] Ibid., p.71.
[6] Ibid., p.76.
[7] Ibid., p.132.
[8] Ibid., p.138
[9] Ibid., p.132.

Table 1: Customer Growth Capital Summary ($ Thousands)

Asset Subclass	Sector	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	10-year Forecast
Various	**Commercial**	22,946	23,804	24,304	24,049	24,027	23,710	23,500	22,932	22,731	22,757	234,761
	Industrial	3,763	3,903	3,985	3,943	3,940	3,888	3,853	3,760	3,727	3,732	38,494
	Residential	72,126	74,823	76,393	75,593	75,524	74,528	73,866	72,083	71,451	71,532	737,919
	Total	**98,835**	**102,530**	**104,681**	**103,585**	**103,491**	**102,126**	**101,219**	**98,775**	**97,909**	**98,021**	**1,011,174**

Table 2: Pipe Capital Summary ($ Thousands)

Asset Subclass	Program/Project Name	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	10-year Forecast
Distribution Mains - Steel	**Steel Mains Replacement**	18,844	21,599	24,117	26,929	30,068	33,574	37,489	41,859	46,740	52,189	333,408
Distribution Mains - Steel & Integrity Mains	**Corrosion Prevention Program (Anode Replacement)**	1,211	1,229	1,247	1,265	1,284	1,303	1,323	1,342	1,362	1,383	12,949
Various	**Pipe Emergency Replacement**	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	20,000
Distribution Mains - Steel	**Major Pipelines**	25,401	2,600	9,240	40,642	2,650	10,750	600	-	-	-	91,882
Distribution Mains - Plastic	**Vintage Plastic Replacement**	1,889	2,276	2,746	3,319	4,018	4,870	5,910	7,178	8,726	10,615	51,546
Various	**Relocations**	16,017	27,006	10,550	9,700	9,700	9,700	9,700	9,700	9,700	9,700	121,473
Various	**Engineering Technology**	-	1,358	1,093	1,382	583	-	-	-	-	-	4,415
Integrity Mains	**Integrity Retrofits**	3,855	-	-	-	-	-	-	-	-	-	3,855
Distribution Services & Distribution Risers	**Service Relay Blanket**	17,723	20,296	21,195	22,175	23,183	24,261	25,233	26,223	27,236	28,252	235,777
Distribution Risers - Copper	**Copper Riser Replacement Program**	4,407	4,483	6,841	9,279	10,840	13,005	19,539	24,846	25,276	25,713	144,227
Various	**Reinforcements**	20,332	13,167	5,193	4,924	11,602	16,728	18,912	2,845	504	-	94,207
	Pipe Total	**111,678**	**96,013**	**84,222**	**121,615**	**95,928**	**116,190**	**120,705**	**115,993**	**121,543**	**129,852**	**1,113,739**

Table 3: Stations Capital Summary ($ Thousands)

Asset Subclass	Program/Project Name	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	10-Year Forecast
Gate & Feeder Stations	**Gate & Feeder Station Program**	7,504	12,987	7,741	11,469	8,652	13,051	7,240	6,848	3,612	3,484	82,586
District Stations	**District Stations Rebuild Program**	6,500	8,189	7,000	8,000	7,500	7,500	7,500	7,500	7,500	8,500	75,689
Header Stations	**Header Stations Rebuild Program**	924	924	924	924	924	924	924	924	924	924	9,240
Sales Stations	**Sales Stations Rebuild Program**	1,100	1,500	2,000	2,035	2,071	2,107	2,144	2,181	2,219	2,258	19,615
Sales Stations	**Inside Regulator Relocation and ERR Program**	500	500	500	500	500	500	500	-	-	-	3,500
Gate & Feeder Stations	**Integrity Retrofits**	2,573	1,850	1,197	1,500	1,400	450	-	-	-	-	8,971
Gate & Feeder Stations	**Telemetry Program**	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	14,000
Gate & Feeder Stations	**M&R Compliance**	200	200	200	200	200	200	200	200	200	200	2,000
Various	**Station Emergency Replacement**	200	200	200	200	200	200	200	200	200	-	1,800
	Stations Total	**20,901**	**27,750**	**21,163**	**26,228**	**22,846**	**26,332**	**20,108**	**19,253**	**16,055**	**16,766**	**217,401**

Table 4: Storage Capital Summary ($ Thousands)

Asset Subclass	Program/Project Name	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	10-Year Forecast
Gas Compressors	**Compressor Equipment**	24,066	27,870	27,589	10,513	10,999	5,953	4,934	3,299	2,489	2,660	120,370
Various	**Integrity Initiatives**	577	771	1,040	735	728	851	1,075	744	1,113	1,134	8,767
Various	**Field Lines**	2,079	1,343	498	1,006	1,496	930	398	3,509	1,225	225	12,709
Reservoirs	**Wells and Well Equipment**	7,246	3,976	3,298	2,143	1,167	3,749	1,927	11,098	739	1,403	36,746
Various	**Measurement and Regulating Equipment**	14	14	14	729	209	14	14	14	79	14	1,118
	Storage Total	**33,981**	**33,974**	**32,440**	**15,126**	**14,599**	**11,497**	**8,349**	**18,664**	**5,646**	**5,435**	**179,710**

Table 5: Customer Assets Capital Summary ($ Thousands)

Program/Project Name	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	10-Year Forecast
Measurement Systems	38,126	40,749	39,328	41,973	43,558	51,512	44,097	43,694	51,527	44,500	439,065
Regulation, Safety, and Piping	2,411	2,427	754	461	463	465	466	468	470	-	8,385
Below Ground and Internal Piping Systems	55	55	-	-	-	-	-	-	-	-	110
Customer Owned Systems	443	400	203	203	203	203	400	400	400	400	3,257
Customer Assets Total	41,036	43,631	40,285	42,637	44,224	52,180	44,964	44,562	52,398	44,900	450,816

Table 6: Real Estate & Workplace Services Capital Summary ($ Thousands)

Program/Project Name	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	10-Year Forecast
Arnprior	-	-	500	1,600	-	-	-	-	-	-	2,100
Barrie	-	1,000	6,000	-	-	-	-	-	-	-	7,000
Colony Court	100	3,100	-	-	-	-	-	-	-	-	3,200
Brockville	-	1,500	3,350	-	-	-	-	-	-	-	4,850
SMOC/Coventry Consolidated Facility	-	25	-	-	-	-	9,000	19,000	2,800	-	30,825
Kelfield	-	1,000	4,700	1,100	-	-	-	-	-	-	6,800
Kennedy	-	-	-	9,200	8,000	4,500	-	-	-	-	21,700
Oshawa	-	-	-	-	-	-	-	-	-	100	100
Peterborough	-	-	1,000	3,450	-	-	-	-	-	-	4,450
Station B	-	5,000	1,500	-	-	-	-	-	-	-	6,500
Thorold	-	-	-	-	-	-	200	5,800	-	-	6,000
TOC EMEC Expansion	50	50	3,500	-	-	-	-	-	-	-	3,600
VPC	2,630	4,950	7,250	4,500	-	10,000	10,000	-	-	-	39,330
Building Systems Program	1,831	1,863	1,895	1,928	1,961	1,995	2,030	2,065	2,100	2,137	19,805
Cabling	102	103	105	107	109	111	113	115	117	119	1,100
EGD Targeted GHG & Energy Reductions	350	350	350	-	-	-	-	-	-	-	1,050
Furniture and Ergonomics	203	207	211	214	218	222	226	229	233	237	2,201
Direct Capital Overheads	530	530	530	250	250	250	250	175	-	-	2,765
REWS Total	5,796	19,678	30,891	22,349	10,538	17,078	21,818	27,384	5,251	2,593	163,376

Table 7: Fleet and Equipment Capital Summary ($ Thousands)

Program/Project Name	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	10-year Forecast
Light & Medium Duty Vehicles	5,069	4,903	5,051	4,652	4,871	4,586	4,495	4,636	4,636	4,636	47,533
NG Conversion Kits for New Fleet Vehicles	400	408	416	424	432	586	535	546	557	-	4,304
Heavy Equipment	500	500	500	500	454	741	622	636	636	636	5,725
Tools	800	800	800	1,000	1,000	1,000	1,000	1,000	1,000	1,000	9,400
Fleet Assets Total	**6,768**	**6,610**	**6,767**	**6,576**	**6,757**	**6,913**	**6,652**	**6,818**	**6,829**	**6,272**	**66,962**

Table 8: TIS Capital Summary ($ Thousands)

Asset subclass	Program/Project Name	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	10-Year Forecast
Hardware and Software	**CIS Replacement**	16,400	4,000	-	-	-	5,000	5,600	-	-	600	31,600
Software	**Customer Experience Transformation**	7,000	-	-	-	-	-	-	-	-	-	7,000
Hardware	**Hardware**	1,270	2,400	2,715	4,070	3,000	4,215	3,205	3,620	3,030	2,100	29,625
Software	**Software**	14,965	15,845	18,570	20,166	18,966	12,751	12,161	18,346	18,936	19,266	170,972
Communications	**Communication**	250	250	250	175	175	175	1,175	175	175	175	1,975
	TIS Total	**39,885**	**22,495**	**21,535**	**24,411**	**22,141**	**22,141**	**22,141**	**22,141**	**22,141**	**22,141**	**241,174**

Table 9: Business Development Capital Summary ($ Thousands)

Asset subclass	Program/Project Name	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	10-Year Forecast
Large and Utility Natural Gas for Transportation Stations (NGT)	NGT Maintenance	686	698	710	758	596	606	617	627	638	649	6,586
Small NGT Stations / Vehicle Refueling Appliance (VRA)	Rental VRAs	250	254	259	263	268	272	277	282	287	292	2,704
Large and Utility Natural Gas for Transportation Stations (NGT)	NGT Rental Compressors (Non-Transit)	2,600	5,600	4,500	3,000	3,000	3,000	3,000	3,000	3,000	3,000	33,700
Lower carbon strategies	Hydrogen Blending	1,200	365	-	-	-	-	-	-	-	-	1,565
	Business Development Total	**4,736**	**6,918**	**5,469**	**4,021**	**3,864**	**3,879**	**3,894**	**3,909**	**3,925**	**3,941**	**44,555**

ENBRIDGE GAS INC.
Answer to Interrogatory from
Board Staff (STAFF)

Reference: Exhibit C1/ Tab 1/ Schedule 1/Pg. 42, 43 and 49, and Exhibit C1/Tab 2/Schedule 1/Pg. 19

Question:

Enbridge Gas states that the asset categories are used by both Enbridge Gas Distribution and Union Gas to organize and define assets in the respective AMPs. The list of asset categories are provide in Table 3 of the USP. However, the asset classes provide on page 19 of the Enbridge Gas Distribution AMP are different from those identified in Table 3.

a) Please explain the reasons for the differences between the “asset categories” and “asset classes”. Where possible, please reconcile the differences.
b) Table 6 in the USP provides a list of potential ICM projects for both Enbridge Gas Distribution and Union Gas. The table also identifies the asset class, in-service year and capital costs. Does Enbridge Gas have a similar table for the base spend? If not, please provide a table showing the base spend in a similar format (if it is not onerous). Please also confirm that Enbridge Gas will be able to provide a similar table for the base spend in the next iteration of its AMP.

Response

a) The asset classes for the EGD rate zone and asset categories for the Union rate zones are essentially equivalent. The column headings for Table 3 provided below and found on page 43 in Exhibit C1, Tab1, Schedule1 has been updated to clearly identify the asset categories for the EGD and Union rate zones.

Union Gas	EGD
Pipelines	Pipe
Stations	Stations
Distribution / System Growth	Customer Growth
Measurement	*Contained within Storage, Stations, Customer Assets Asset Classes*
Contained within pipelines, stations, measurement asset categories	Customer Assets
Utilization	*Contained within Customer Assets Asset Classes*
Underground Storage	Storage
Compression and dehydration	*Contained within Storage Asset Class*
Liquid Natural Gas (LNG)	n/a
Corporate Real Estate (CRES)	Real Estate and Workplace Services
Fleet	Fleet and Equipment
Information Technology (IT)	TIS (Technology Information Services)
n/a	Business Development

b) A complete summary of all projects in the Enbridge Gas asset plan are included in Exhibit I.BOMA.22. The projects and programs greater than $2M that are part of the 2019 capital budget of each utility system plan are included in Exhibit C:

- EGD rate zone AMP: Appendix 7. 2-1 to Appendix 7.2-9.
- Union rate zones AMP: Appendix D.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Board Staff (STAFF)

Reference: Exhibit C1/ Tab 2/ Schedule 1,Table 3.3-2: “Maturity Level Definitions”, Figure 3.3-1: EGD’s ISO5500X Maturity Assessment – Current (Performed by KPMG) p 58.

Question:

Based on KPMG’s assessment, Enbridge Gas Distribution’s Asset Management Program is operating primarily within the *Proactive* and *Managed* levels of maturity, as seen in **Figure 3.3-1.”**

Maturity Level				
0 (Aware)	1 (Reactive)	2 (Proactive)	3 (Managed)	4 (Leading Practice)
The organization has no / inadequate process(es) in place for asset management.	The organization has identified the need for asset management, and there is evidence of intent to progress it. Policies may be in place, that need updating	The organization has developed an action plan to systematically and consistently achieve asset management requirements, and can demonstrate that these are being progressed with credible and resourced plans in place. There is documentation in place for major processes but no set plans for continual improvement and change management.	The organization has a well-documented asset management program set to systematically and consistently achieve its goals. Documentation outlines an approved process for change management, updating documents and processes, and continual improvement.	The organization's process(es) surpass the standard required to comply with ISO55000x requirements.

Table 3.3-2: "Maturity Level Definitions

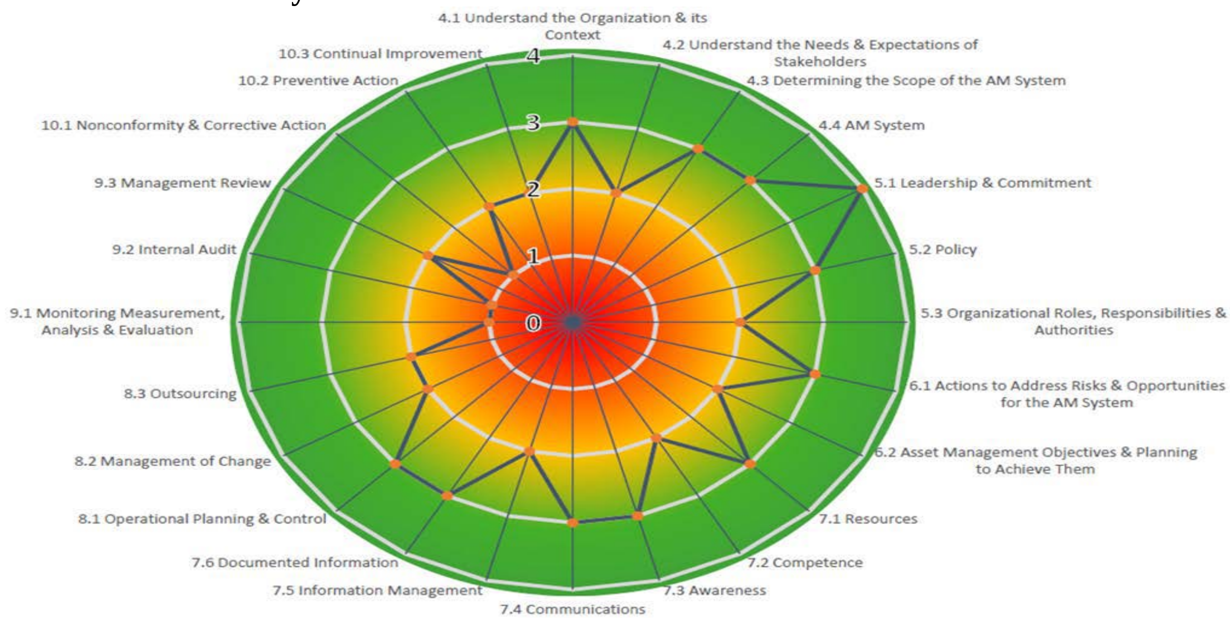

Figure 3.3-1: EGD's ISO5500X Maturity Assessment – Current (Performed by KPMG)

The statement on pg. 58 could be interpreted as Enbridge Gas being between the 2 and 3 level of maturity. Please confirm that this is an accurate interpretation. Also, please confirm that this determination included comparison against the peers in the industry similar to Enbridge Gas and if, so, please confirm that these companies included some at Maturity Levels 3 and 4 where industry best practices would be expected to be evident?

Response

Confirmed. The statement 'Enbridge Gas Distribution's Asset Management Program is operating primarily within the Proactive and Managed levels of maturity' can be interpreted as the EGD rate zone's AMP being between the 2 and 3 level of maturity.

In performing the Asset Management Assessment, legacy EGD evaluated policies, practices and processes against the ISO 5500x framework. Industry practices at peer utilities were taken into account as part of this assessment.

In legacy EGD's work with KPMG, it was found that peer organizations also had a combination of *Proactive*, *Managed* and *Leading Practices* for ISO components within their asset management environment. Some organizations in the United States and

Europe were leading in certain areas as they initiated asset management programs earlier than legacy EGD due to a regulatory or other requirements. It is Enbridge Gas's intention and strategy to progress to being between *Managed* and *Leading Practice* in all components of the ISO framework.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Board Staff (STAFF)

Reference: Exhibit C1/ Tab 2/ Schedule 1, pg. 63

Question:

The Enbridge Enterprise Strategic Priorities (**Section 2.2.4**) sets the foundation for all company-wide operations and initiatives. The Asset Management Policy (**Section 4.1.2**) translates the Enterprise Strategic Priorities into the application of asset management at Enbridge Gas Distribution and outlines the high-level goals and principles used to manage assets. Asset Management Strategies (**Section 4.1.3**) supports the policy, and outlines the methods employed for asset management success. Lastly, the Asset Management Core Process (**Section 4.2**) outlines how the identified strategies will be executed.

The alignment of Asset Management Strategies to the Enterprise Strategic Priorities is summarized in **Section 4.1.4**.

Please explain the reason(s) for the asset management policy and asset management strategy being integrated into the same document as the AMP? Generally, accepted best practices asset management policy and strategy could be part of a set of "higher-tier" corporate governance documents which reflect senior management commitments and expectations providing authority to lower tier documents such as the AMP. Are the asset management policy and strategy part of such higher–tier corporate governance or other documentation? If so, please confirm this and identify the "higher-tier" documents.

Response

In designing its AMP, legacy EGD chose to consolidate all Asset Management material into one document to ensure complete line of sight from enterprise priorities down to asset level strategies. Please refer to Figure 1.2-1 for an illustration of the EGD rate zone's Asset Management structure[1]

The preliminary sections of the AMP document (Sections 2, 3, and 4) reflect EGD's "SAMP", which ISO defines as the content that "details the asset management objectives, explains their relationship to the organizational objectives and the framework

[1] Exhibit C1, Tab 2, Schedule 1, page.16.

required to achieve the asset management objectives"[2]. EGD has chosen different titles, which is acceptable by ISO; *"NOTE: A SAMP can be referred to by other names, e.g. "asset management strategy".*[3]

"While it is necessary to distinguish between the SAMP and the asset management plan(s), it is not a requirement of ISO 55001 to create separate pieces of documented information for each".[4]

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[2] ISO 55002:2018, page. 18.
[3] Ibid.
[4] Ibid.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Board Staff (STAFF)

Reference: Exhibit C1/ Tab 2/ Schedule 1/ pg. 90 – Asset Information Management.

Question:

Asset data provides the foundation for asset life cycle decision-making, as outlined in Asset Management Strategies (Section 4.1.3). Asset data exists in both structured (from databases residing within information systems), and unstructured (on paper and scanned) forms. Asset information derived from these sources, supported by company and industry knowledge, is leveraged for asset analysis and modeling to:

- Understand condition and predict risk
- Support risk and opportunity assessments
- Inform and support asset health reviews and Engineering Reliability Assessments
- Establish asset inventory and population over time
- Ensure compliance with company policy and regulatory requirements
- Make operational asset decisions, e.g. emergency response
- Ensure safe and reliable operations e.g. core work, maintenance

With the company's growing focus on asset, integrity, and process safety management, there is a need for various groups in Operations, Integrity, and Asset Management to perform analyses based on a common understanding of hazards, asset master data, and a current understanding of the asset condition. Tools and methods to collect, store, manage, and use this data in a consistent and repeatable way are described in Table 4.2-3."

a) The company has indicated that one of the objectives for asset analysis and modeling is to establish asset inventory and population over time. What is the degree of completion of the asset inventory?
b) For the assets in (a) above, what percentage of assets have undergone asset condition assessment?

Response

a) Asset Classes and Sub-classes are defined in Asset Plan and there is an inventory of the gas-carrying assets, fleet, real estate, and physical IT Assets. These exist in various systems in the organization but there is only one system of record for any particular asset or sub-asset as defined in the asset plan. In some cases, the inventory is derived from attributes of the asset (for example valve or regulator type, installation date). To the extent that this information is missing or inaccurate, there is an ongoing effort to confirm the inventory of that asset sub-class. A visual representation of each asset class as well as the current asset inventory is included for each of the 9 asset classes in the EGD rate zone's AMP.[1]

b) Some assets can be directly assessed in terms of their condition (inline inspection of pipelines, direct inspection of stations). In other cases, no direct condition assessment can be completed because the assets are below grade.

[1] Exhibit C1, Tab 2, Schedule 1, page 105.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Board Staff (STAFF)

Reference: Exhibit C1/ Tab 2/ Schedule 1/ pg. 93 – Probability of Failure and Asset Health Indices

Question:

With respect to asset analytics, Enbridge Gas Distribution has noted that for some asset classes, historic failure data can be combined with structured tacit knowledge and statistical methods to establish a probability of failure based on age and other statistically significant factors. The probability of failure is used to establish an Asset Health Index – a measure of the current health of the asset population and its expected deterioration.

a) Please provide a list of the asset classes for which health indices are available?
b) Please provide an outline of a process describing how the health indices were arrived at and how the health data is combined with maintenance data to determine asset replacement rates?

Response

a) The 2017 Asset Health Review has asset health indices for the following assets and components.

Asset Class	Asset Category	Asset Sub-Class
Pipes	Distribution Mains	Steel Mains
		Pre-1977 PE Mains
		1977 to 1985 PE Mains
		Post 1985 PE Mains
	Services	Steel Services
		Pre-1977 PE Services
		1977 to 1985 PE Services
		Post 1985 PE Services
	Risers	Steel Risers
		Copper Risers (AMP Fittings)
		PE Risers
		Anodeless Risers
	Mainline Valves (>= NPS 4)	Ball Valves
		Gate Valves
		Plug Valves
		Unknown Type Valves
Stations	District Stations	Station Valve Systems
		Station Regulators
	Header Stations	Station Valve Systems
		Station Regulators
	Sales Stations	Station Valve Systems
		Station Regulators
Storage	Compressor Stations	Compressors
		Crank Assemblies
		Engines
		Foundations
		Aftercoolers
		Heating & Cooling System
		Valve System
	Valves	Station Valves
		Pool Valves
		Pipeline Valves

b) Asset Health Indices are used to score or rate the condition of an asset by incorporating a method to measure the progress of degradation leading to failures (for example those that result from corrosion). Structured tacit knowledge is combined with maintenance and failure data and asset management system to establish a probability (or intensity) of failure curve for each asset or component in the population. An example of relevant tacit knowledge is the significance of good annual cathodic protection readings on a steel pipeline system.

Statistical tools such as SAS and ReliaSoft are used to support this work.

A reliability curve can be developed for each asset or component in the gas distribution system using failure and asset data for the population as a whole. If the tacit knowledge referenced above is available for particular assets, it can be used to adjust the reliability curve to reflect that knowledge.

Reliability engineering applies statistical techniques to calculate the probability of failure for individual assets. An Asset Health Index ("AHI") is the quantification of a calculated condition assessment using reliability engineering to determine the condition of an asset relative to its end of life for non-repairable assets, or its next expected failure for repairable assets.

The AHI methodology provides a high level 10-year overview of the failure probability of asset types. The AHI takes the 10-year average of an asset's probability of failure and classifies the asset into a grouping which showcases the expected time span of its failure. The AHI incorporates an asset's current day probability of failure and the degradation of that asset averaged over a 10-year period.

The table below describes the AHI categories for Pipe, and Station gas carrying assets based on years.

Health Index Category	Time to First or Next Failure
HI1	Greater than 40 years
HI2	Within 40 years
HI3	Within 25 years
HI4	Within 10 years
HI5	Within 5 years

The Storage Health Index ("SHI") method shown in the table below also incorporates probability of failure, however instead of using the age parameter, it uses run time. The five categories were established to closely represent a typical year based on 2,000 run hours per year.

HEALTH INDEX CATEGORY	TIME TO NEXT FAILURE
SHI1	Greater than 10,000 run hours
SHI2	Within 10,000 run hours
SHI3	Within 5,000 run hours
SHI4	Within 3,000 run hours
SHI5	Within 2,200 run hours

As shown in Exhibit C1, Tab 2, Schedule 1, page 70, lifecycle strategies and replacement rates are derived from a number of factors such as the AHI, observed condition, risk, operability, maintainability, obsolescence, and historical failure rates.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Board Staff (STAFF)

Reference: AMP – Exhibit C1/Tab 2/Schedule 1/Pg.99 and Asset Management Plan (EB-2012-0459, Exhibit B2/Tab 10/Schedule 1/Pg.35)

Question:

In 2013, Enbridge Gas Distribution filed an Asset Management Plan (AMP) with the OEB for the first time as part of its Customer IR filing (EB-2012-0459). In that AMP average customer growth for the period 2018 to 2022 was forecasted at an average rate of 40,000 per year. In the current AMP the average customer growth between 2018 and 2028 has been forecasted at approximately 30,000 per year. The table below compares the Customer Growth Capital Costs for the period 2019 to 2022 based on the two Asset Management Plan

Customer Growth Capital Costs ($000)	2019	2020	2021	2022
AMP – EB-2012-0459	105,956	108,137	110,324	112,966
AMP – EB-2018-0305	98,835	102,530	104,681	103,585

a) Please explain how the 25% reduction in customer growth has impacted the customer growth related capital expenditure forecast for the period 2019 to 2028.
b) Based on the table above, there is a minimal reduction in customer growth related capital costs between the two AMPs. Considering the significant reduction in customer growth forecast between the two AMPs, why is there no corresponding reduction in capital costs?

How has the change in the Customer Connection Policy of Enbridge Gas that requires every new customer to meet a PI of 1.0 and pay a capital contribution if required, impacted the capital expenditure forecast for the period 2019 to 2023.

Response

The customer growth related capital expenditure for the period 2019-2028 was determined using the most up to date customer growth forecasts and the most recent historical costs. This is further explained in section 5.5, under the methodology heading:

> One of the key drivers of Customer Growth capital requirements is the historical spend profile in each area. **Capital spend is not uniform across all areas, as some areas have inherently higher costs (e.g., hard rock, type of joint trench agreements, densely populated areas, and type of customers predominantly being attached). Based on the historical spend in each area containing unique characteristics, combined with forecast customer additions and inflation, the 10-year capital expenditure forecast was determined**. The capital requirement includes an allowance for some localized main extensions and operational considerations.[1]

Other capital considerations that impact the capital costs for customer additions are included in section 5 of the Asset Plan.[2] Some of the key cost impacts discussed in this reference are:

- Increased need for hydrovac in working around live gas facilities
- Increased winter construction resulting in higher construction costs (winter premium)
- Increased municipal and conservation authority requirements (increased trenchless technologies)
- Increased apartment apartments/condominiums due to urban density have been accounting for a larger share of total housing starts, and one building counts as a single customer addition.

As discussed above, the customer growth related capital expenditure was determined using the most up to date forecasts. Any impacts accruing to Enbridge Gas Distribution's refinement in 2015 of its cost estimation approach for residential infill customers is reflected in the net historical costs. Therefore, the change in the Customer Connection Policy has been included in the estimate.

[1] Exhibit C1, Tab 2, Schedule 1, pages 102-103.
[2] Ibid.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Board Staff (STAFF)

Reference: AMP – Exhibit C1/Tab 2/Schedule 1/Pg.121

Question:

Enbridge Gas has noted that the number of leaks on steel mains have been on an upward trend over the last 11 years. Figure 5.2-11 provides the number of leaks on steel mains from 2007 to 2017.

a) The number of leaks has increase significantly from 2013 to 2017. Does Enbridge Gas have an estimate of how much natural gas has escaped as a result of these leaks?
b) What is the contribution of leaks on steel mains to Unaccounted for Gas over the past four years?

Response

a) Natural gas loss is estimated at the distribution system level and not specifically reported on steel mains gas leaks.

b) Unaccounted for Gas (“UAF”) is reported at the distribution system level. The UAF captures the total gas loss from the system, but it does not differentiate gas leaks from other types of gas loss. Therefore steel main leaks are included in the UAF but not specifically quantified.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Board Staff (STAFF)

Reference: Exhibit C1/ Tab 2/ Schedule 1/ pg.122 and 131

Question:

The evidence indicates that Enbridge Gas Distribution is engaged in a comprehensive, on-going program to measure, quantify and take remedial action to preserve the integrity of its steel mains.
However, according to Enbridge Gas Distribution's analytical models, the projected rate of increase of leaks in its steel pipe is forecasted to grow "exponentially" over the next 40 years (Figure 5.2-13: Steel Mains Leak Projections (2017 – 2057).

a) Is Enbridge Gas anticipating having to commit significantly more financial resources per year to adequately fund the steel main repair/replacement program based on the potential to increase its nominal replacement rate from 9km/year to a higher number (e.g. 18km/year) to align with the "100 years of age" criterion that is noted? If this is the case, when will this higher level of expenditure begin and what is the forecasted magnitude of the increase?
b) Does Union Gas have similar issues? Is Enbridge Gas participating with industry bodies such as the CSA Z662 standards committee and the applicable American Gas Association and Canadian Gas Association committees to address this issue?
c) Is the Enbridge Gas Distribution Steel Main Leak Analytical Model(s) unique to Enbridge Gas Distribution or is it based on an "industry standard" that it applies to its unique pipeline integrity data?
d) Does Union Gas have similar leak forecast data as Enbridge Gas Distribution put forward in Figure 5.2-13: Steel Mains Leak Projections (2017 – 2057)? If yes, please provide the data and a graphical representation.
e) Will Enbridge Gas provide a similar level of detail as Enbridge Gas Distribution when it submits the integrated AMP?

Response

a) Yes, Enbridge Gas expects a significant increase in its level of spend to adequately manage the lifecycle of steel mains. As outlined in the EGD rate zone AMP:

> At the current rate of replacement (approximately nine kilometers per year) it would take over 200 years to address 2,200 kilometers of 1950s pipe alone. The potential volume of leaks associated with the increasing amount of pipe over 100 years in age could eventually compromise EGD's ability to maintain a safe and reliable distribution system; depending on the timing and annual rate of replacement, EGD's ability to respond to leaks will be impacted. EGD will continue to refine its Distribution Steel Mains Replacement Strategy to manage this aging asset population based on advancements in the understanding of leak projections, asset age limit, and resource capacity.[1]

The NPS 30 Don Valley crossing, Windsor Line and London Line replacement projects are examples of some priority replacements that Enbridge Gas is advancing in the near term based on known asset condition and risk results.

b) The Enbridge Gas combined asset base will be evaluated to determine if there are similar issues with the Union rate zone assets.

Yes, Enbridge Gas is currently participating in the CSA and AGA forums and conferences.

c) Statistical models are developed internally using failure data. Currently there is no industry standard, i.e. similar to the CSA Z662, for leak analytical models. However, the methodology is considered to be an industry methodology that is currently used in Europe. Based on the company knowledge from the AGA, CSA and GTI industry committees, Enbridge Gas is the first North American company to use this form of predictive analytics. Recently, several other companies have indicated adoption of a similar approach.

d) No, leak projection data is not available for the Union rate zone assets.

e) Enbridge Gas will assess the data availability and compatibility of the combined assets to determine the appropriate level of detail to provide in the integrated AMP.

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[1] Exhibit C1, Tab 2, Schedule 1, page 131.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Board Staff (STAFF)

Reference: AMP – Exhibit C1/Tab 2/Schedule 1/Pg.140

Question:

Isolated steel services are a small population of steel services (numbering approximately 2,200) that are disconnected from the cathodic protection of the original parent steel main. This occurs when poorly performing steel mains are replaced with plastic mains and existing steel services are reconnected to the plastic mains, isolating the services from the cathodic protection received through the original steel main. To remain cathodically protected, these isolated assets are reliant on their coatings and localized anode protection systems. Over time, these localized, sacrificial anodes degrade and no longer protect the service. The lack of cathodic protection over time, coupled with poor coating condition and environmental stressers causes accelerated degradation of isolated steel services and results in accelerated corrosion growth, which can ultimately lead to failure and loss of containment.

a) Has Enbridge Gas considered any other approach apart from replacing poor performing steel mains with plastic mains?
b) What measures has Enbridge Gas taken to slow down or delay the rapid degradation of isolated steel services and accelerated corrosion growth?

Response

a) Yes, Enbridge Gas has considered other approaches to manage steel mains, such as using cathodic protection system to prevent corrosion when appropriate.

b) Enbridge Gas will continue to identify isolated steel services in the system. For the isolated steel services in good condition, cathodic protection could be added to prevent accelerated corrosion. If an isolated steel service is discovered in poor condition, it would be more appropriate to replace it with a plastic service.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Board Staff (STAFF)

Reference: AMP – Exhibit C1/Tab 2/Schedule 1/Pg.140

Question:

Pre-1977 plastic services refer to Aldyl A vintage plastic using early manufactured resins. These services range in age from 41 to 50 years, and account for 4% of the total services (approximately 84,000). Though Aldyl A services are not subject to the same stressors as Aldyl A mains, their failure modes are identical, with consequences more severe than the typical pinhole failure of steel services. Cracking failures have higher consequences, as sudden cracking produces a higher volume of natural gas released compared to pinhole failures due to corrosion observed in steel services. The GTI study identified that the remaining life of Aldyl A varies between 10 and 50 years. It is expected that when failures do occur, the rapid degradation of Aldyl A services may prove difficult to manage. Further studies are required to identify which stress intensifiers are applicable in the Enbridge Gas Distribution network and how the combined effect of environmental factors affect Aldyl A useful life.

a) Has Enbridge Gas Distribution experienced any failures of Aldyl A services? If yes, please provide details, impacts and number of occurrences.
b) Are there any solutions to prevent the rapid degradation of Aldyl A services?
c) Enbridge Gas Distribution has noted that further studies are required to identify which stress intensifiers are applicable in the distribution network and how the combined effect of environmental factors affect Aldyl A useful life. When are the further studies expected to be completed and will this issue be addressed in the next AMP?

Response

a) 106 failures have been recorded between 2007 and 2017. There is an ongoing effort to review and understand the failure mechanism. The impact of a service leak is summarized in table 1.8.2 in the Risk/Opportunity column.[1]

[1] Exhibit C1, Tab 2, Schedule 1, page 21.

b) No, the rapid degradation of Aldyl A plastic pipe is a material property that is highly dependent on temperature and total hoop stress of the pipe.

c) Further study on vintage plastic mains is expected to be completed in the next 5 years.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Board Staff (STAFF)

Reference: AMP – Exhibit C1/Tab 2/Schedule 1/Pgs. 146-154

Question:

The evidence notes that the most vulnerable risers in the system are copper (AMP) risers which make up approximately 14% of the overall population (approximately 285,000 units), and are subjected to an erosion corrosion method of internal degradation, resulting in either pinholes or cracks. The condition of copper risers is expected to significantly degrade over time with the expected yearly increase in the number of leaks over the next ten years. The current proactive replacement program replaces 4,000 copper risers per year.

a) What would be the total cost of replacing all copper risers within the next two decades?
b) Has Enbridge Gas Distribution estimated the volume of natural gas lost as a result of leaks or cracks in copper risers? Please provide a detailed response.

Response

a) Using the estimated average unit cost from the program, excluding future inflation and other potential cost changes, the high-level estimate to replace all copper risers within the next two decades is approximately $337 million.

b) Natural gas loss is estimated at the distribution system level and not specifically reported on copper riser leaks.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Board Staff (STAFF)

Reference: AMP – Exhibit C1/Tab 2/Schedule 1/Pg.158

Question:

Fibre optic monitoring is a key initiative for installation along new construction pipelines. Fibre optic sensing systems operate and serve up information in real time. Incident response capacity and quality is superior to the current practice. Enbridge Gas Distribution has indicated that fibre optic monitoring will allow it to detect and quickly respond to unauthorized third party activity or intrusions. Enbridge Gas Distribution will also have the ability to pinpoint leak locations, improving public safety and reliability.

a) What is the total spend on fibre optic monitoring to-date?
b) What percentage of the pipelines are currently being monitored using fibre optic monitoring?
c) What percentage of the total pipeline does Enbridge Gas Distribution target for installation of fibre optic monitoring?
d) Does the Union Gas rate zone also use fibre optic monitoring on key pipelines?

Response

a) The total spend on fibre optic monitoring to-date is $0.9 million.

b) The percentage of the pipelines that are currently being monitored using fibre optic monitoring is less than one percent.

c) The percentage of total pipeline targeted in the EGD rate zone for installation of fibre optic monitoring is less than ten percent. Installation of fibre optic monitoring is intended for use on key pipelines operating at 20% – 30% Specified Maximum Yield Stress (SMYS), and greater than 30% SMYS.

d) The Union Gas rate zone does not use fibre optic monitoring on key pipelines.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Board Staff (STAFF)

Reference: AMP - Exhibit C1/Tab 2/ Schedule 1/ pg.166

Question:

The Telemetry System components connect station components to a network that remotely transmits station performance information to Enbridge Gas' Gas Control group in Edmonton.

a) Will Enbridge Gas operate one gas control centre for Enbridge Gas Distribution and Union Gas? If no, why not? If there will be one gas control centre, where will it be located?
b) What gas control efficiencies does Enbridge Gas expect as a result of integration?

Response

a) Enbridge Gas will operate one gas control centre for Enbridge Gas Distribution and Union Gas. It will be located in Chatham, ON.

b) Enbridge Gas is in the very early stages of integration. However, as per the response provided to part a), there is an expectation that there will be some cost savings associated with gas control.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Board Staff (STAFF)

Reference: AMP – Exhibit C1/Tab 2/Schedule 1/Pg.234

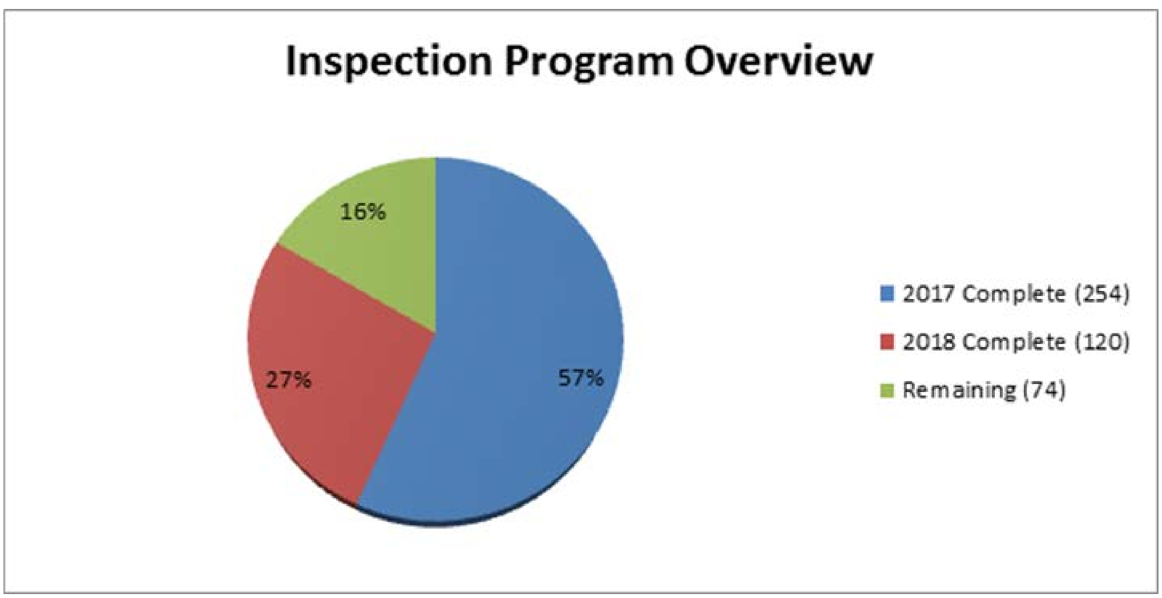
Question:

With respect to storage assets, Enbridge Gas has indicated that the understanding of the current state and condition of the filters, separators, and tanks is based on Subject Matter Advisors input and supported by the in-progress pressure valve and tank inspection program that is under development. Condition assessment of filters, separators, and tanks are currently underway.

Please provide an update on the condition assessment of filters, separators and tanks. If the assessment is complete, please provide the results.

Response

Current status of the Pressure Vessel and Inspection Program is summarized in the following chart.



Summary of findings to date have been categorized as “red” (immediate concerns that have already been or are in the process of being resolved), “yellow” (concerns requiring repairs, and/or more frequent inspection), and “green” (items with no major concerns).

Red:

- Chatham D: S_CHT-543-T-111 – full through failure of waste fluids tank
- Crowland: S_CRW-543-T-104 – secondary containment failure
- Corunna Comp Station: Glycol piping between glycol vessels, extremely thin wall
- Corunna Comp Station: Drain piping from separator sump with extremely thin wall
- Corunna Comp Station: Cracked sight glasses replaced

Yellow

- Crowland: S_CRW-543-T-103 – secondary containment integrity concern

Green

- All remaining inspected vessels and tanks

ENBRIDGE GAS INC.
Answer to Interrogatory from
Board Staff (STAFF)

Reference: AMP – Exhibit C1/Tab 2/Schedule 1/Pgs. 243-253

Question:

Enbridge Gas has several storage wells. Additional reservoirs have been added to the Gas Storage Operation either by acquisition (Chatham D) or operating agreement (Crowland). Enbridge Gas has identified several maintenance and replacement issues with respect to storage operations including gas compressors for storage, yard auxiliary systems, yard valves and actuators, metering system, flow control systems, dehydrators, incinerators, filters, separators, tanks, pipelines, wells and master valves. The total capital spend for storage is estimated to be $180 million for the 10-year period (2019 to 2028).

a) Has Enbridge Gas considered reducing the number of wells or abandon a portion of its storage assets in order to reduce capital spending considering that it now has access to the large storage pool of Union Gas?
b) Enbridge Gas has indicated that most wells at Crowland do not possess a suitable master valve and wellhead, and have only two casings. Many Crowland wells are re-lined, further justifying replacement. Replacement of well assets, especially at Crowland, is expected to be a significant capital request within the scope of the 10-year Asset Management Plan. Since Crowland has an operating agreement, why has Enbridge Gas not considered abandoning this facility?
c) What is the total capital expenditure on the Crowland storage facility for the planned period (2019 to 2028)?
d) Please provide the cost of abandoning the Crowland facility and the associated savings in avoided capital and operating costs?

Response

a) Enbridge Gas has been operating as an amalgamated entity for only four months and is not in a position to provide estimates of optimization or integration savings.

b) As described in the response to Exhibit I.STAFF.32, the major capital expenditures identified in the respective AMPs are considered to be essential expenditures. Additional analyses, considering the now-combined storage assets, of various options to manage Crowland are currently underway. Once the optimal solution is confirmed, the asset management plan will be updated accordingly.

c) Execution of the proposed well and field line work at Crowland is currently planned for 2024 to 2026 in the AMP. The estimated costs for the well and field lines is $11,648,000 and $3,457,000 respectively and is included in Exhibit C1, Tab 2, Schedule 1, page 1181 to 1185, 1196 to 1200. 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.

d) Additional analyses of various options to manage Crowland are currently underway.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Board Staff (STAFF)

Reference: AMP - Exh. C1/Tab 2/ Schedule 1/ pgs. 252-253 and Exh. C1/ Tab 3/Schedule 1/pg. 99

Question:

The total spending on Storage is estimated at $180 million from 2019 to 2028 for Enbridge Gas Distribution and $17.9 million for Union Gas.

a) What storage optimization benefits does Enbridge Gas expect to achieve as a result of operating the Enbridge Gas Distribution and Union Gas storage operations on an integrated basis?
b) What benefits would be achieved by deferring all but essential major storage capital and operating and maintenance expenditures until the Enbridge Gas Distribution and Union Gas AMPs are fully integrated?

Response

a) Enbridge Gas has been operating as an amalgamated entity for only four months and is not in a position to provide any estimates of optimization or integration savings.

b) Please see Exhibit I.STAFF.32, part b.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Board Staff (STAFF)

Reference: AMP - Exhibit C1/Tab 2/ Schedule 1/ pg.356

Question:

Enbridge Gas Distribution's Customer Experience Transformation project consists of initiatives that span multiple Customer Information System asset subclasses. The proposed two year project proactively transforms the way Enbridge Gas Distribution does business with its customers to make customer interactions easier. The project is estimated to provide Enbridge Gas Distribution with O&M savings of approximately $13 million annually. In Year 1 Enbridge Gas Distribution has provided a list of activities that it plans to undertake, one of which is to leverage analytics and Artificial Intelligence (AI) to improve bill estimation.

a) Please provide additional information on how Enbridge Gas Distribution intends to leverage analytics and AI to improve bill estimation.
b) What is the total cost of the Customer Experience Transformation project?
c) Enbridge Gas Distribution has identified O&M savings of $13 million annually. When will Enbridge Gas realize these savings?
d) Does Enbridge Gas intend to implement a similar project for the Union Gas rate zone? Please elaborate on the response.
e) Is Enbridge Gas' intent to use AI in its operations over and above its intent to leverage analytics and AI to improve bill estimation?
f) What other AI activities does Enbridge Gas plan to pursue and when? What productivity improvements does Enbridge Gas expect for each AI activity?

Response

a) From an analytics perspective the intent is to better use the entire history of consumption and weather (degree day) data available for each premise/account to calculate estimation factors. The methodology previously configured in SAP does not use the entire history of data available and results in changes in estimation factors which could cause inconsistency. From an AI perspective, the intent is to adjust estimation factors more quickly based on changes in consumption patterns. A simplistic example would be a customer replacing their furnace resulting in a decrease in natural gas consumption. Employment of AI would enable identification of these changes in consumption more quickly resulting in more accurate bill estimation.

b) Total capital spend on the program over 2017/2018 was $17.5 million. Additional costs not capitalized (design, analytics, change management, training) totalled $4.6 million. The forecasted capital spend for 2019 is $7.0 million.

c) Savings from the program were identified in two key areas: reduced operating costs under the Customer Care Services Agreement (CCSA) with Accenture and increased electronic billing adoption. The savings anticipated in the original business case are being realized.

d) Enbridge Gas is in the initial stages of integration and has not made any decisions on timing regarding projects related to customer self-service.

e) Yes, the intent is to use AI in customer care operations over and above bill estimation.

f) The intent is to pursue AI activities that allow for proactive anticipation and handling of customer issues. The ultimate goal in these types of activities is to eliminate live agent interactions and drive down the total cost-to-serve. Reducing call volumes and handle time results in direct improvements in productivity. The most common use of AI in customer service is through introducing new channel options like a Virtual Assistant (Chatbot). Enbridge Gas has plans to launch a web-based virtual assistant in Q3 2019. Issue or call prediction is another example where AI can improve productivity in a few different ways including:

- proactively offering a self-service transaction to the customer through the myAccount channel;
- containing the inquiry in our Interactive Voice Response system; or
- routing the inquiry to the agent best equipped to handle the nature of the inquiry.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Board Staff (STAFF)

Reference: AMP – Exhibit C1/Tab 2/Schedule 1/Pgs.364-374

Question:

Enbridge Gas has provided information about its Natural Gas for Transportation (NGT) program. Enbridge Gas promotes the use of natural gas to these customers as an alternate fuel source to provide a lower cost and lower emission fueling solution for vehicles such as garbage trucks, light duty vehicles, and transit buses. Enbridge Gas Distribution has two general categories for NGT station types: Large, Mobile and Utility NGT stations and Small NGT stations (also referred to as VRAs).
Enbridge Gas is continually working to promote and grow its NGT business. Business Development's Marketing Solutions team promotes the economic and environmental benefits of using natural gas as a vehicle fueling source through marketing opportunities such as trade shows, industry networking events, and approaching potential customers. Enbridge Gas' NGT station rental rate is based on a regulated rate of return with a Profitability Index of 1.0, with maintenance costs on a fully recoverable basis from the customer. Enbridge Gas currently services 201 external customers and 19 internal Enbridge Gas Distribution sites with NGT stations for fueling fleet.

a) Does Enbridge Gas consider NGT as a core natural gas distribution activity? What is the benefit to distribution ratepayers of the NGT business?
b) Has Enbridge Gas considered separating the NGT business as a non-utility business?
c) Please provide the total costs and revenues of the NGT business for 2017 and 2018.
d) Has Enbridge Gas lost business from external customers within the past three years due to the switch to electric and hybrid vehicles? If yes, please provide details.
e) Have any existing customers informed Enbridge Gas that they will be switching to electric or hybrid vehicles in the near future? If yes, please provide details.
f) How many full-time equivalents are dedicated to the operation and maintenance of the NGT business?
g) Please confirm that the total capital spend on the NGT program for the ten year forecast period is $43 million. What value will distribution ratepayers derive as a result of this capital spend?

Response

a) Enbridge Gas treats NGT as an ancillary service. This service is subject to imputed revenues in the event the program does not achieve the utility's allowed level of return on equity, subject to being attributed fully allocated cost.

b) Enbridge Gas is not proposing any change to the treatment of its NGT business at this time.

c) Please see the requested figures in the table below.

Year	2017	2018
NGT Revenues	$ 2,284,196	$ 2,624,418
NGT Costs	$ 1,097,599	$ 1,276,967

d) No, Enbridge Gas is not aware of losing NGT external customer business within the past three years as a result of customers switching from natural gas powered vehicles to electric or hybrid vehicles.

e) No, there have been no existing NGT customers that have notified the Company that they will be switching to electric or hybrid vehicles in the near future.

f) There were three full time equivalent employees supporting the operation and maintenance of the Enbridge Gas Distribution NGT program in 2018.

g) Confirmed, the Asset Management Plan includes total estimated capital spend for NGT Maintenance, Rental VRAs, and NGT Rental Compressors (Non-Transit) of approximately $43 million over the ten year forecast period from 2019 to 2028.[1]

Ratepayers benefit from having the potential to participate in the sharing of NGT program earnings above the utility's regulated rate of return by way of earnings sharing. Ratepayers also benefit from having access to lower cost, lower CO2 emitting vehicle fuel and reduced CO2 emissions originating in Ontario. Further, these initiatives are consistent with and supported by the provincial governments "A Made-in-Ontario Environment Plan" (pages 33 and 34).

[1] Exhibit C1, Tab 2, Schedule 1, page 374.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Board Staff (STAFF)

Reference: AMP – Exhibit C1/Tab 2/Schedule 1/Pgs. 375-377

Question:

Enbridge Gas has indicated that it is eligible to request rate recoveries for qualifying incremental capital investments over and above the calculated materiality threshold through the OEB's ICM. The applicant has provided a list of ICM eligible projects in Table 6.1-3. Some of the specific projects are listed below.

Project Name	**In Service Year**	**Total In-Service Capital ($ million)**
Kennedy Road Expansion	2022	$21.7
NPS 12 Martin Grove Rd. Main Replacement – Phase 2	2024	$11.8
VPC Core and Shell Obsolescence	2025	$20.0

a) Is it the understanding of Enbridge Gas that any capital spending above the materiality threshold is eligible for ICM funding?
b) In the Toronto Hydro Electric Systems Ltd.'s three year application for 2012 to 2014 rates (EB-2012-0064), the OEB in its decision regarding the application for ICM funding noted, "the Board does not expect that projects that are minor expenditures in comparison to the overall budget should be considered eligible for ICM treatment. A certain degree of project expenditure over and above the threshold calculation is expected to be absorbed within the total capital budget." (pgs.18-19) Please provide the proportion of each individual project noted above to the overall capital budget for the respective year.
c) Why is it not possible to absorb the costs of the projects noted above considering the quantum of the in-service capital, specifically the NPS 12 Martin Grove Rd Main Replacement?

Response

a) For a description of the criteria used to determine Enbridge Gas's ICM funding request for 2019, please refer to Exhibit B1, Tab 2, Schedule 1, page 8, Section 2.

b-c) Enbridge Gas is not seeking any relief for the projects specified in the question in 2019. Accordingly, Enbridge Gas declines to respond.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Board Staff (STAFF)

Reference: AMP – Exhibit C1/Tab 2/Schedule 1/Pg. 694-696

Question:

In the business case summary for the NPS 20 Don River Relocation there is $4 million budgeted as retirement cost in 2020.

Please provide details about the retirement cost and what are they related to?

Response

The $4 million in retirement costs is associated with abandoning the main that is being relocated for the project.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Board Staff (STAFF)

Reference: AMP – Exhibit C1/Tab 2/Schedule 1/Pgs. 713-748

Question:

The AMP provides information and costing for the replacement of pre-1977 plastic mains. The strategy is to increase the replacement rate to approximately 10 km per year over the next ten years. The cost for 2020 replacement is $2.3 million and then increases every year until 2028 when the cost is $10.6 million.

Please explain the reasons for the significant increase in costs considering that the length of replacement is fairly constant over the 2020 to 2028 period.

Response

The cost increase of the program corresponds to a gradual increase in the replacement length from approximately 2km/year to 10km/year over the ten year period.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Board Staff (STAFF)

Reference: AMP – Exhibit C1/Tab 2/Schedule 1/Pgs. 859-896

Question:

The AMP Fitting Replacement Program is a proactive replacement program to replace copper risers and the AMP fittings that transition plastic services to copper risers. Enbridge Gas intends to start with 4,000 units per year in 2019 and increasing to 20,000 units per year by 2026 and beyond.

a) Please provide details with respect to retirement costs that are referred to in the business case.
b) The retirement cost starts at $3.6 million in 2019, gradually increasing to $10.5 million in 2028. The retirement costs constitute 30% to 40% of the total capital costs. Please explain the relatively high amounts for retirement costs.

Response

a-b) The retirement cost listed for this program is an estimate of the cost to remove the copper risers to take them out of service, which entails the excavation of the riser, isolation and removal of the fitting. The cost of removing the copper riser is estimated to be approximately 30-40% of the total cost for a copper riser replacement. Enbridge Gas believes these retirement costs to be reasonable.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Board Staff (STAFF)

Reference: AMP – Exhibit C1/Tab 2/Schedule 1/Pgs. 964-965

Question:

The business case for the York Region Reinforcement does not provide the primary issue/concern. The Issue/Concern section is generic and does not explain why the York Region Reinforcement will be required and how the magnitude of the costs are justified.

Response

The York Region area is experiencing significant load growth, and the distribution system in the region will require additional infrastructure to support the forecasted growth. Regulator station inlet pressures at the Baseline and McCowan Station are low and indicate growth in the downstream system. This station is furthest from the Gate Stations feeding York Region and the supply to this area will need to be reinforced to sustain growth in the downstream systems. Historical pressure data indicates that minimum pressures are being reached at the tag end of the system. System pressure and flow biasing is being used to ensure a predictable and reliable supply of gas to the Keswick area. The reduction in regulator station inlet pressure and the current flow biasing activities indicate an impending need to reinforce the system. Forecasting and pipeline modeling activities have indicated that customer growth will continue to increase demand on the system further reducing pressures.

There are a number of components to this reinforcement as detailed in the business case, those portions of the project that meet the criteria for a leave to construct will be filed at a future date.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Board Staff (STAFF)

Reference: AMP – Exhibit C1/Tab 2/Schedule 1/Pgs. 1026-1113

Question:

The District Station Rebuild Program strategy is to maintain a consistent operational reliability profile and requires the replacement of approximately 20 to 30 district stations per year. Each station in a given year will require a complete rebuild including the removal and replacement of the pressure control components, valves, associated piping and enclosure. Enbridge Gas has schedule one replacement in each year from 2019 to 2028.

a) In each of the years, the cost for the station rebuild includes $1.0 million in retirement costs. Please explain what the retirement costs are and what contributes to the quantum.
b) Is the $1.0 million an estimate for each of the years and what is the reason for the cost being the same in every year, from 2019 to 2028?

Response

a) Retirement costs are those incurred on removal, demolition and dismantling of existing station assets during the course of their retirement.

b) The $1.0 million retirement is an estimate for each year of the program. The estimate for each year is based on the combination of the number of sites planned and scope for each site. Please refer to the EGD rate zone AMP, Exhibit C1, Tab 2, Schedule 1, pages 192 to 193.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Board Staff (STAFF)

Reference: AMP – Exhibit C1/Tab 3/Schedule 1/Pgs. 20-21

Question:

Union Gas conducted Customer Engagement Research to explore the needs and preferences of customers regarding future initiatives to inform the organization's five year investment plans.

Please detail all changes that Union Gas made to the Asset Management Plan as a result of feedback from the Customer Engagement Research.

Response

Please see Exhibit I.STAFF.33.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Board Staff (STAFF)

Reference: AMP – Exhibit C1/Tab 3/Schedule 1/Pgs. 48-49

Question:

In 2002, Union Gas developed a software algorithm with the assistance of a third party consultant to aid in risk assessments for the pipelines greater than 30 percent Specified Minimum Yield Strength (SMYS). This software tool processed through an application called the Risk Analyst Tool, uses a number of probability and consequence factors to calculate a Total Risk Score for all pipelines greater than 30 percent SMYS within Union Gas' system. Moving forward, the Risk Analyst Tool will be used on an annual basis to generate updated asset health data for review and assessment.

Does Enbridge Gas intend to use the Risk Analyst Tool along with the software algorithm for assessing Enbridge Gas Distribution assets? If yes, would this require a change to the software algorithm?

Response

As Enbridge Gas progresses through integration, the Company will look at aligning risk methodologies. This includes examining the tools and techniques that have been used in the past at each company and how they might fit into the risk assessments that will be completed in the future. The goal is to determine the best overall risk approach. That process is in the early stages and no decision has been made on the use of the risk analyst tool.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Board Staff (STAFF)

Reference: AMP – Exhibit C1/Tab 3/Schedule 1/Pgs. 84-85

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. Spreading the verifications over several years will keep costs down and proactively implement an industry standard, which provides additional support for this program. Starting this program as forecast will mitigate the need for higher expenditures in a shorter time frame to meet these expected future mandated requirements.

a) Please provide the costs (capital and OM&A) of this program for the planned period.

b) The evidence states that the project will require a dedicated team to complete the verifications. How many FTEs and external resources will be required to implement this program?

c) MOP verification is not currently a requirement in Canada. Does Union Gas know when MOP verification will become a requirement in Canada? Is there a possibility that the MOP verification program could be different in Canada as compared to the United States?

d) The Customer Engagement Survey of Union Gas shows than 43% of those surveyed recommend waiting until the regulation is implemented in Canada. Why has Union Gas decided to implement this program when it is not a requirement in Canada and a large portion of its customers are recommending that they wait until the verification is required in Canada?

e) Union Gas has indicated that starting this program earlier will mitigate the need for higher expenditures in a shorter time frame to meet expected future mandated requirements. Union Gas has assumed that when Canadian authorities implement the regulations, they will not give companies enough time to implement this program. Why does Union Gas believe that Canadian authorities will not give companies sufficient time to implement the program when the regulations are put in place?

Response

a) For the OM&A and Capital costs please refer to Exhibit C1, Tab 3, Schedule 1, Table 5.4.1.4.1 on page 86, and Table 5.4.1.3.1 on page 82.

b) The expected FTEs required for this work is 10 in 2020, increasing to a total of 15 for years 2021 and beyond. These resources will be a mix of Enbridge Gas employees and contingent workers

c) No, Enbridge Gas does not know when MOP verification will become a requirement in Canada. It is unlikely the program would be substantially different than what is required in the United States, as the Engineering work required to verify a Pipeline MOP is not fundamentally different in Canada than it is in the United States.

d) While 43% of those surveyed in the Customer Engagement Survey recommended waiting for regulation requirements to keep costs down, 40% recommended proactively implementing industry standard. Through the customer engagement exercise, Union found that the top three most important outcomes for its customers are price, safety and reliability. The intent of the MOP Verification Program is to spread the verification work over several years to keep costs down and mitigate the need for higher expenditures in a shorter timeframe to meet these expected future mandated requirements. MOP verification programs are fundamentally tied to safety and operational reliability. The driver for the regulated requirement in the United States is directly tied to the San Bruno incident. Therefore, while the results of the Customer Engagement Survey were mixed, the Company looked at the outcomes that are most important to customers and decided MOP Verification was a priority.

e) In all likelihood the regulators will provide a deferred time period for demonstrating compliance. By taking a proactive approach it will allow Enbridge Gas to spread the required costs out and allow for more flexibility than that of a regulated period of compliance in alignment with customer preference for steady pace of spend.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Board Staff (STAFF)

Reference: AMP – Exhibit C1/Tab 3/Schedule 1/Pgs. 126

Question:

Union Gas has indicated that it intends to make a major lifecycle replacement as the current version of its billing system (Banner) and underlying technologies will be over 20 years old. The total capital spend on this program is estimated to be $123 million over the ten year planning period.

a) Has Enbridge Gas considered to implement the Enbridge Gas Distribution billing system for the Union Gas rate zones?
b) What would be the costs and savings of discontinuing the Banner system and implementing the Enbridge Gas Distribution billing system for the entire Enbridge Gas franchise area?

Response

a- b) Enbridge Gas is currently reviewing alternatives to consolidate the two Customer Information Systems. This investigation is in the preliminary stages and costs and savings have not been identified.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Board Staff (STAFF)

Reference: AMP – Exhibit C1/Tab 3/Schedule 1/Pgs. 123-127

Question:

Union Gas has a number of Information Technology (IT) applications that provide critical functionality to Union Gas employees and customers by contributing to the support and growth of Union Gas' operations.

a) Has Enbridge Gas completed the review of all Enbridge Gas Distribution and Union Gas IT infrastructure and identified those that can be integrated and the ones that can be discontinued? If yes, please provide details. If no, please provide the estimated timeline of completing the review.
b) Can any of the proposed IT spending projects identified by Enbridge Gas Distribution and Union Gas in the AMP be deferred until the integration of the two utilities? If no, please provide reasons.

Response

a) Enbridge Gas has not completed a detailed review of the EGD and Union rate zones' IT Business Applications. The integration of the systems and processes require careful planning and execution and will take significant effort. The plan is currently under development and is expected to be complete by the end of 2019.

b) As stated in part (a), the detailed review of the IT Business Applications is not complete. As stated in the response to Exhibit I.STAFF.32, part b, the capital expenditure identified in the respective AMPs are considered to be essential expenditures.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Board Staff (STAFF)

Reference: AMP of Enbridge Gas Distribution and Union Gas

Question:

a) Please identify any capital spending that has been deferred or cancelled as a result of implementing Demand Side Management (DSM) initiatives in the ten year capital plans of Enbridge Gas Distribution and Union Gas.
b) Will the integrated AMP identify specific projects that were deferred or cancelled as a result of implementing DSM or other carbon reduction initiatives?
c) Enbridge Gas Distribution has provided a more comprehensive AMP with details about asset condition and the AMP process as compared to the AMP of Union Gas. Please confirm that the integrated AMP will use the approach of Enbridge Gas Distribution.

Response

a) As referenced in Exhibit C1, Tab 2, Schedule 1, page 61, the primary goal of infrastructure planning is to ensure that the utility's infrastructure is sufficiently robust to provide reliable and safe natural gas service that meets the designed condition peak hour requirement forecast. The historical impact of broad-based DSM programs on infrastructure investment is inherently captured in the infrastructure planning process.

   As outlined in EB-2017-0128 DSM Mid-term Review, Appendix E, pages 10 to 12, Enbridge indicated that in 2019 one area of focus would be the review of reinforcement / LTC projects and identification with IRP Study outcomes and Transition Plan processes in mind. At the time of this 2019 rates application this process is ongoing. Further as indicated in the reply submission of EB-2018-0306 Stratford Reinforcement Project:

   > Enbridge Gas is committed to continuing to take steps to study and evolve natural gas IRP. ICF's conclusions from the IRP Report finds that integrating the potential for DSM to reduce infrastructure requirements into the facilities planning process will require significant changes in policy, as well as changes in the utility planning process. Enbridge Gas is reviewing potential reinforcement projects with in-service dates sufficiently in the future to allow geo-targeted DSM and

other non-facility options to be considered as alternatives. Enbridge Gas intends to make an application to the OEB seeking approval of an IRP proposals later this year.[1]

IRP will continue to be monitored as part of Enbridge Gas's Asset Management Plan to ensure advancements made are acknowledged and incorporated during asset investment planning.

b- c) Please see Exhibit I.STAFF.34. At this time, it has not been determined what approach will be followed or what information will be included in the integrated AMP.

[1] EB-2018-0306 Stratford Reinforcement Project, Enbridge Gas Reply Submission, pages 1 to 2.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Board Staff (STAFF)

Reference: AMP of Enbridge Gas Distribution and Union Gas

Question:

Enbridge Gas has provided separate comprehensive AMPs for the Enbridge Gas Distribution rate zone and Union Gas rate zones.

a) What incremental costs did Enbridge Gas incur in developing the USP and the two AMPs submitted in this proceeding? Please segment your response into the following categories:

   I. Direct in-house Labour and Overheads
   II. Consulting and Contractor Costs
   III. Direct Shared Services Costs
   IV. Indirect Costs (Admin & General, indirect Shared Services, Audit)

b) What additional costs will Enbridge Gas incur to fully integrate the Enbridge Gas Distribution and Union Gas AMPs? Please use the same categories.
c) What additional costs will Enbridge Gas incur to maintain and update the USP and the integrated AMP going forward? Please use the same categories.

Response

a) Enbridge Gas is interpreting this question to mean the costs of creating the current versions of the asset management plans and the USP. Both the EGD and Union rate zones have established Asset Management systems to support the creation of an annual asset plan and provide business support. Given that these systems are already in place in 2018, creating the current versions of the Asset Management Plan and USP did not require any incremental costs. The EGD rate zone is able to provide department budgets for 2018.

However, for the Union rate zone, the function of asset management was not consolidated into one department. The costs associated with development are not collected as the work is dispersed across multiple functions in roles that are not solely allocated to the creation of the asset management plan. The costs shown below are an estimate of the internal labour required to support the creation of the asset plan (review, meetings, writing, and prioritization analysis). The costs associated with the analysis that an Asset Class Manager conducts to understand the condition of an asset and to develop a proposed mitigation plan (capital investment) is not included as this work is not incremental to the creation of an asset management plan.

	Summary by Cost Category	EGD 2018 Actual	UG 2018 Actual
I.	Capital - Direct Project Labour	$ 3,170,184	
	OM Labour = Overhead	$ 761,399	$ 563,000
	Total Direct In-House labour and Overhead	$ 3,931,583	**$ 563,000**
	Consulting	$ 92,047	
	Contractor & Other	$ 1,596,382	
II.	Total Consulting & Contractor	$ 1,688,429	
	Burden	$ 6,809	
	Corp.Overhead	$ 62,931	
III. & IV.	Total Direct and Indirect - Shared Services	$ 69,740	
	Total	**$ 5,689,752**	**$ 563,000**

b-c) Enbridge Gas is currently in the process of developing the plan and corresponding costs for the integrated Asset Management Plan. The additional project cost is estimated to be $0.5 million to $1 million per year in 2019 and 2020.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Board Staff (STAFF)

Reference: AMP – Exhibit C1/Tab 3/Schedule 1/Pg. 161

Question:

In its AMP, Union Gas has identified a Compressed Natural Gas (CNG) project along Highway 401. The objective of the project is to provide the reliability and attractive pricing that is critical for the many fleets that regularly use the Highway 401 corridor to make long-term CNG adoption decisions for their operations. In addition, construction and operation of new CNG fueling stations by third parties is also expected to occur and Union Gas will need to provide the gas distribution facilities (e.g. mains, service and meter stations). Union Gas intends to build three stations at an estimated cost of $9 million in 2018.

a) Please list the benefits that distribution customers will receive as a result of Union Gas' CNG initiatives for transportation services.
b) Has Union Gas considered operating the CNG services as a non-utility business?

Response

As described at Exhibit C1, Tab 3, Schedule 1, page 161, the investment in the three Highway 401 CNG refueling stations is a non-utility initiative.

Investment in gas distribution facilities to support the CNG refueling stations will benefit distribution customers to the extent they contribute to earning sharing during the deferred rebasing period. On rebasing the revenues associated with these facilities will be built into rates. Customers will indirectly benefit through reduced transportation costs and reductions in greenhouse gas emissions. Further, these initiatives are consistent with and supported by the provincial governments "A Made-in-Ontario Environment Plan" (pages 33 and 34).

ENBRIDGE GAS INC.
Answer to Interrogatory from
Board Staff (STAFF)

Reference: AMP – Exhibit C1/Tab 3/Schedule 1/Pg. 173 (AMP ID 2375)

Question:

In its AMP, Union Gas has provided information about the Owen Sound Transmission Reinforcement project. The project has been planned as pressure will reach minimums in 2025 on a design day. Union Gas has noted that the project will allow for the addition of five years' in-franchise growth. The estimated cost of the project is $52 million.

a) Please provide the additional capacity that the reinforcement project will add downstream.
b) Please clarify whether the project is classified as a transmission reinforcement as suggested from the title or a distribution reinforcement.
c) Will the reinforcement project require a capital contribution? If yes, what quantum of the costs will be borne by Enbridge Gas ratepayers?

Response

a) The reinforcement project is designed to provide an additional capacity of 17,300 m3/hr of in-franchise growth on the system.

b) The pipeline will be classified as other transmission for the purposes of cost allocation.

c) As this project is not proposed to be constructed until 2025 the detailed need and project economics have not yet been finalized. When the leave to construct application is submitted to the Board for approval details of any capital contribution will be identified.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Board Staff (STAFF)

Reference: AMP – Exhibit C1/Tab 3/Schedule 1/Pg. 174 (AMP ID 863)

Question:

In its AMP, Union Gas has provided information about a second Owen Sound Transmission Reinforcement project. The project has been planned to serve in-franchise growth and to add EPCOR, a new utility that will serve the area of South Bruce. Reinforcement of the Owen Sound Transmission System is required between Durham Gate and Owen Sound Transmission Station. Union Gas has noted that the project will allow for the addition of five years' in-franchise growth and meet the needs of EPCOR. The estimated cost of the project is $58 million.

a) Please explain how this project is related to the earlier Owen Sound Reinforcement Project (AMP ID 2375). Please clearly explain the dependencies between the two projects.
b) Please provide the additional capacity that the reinforcement project will add downstream.
c) Please clarify whether the project is classified as a transmission reinforcement as suggested from the title or a distribution reinforcement.
d) Will the reinforcement project require a capital contribution? If yes, what quantum of the costs will be borne by Enbridge Gas ratepayers?

Response

a) This project (AMP ID 863) was the most beneficial to the system to meet the needs of EPCOR and five years of in-franchise growth on the system. AMP ID 2375 currently planned for 2025 is the most beneficial project after AMP ID 863 is in-service. If AMP ID 863 is not installed, the scope of AMP ID 2375 will change.

b) The reinforcement project was designed to provide an additional capacity of 17,300 m3/hr of in-franchise growth on the system.

c) The pipeline will be classified as other transmission for the purposes of cost allocation.

d) It is expected that a Leave to construct application for this project will be submitted to the Board later in 2019. Final project economics have not been completed at this time. The application will identify the quantum of any capital contributions as well as what costs will be borne by Enbridge Gas ratepayers.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Board Staff (STAFF)

Reference: AMP – Exhibit C1/Tab 3/Schedule 1/Pg. 176

Question:

Based on the current forecast for in-franchise general service and contract growth in the Panhandle Transmission System market, Union Gas has identified the need to reinforce the Panhandle Transmission System for the 2026 to 2027 winter operating season. Union Gas has proposed to extend the NPS 36 pipeline an additional 14 km from the Dover Transmission Station towards the Comber Transmission Station. The total estimated expenditure for the project is $112.6 million from 2024 to 2027.

a) When did Union Gas last reinforce portions of the Panhandle Transmission System? Please provide a brief summary of the completed project.
b) Union Gas has noted that the proposed reinforcement will supply natural gas to four large power generation plants and a number of greenhouses in the Chatham-Kent and Leamington-Kingsville areas. What portion of the additional capacity will be consumed by contract customers and greenhouses?

Response

a) The Panhandle Transmission System was last reinforced in 2017 as part of EB-2016-0186. A brief summary of the project is provided below:

> Union is proposing to reinforce the Panhandle System by constructing approximately 40 kilometres of NPS 36 pipeline from Union's Dawn Compressor Station ("Dawn") in the Township of Dawn Euphemia to the Dover Transmission Station ("Dover Transmission") in the Municipality of Chatham-Kent. The Project also requires station modifications at Dawn, as well as at the Mersea Gate Station, Dover Centre Station and Dover Transmission.
>
> To install the Proposed Pipeline, Union will use a "lift and lay" construction process. Specifically, the existing NPS 16 will be removed (lift) and the new NPS 36 pipeline will be installed in the same easement as that used for the NPS 16 (lay) except where pipeline abandonment sections are required.[1]

[1] EB-2016-0186, Exhibit A, Tab 9, page 1, Lines 4 to13.

The Union rate zone is installing the Kingsville Transmission Reinforcement Project in 2019 as part of EB-2018-0013. A brief project description is provided below.

> Union is proposing to reinforce the Panhandle system by construction approximately 19 kilometres of NPS 20 pipeline from Union's NPS 20 Panhandle Line in the Town of Lakeshore to a new station in the Town of Kingsville in the County of Essex[2]

b) The majority of the created capacity is forecast to be consumed by contract rate customers and greenhouses. Further information is provided at Exhibit C1, Tab 3, Schedule 1, page 176: "in addition to serving residential, commercial and industrial customers, the Panhandle Transmission System also supplies four large power generation plants and a number of greenhouses in the Chatham-Kent and Leamington/Kingsville areas".

[2] EB-2018-0013, Schedule A, Tab 11, page 1, Lines 3 to 5.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Board Staff (STAFF)

Reference: AMP – Exhibit C1/Tab 3/Schedule 1/Pg. 180

Question:

Union Gas has identified further expansion of the Sarnia Industrial Line as one of the proposed projects in the AMP. The system reinforcement is required to serve forecasted industrial contract rate growth in the Sarnia market. The total estimated expenditure for the project is $65 million from 2018 to 2021.

a) How many contract rate customers are expected to receive additional supplies as a result of the proposed expansion?
b) Will any contract rate customers make a capital contribution or contribute through a higher rate or demand charge to receive additional supplies? If not, please explain why.

Response

a) Two.

b) Yes.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Board Staff (STAFF)

Reference: AMP – Exhibit C1/Tab 3/Schedule 1/Pgs. 196-197

Question:

Union Gas has identified replacing the London Line which will extend from Dawn to just south of Komoka Transmission Station, a distance of 75 km. Union Gas has indicated that the condition of the London Lines is generally poor and indicative of a pipeline reaching end of life. Union Gas has further noted that there are currently multiple outstanding leaks located along these lines and sections of the line have been abandoned due to condition.

a) Please explain what abandonment of a section of the line means. Is it not maintained anymore or is not used for providing service?
b) There are currently multiple outstanding leaks. Does Union Gas have an estimate of the natural gas that is lost annually due to leaks in the London Line? If reliable information is not available, please provide a best estimate.

Response

a) Abandoned means that the pipeline segment has been decommissioned and is no longer in service. The London Lines consist of NPS 8 and NPS 10 pipelines which extend in a corridor from Dawn to Komoka, with numerous interconnections between the two pipelines. The pipelines were constructed in the 1930's and 1950's and are nearing the end of their useful life; in certain locations it has been possible to abandon one of the existing pipelines in place following the TSSA's abandonment guidelines. Natural gas service can be provided from the other pipeline in the corridor.

b) Please see Exhibit I.STAFF.45.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Board Staff (STAFF)

Reference: AMP – Exhibit C1/Tab 3/Schedule 1/Pg. 204

Question:

Union Gas has identified the Windsor distribution line for replacement. The replacement will address the integrity and operational risks with the Windsor Line. Based on the integrity concerns and the significant effort and resources spent on repairing leaks on the line, the Windsor Line has been deemed a high risk and has therefore been identified as requiring replacement. The project includes the replacement of the entire 65 km Windsor Line. The existing line is a combination of NPS 10 and NPS 8 and will be replaced by an NPS 6 pipeline at an estimated cost of $88 million. The project will be constructed in 2020.

a) Union Gas has noted that the Windsor Line has used significant resources to repair leaks. What was the total spend on repairing leaks on the Windsor Line in the past five years (2014 to 2018 inclusive)?
b) Why is the proposed line a NPS 6 versus the original NPS 8 pipeline?
c) How much future growth will the NPS 6 pipeline provide as opposed to a NPS 8 pipeline?
d) What is the estimated difference in costs if a NPS 8 pipeline is considered for the project?

Response

a) Since 2014 there have been three major repairs to the Windsor line. The costs of these three repairs were approximately $600,000. In addition, there have been over 25 minor repairs along this line due to condition. The combined costs of these minor repairs were approximately $90,000. Additionally, between 2005 and 2014 there have been four major repairs the combined costs of which were $676,000. There are currently 16 active leaks on the segment identified for replacement that are being actively monitored in compliance with Standard Operating Practice requirements.

b) The proposed NPS 6 3450kPa MOP Windsor Line replacement will operate at a higher pressure than the original NPS 8/NPS 10 1380kPa MOP. By increasing the operating pressure of the pipeline, the diameter can be reduced without impacting the capacity available along the pipeline. Enbridge evaluated the option of installing an NPS 8 3450kPa replacement pipeline, however the identified growth was not sufficient to support the incremental cost associated with the increase in diameter. Based on the expected growth, the proposed NPS 6 replacement will be able to serve the existing and forecasted demand for the next 20 years.

c) See response to part b).

d) The incremental magnitude cost to replace the current line with a NPS 8 pipeline instead of the currently planned NPS 6 pipeline would be approximately $16 million. The cost increase is due to higher material costs and increased construction labour and equipment costs required to complete installation including larger equipment, deeper/wider trenching, and more welding.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Board Staff (STAFF)

Reference: Customer Engagement Research

Question:

With respect to customer concerns among large volume customers, 24% mentioned costs associated with new natural gas service as a concern.

a) Please confirm whether Enbridge Gas probed this concern any further and provide further information on this issue if available.
b) Is this concern related to the PI calculation completed for every new infill customer and requiring a CIAC to complete the connection to the distribution system?

Response

a) The intent of the customer engagement survey was to get customer preferences regarding various future initiatives which would then inform the Company's investment plan. While the Company didn't specifically take steps to probe the results from that particular survey, it regularly completes other market research projects to engage with customers and understand their concerns, needs and preferences.

   Please see Exhibit I.STAFF.33 for an overview of how Enbridge Gas incorporated feedback from the customer engagement process into its business plans.

b) No, customers did not express any specific concerns related to the PI calculation and CIAC for infill customer to connect to the distribution system.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Board Staff (STAFF)

Reference: Exhibit D1/Tab 1/Schedule 1/Pg.22

Question:

Slightly more than half (56%) of large volume customers believe that increasing rates by 1.5% over the next five years to keep up with aging infrastructure costs to maintain the current level of reliability and safety is reasonable (14%) or necessary (42%), compared to four in ten (40%) who would oppose it.

Did Enbridge Gas probe the results further to understand why 40% of the respondents would oppose an increase in rates to cover costs associated with aging infrastructure?

Response

Please see Exhibit I.STAFF.77, part a).

ENBRIDGE GAS INC.
Answer to Interrogatory from
Board Staff (STAFF)

Reference: Exhibit D1/Tab 2/Schedule 1/Pg. 56

Question:

The Union Gas survey found that three in four (74%) of residential participants find the price for distributing gas “reasonable” with 21% who find it “very reasonable”. Nearly one in five (17%) find it “somewhat unreasonable” and just 6% find it “very unreasonable”.

Is there any significant difference in the results among those who are on Equal Billing Plan and those who are not?

Response

The referenced Customer Engagement survey did not distinguish between customers on the equal billing plan and those who are not on equal billing.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Board Staff (STAFF)

Reference: Exhibit D1/Tab 2/Schedule 1/Pgs. 75-95

Question:

In its survey, Union Gas sought feedback on a number of trade-offs and also tried to gauge customer perception for additional spending that was quantified as a rate impact for customers. For example, the impact of maintenance capital spending is $1 per year for residential customers, renovating older buildings was 50 cents a year per residential customer, information technology spending was $3 a year per residential customer, replacement of bare and unprotected pipes would cost $1 a year per residential customer, website enhancements for $1 a year per residential customer, research spending on new technologies costing $3 per year per residential customer and other such spending initiatives.

a) Were the respondents provided information on the possible cumulative rate impact of all these initiatives? If no, why not?
b) Did Union Gas gauge the perception of customers on the cumulative spending and how supportive they were if all the proposed initiatives were implemented?

Response

a) Yes. Please see Exhibit D1, Tab 2, Schedule 1, page 248, which is also provided below for convenience.

> Currently, the average residential customer pays $390 a year in distribution rates. On average this is $32.50 each month but in practice it is higher in the winter and lower in the summer due to the variable delivery charge when people use more gas for heating. For each question, the financial impact is expressed as the dollar impact each year on an average residential bill. The actual impact will depend on your own individual usage. While the individual impact of each decision may be small, please keep in mind the total impact of all the choices included in this planning process could add up to a significant increase.
>
> You will see that each time you are asked for your opinion, there is room for comments. Feel free to use these comment sections to explain why you prefer a particular option, or in any other way to expand on your viewpoint. Your comments will help develop a list of criteria Union Gas can use when addressing other issues.

b) Customers were not asked about the cumulative rate impacts of their choices in this engagement. INNOVATIVE did not develop a tool to enable customers to review their decisions and the cumulative bill impacts of those decisions until 2018. The engagement relied on both ratings and rankings of customer outcomes to provide customer insights for the utility to consider in assessing the best balance between system improvements and rate increases.

Please see Exhibit I.STAFF.33 for an overview of how Enbridge Gas incorporated feedback from the customer engagement process in its business plans.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Association of Power Producers of Ontario (APPrO)

Reference: Exhibit B1, Tab 1, Schedule 1 Section 2.2.6 Capital Pass Through Deferral Accounts – Union Rate Zones

Preamble: Enbridge proposes to make adjustments to rate base and depreciation based on the Board's direction in the EB-2017-0306/0307 to reflect certain capital pass-through during prior IRM. Enbridge has indicated that it proposes to continue to capture the utility tax timing variances in the respective deferral accounts to recognize the reversal of the benefits customers received in rates from 2014-2018. Over the following PCI period, Enbridge notes that it would receive $124.1 million of utility tax timing differences based on the current forecast and without capturing the reversal in the deferral account, customers would receive a benefit of $182.0 million.

Question:

Please identify if Enbridge raised the issue of tax timing differences in the above noted proceedings and if so, the Board's ruling on the matter.

Response

No. At the time of the MAADs proceeding, Enbridge Gas intended to continue with Union's capital pass-through deferral accounts to capture the impact of changes in income tax timing differences.

In the MAADs Decision, the Board approved Enbridge Gas's proposal for the deferral and variance accounts that would continue upon amalgamation[1] including Union's capital pass-through deferral accounts. Enbridge Gas's proposal to fix the capital pass-through revenue requirement in rates and discontinue the deferral account treatment for the projects with the exception of the utility tax timing differences was made following the MAADs Decision. For further details of why Enbridge Gas is proposing to adjust the capital pass-through deferral accounts please see Exhibit I.STAFF.8 a).

[1] EB-2017-0306/EB-2017-0306 Decision with Reasons, p. 45.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Association of Power Producers of Ontario (APPrO)

Reference: i) Exhibit B Tab 2 Schedule 1

Preamble: Enbridge is seeking approval for revenue requirement associated with the replacement of the Sudbury lateral that was constructed in 2018. APPRO would like to better understand this investment. The Sudbury lateral LTC application was filed on May 5, 2017 and was approved by the Board on September 28, 2017 and was planned to be in service in 2018.

Question:

a) Please confirm that the project is operational and went into service in 2018. If it failed to go into service in 2018, please explain why Enbridge failed to meet its planned in service date.
b) Enbridge notes that $3.4 million is to go into service in 2019. Please explain what this amount is in relation to (i.e. is it related to remediation work or is a portion of the pipeline that will not go into service until 2019 or some other reason).
c) Given that this project was approved for construction in 2017, did Enbridge seek approval for a capital pass through in its 2018 rate case? If no, why not? If yes, what was the determination?
d) Please confirm that the 2014-2018 IRM expired on December 31, 2018.
e) If the project went into service in 2018, please outline the income tax effects, if any, that were captured in 2018.
f) If the Board does not approve the request to provide the full year revenue requirement of approximately $9 million in 2019, how many basis points would this reduce Enbridge's ROE in 2019?

Response

a) The Sudbury Replacement Project went into service in October of 2018.

b) The $3.4 million in spend includes construction clean up, baseline integrity inspection, painting of impacted pipeline stations and anode installation on some services lines off the replaced pipeline.

c) The Sudbury Replacement Project did not qualify for capital pass through treatment in 2018 because there were only two months of revenue requirement, but within 2019 there is a full year's revenue requirement that would make it eligible.

d) Confirmed.

e) The income tax captured in 2018 provided a benefit to the project nearly offsetting the operating cost and return components of the 2018 revenue requirement. The 2018 income tax effect can be found in the ICM revenue requirement calculation which is filed as Exhibit B1, Tab 2, Schedule 1, Appendix E.

f) At present, without knowing what Enbridge Gas's 2019 actual utility rate base will be, Enbridge Gas is only able to provide an approximate ROE impact. Assuming Enbridge Gas's revenue stream was $9.8 million lower than it otherwise would have been due to the Sudbury ICM amount not being approved it would result in an after tax reduction in utility earnings of approximately $7.2 million (assumed tax rate of 26.5%). Further, assuming that Enbridge Gas's 2019 utility rate base will be in the range of $13 billion to $14 billion, which would result in a 36% deemed equity level of $4.68 billion to $5.04 billion, a $7.2 million reduction in utility income would translate into a utility ROE reduction in the range of 14 to 15 basis points.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Association of Power Producers of Ontario (APPrO)

Reference: i) Exhibit B1 Tab 2 Schedule 1

Preamble: The ICM materiality threshold within the Union Rate Zone for 2019 is $375.2 million. Enbridge is seeking ICM funding for amounts in excess of this threshold for several specific projects. Enbridge is seeking funding in 2019 to cover the $91.9 million in capital associated with the Sudbury Lateral, as well as $146.1 million associated with the Kingsville and Stratford reinforcements. $2.8 million of these capital amounts may be below the threshold amounts and therefore not eligible for incremental ICM funding. Enbridge has applied this $2.8 million to reduce the costs of the Kingsville and Stratford laterals.

Question:

a) Please explain why Enbridge is proposing to apply all of the capital amounts falling below the threshold amounts (i.e. $2.8 million in this case) to the Union South projects only? Given that there are ICM projects in other rate zones, why wouldn't a proportionate allocation among both rate zones be more appropriate? Since projects occur in each rate zone, what is the rate impact in each rate zone under this alternate allocation methodology?
b) In the event some of the other regularly occurring capital amounts are elevated over the historical average (e.g. General Plant) in the same year a major reinforcement project is also proposed, this could have the effect of increasing the ICM amount attributable to reinforcement than had these other capital expenditures not occurred. If the allocation methodology for the major reinforcements is different from the allocation methodology for the other asset types also experiencing higher spending, then the resulting rates could be distorted. APPrO would like to understand the cost allocation principles that Enbridge intends to apply during the IRM period should these situations occur.
c) To the extent that the threshold capital amounts are not exceeded in any year, is it the company's intention to "bank" the differences to apply against future amounts that do exceed the threshold?

Response

a) The $2.8 million reduction in project capital is a result of the Union rate zones capital spend exceeding the maximum eligible incremental capital for the Union rate zones identified at Exhibit B1, Tab 2, Schedule 1, Table 7. Since the reduction is attributable to the Union rate zones calculation, it has been applied to the Union rate zones.

   There is no 2019 in-service capital forecast for the Union North rate zone, therefore the reduction for the Union rate zones has been applied to the Union South rate zone only.

b) As per the OEB's ICM policy, Enbridge Gas is required to propose cost allocation and associated recovery of the incremental revenue requirement from customer classes for each discrete project that exceed the ICM materiality threshold. Note that projects proposed for incremental capital funding during the IRM period must be discrete projects rather than programs or regularly occurring capital amounts. Enbridge Gas's proposed cost allocation and incremental revenue recovery from customers in this application (as will also be the case in future applications) are based on cost causality (i.e., customers' usage of the ICM project assets) for each discrete ICM project. The proposed cost allocation methodology for 2019 ICM projects is provided at Exhibit B1, Tab 2, Schedule 1, pages 32 to 34.

   Also note that in-service capital expenditures / additions below the ICM materiality threshold are recovered through Enbridge's base rates during the IRM period. Accordingly, cost allocation is not carried out or proposed for those assets.

c) No.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Association of Power Producers of Ontario (APPrO)

Reference: i) Exhibit B1 Tab 2 Schedule 1, Table 10

Preamble: Enbridge has provided projections on the 2019 Incremental Revenue Requirement for the ICM projects.

Question:

Enbridge notes that there were no material incremental O&M expenses associated with the 2019 eligible projects and therefore excluded in the incremental revenue requirement calculation.

a) Please confirm that the Sudbury lateral in fact lowers the O&M costs, due to the high historical integrity issues. If so, please explain why there would not be a reduction in O&M costs due to this ongoing savings.
b) Similarly, the Don River crossing replacement would also be expected to lower O&M costs as a result of removing exposed pipeline and a bridge that would otherwise require increased maintenance and inspection. Please explain why there would not be a credit to O&M expenses as a result of this replacement.
c) Please provide the annual O&M expenses incurred for each section of pipe that is being replaced for each of the above noted projects for the last 5 years.
d) Please indicate if potential O&M savings form a part of the business case to replace these facilities, if so please provide a copy of the respective business case.

Response

a) The Sudbury lateral replacement project is replacing an existing pipeline. The regular maintenance on the pipeline (such as leak survey, corrosion survey, valve inspections, etc.) will still be required, so it will not lead to O&M savings. Although the inline inspection interval will be decreased from every 7 years to 10 years, these savings are not significant. The majority of the repair costs, that will be avoided in the future, are attributed to replacement of discrete sections of pipe due to integrity concerns. These discrete replacements have therefore been addressed with maintenance capital rather than O&M expense.

b) The Don River crossing replacement project (starting in April) is replacing above ground pipe bridge crossing (approx. 45 metres) with below ground crossing of the river. The regular maintenance on the pipe (such as leak survey, corrosion survey, valve inspections, etc.) will still be required and will not lead to O&M savings. As this is a short section of pipeline, the regular pigging activities that are a continued requirement will not result in O&M savings.

c) O&M costs are not allocated to sections of pipe, thus, unable to provide a response to this question.

d) There is no business case incorporating O&M savings related to the Sudbury lateral and Don River crossing replacement project mentioned in a) and b) above.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Building Owners and Managers Association of Greater Toronto (BOMA)

Reference: Application Letter

Question:

Please provide the annual rate increase for 2019 over 2018, with and without any proposed rate riders, for each rate class in the three rate zones. Assume a low, medium, and high consumption case for each rate class.

Response

The proposed bill impacts for the EGD rate zone can be found at Exhibit F1, Tab 1, Working Papers, Schedule 3. There are no proposed ICM rate riders for the EGD rate zone.

The proposed bill impacts for the Union South rate zone can be found at Exhibit F1, Tab 2, Working Papers, Schedule 4, pages. 2 to 3. There are no proposed ICM rate riders for the Union South rate zone.

The proposed bill impacts for the Union North rate zone can be found at Exhibit F1, Tab 2, Working Papers, Schedule 4, page 1 and include the ICM rate rider. Attachment 1 compares the proposed bill impacts for the Union North rate zone excluding and including the ICM rate rider.

ENBRIDGE GAS INC.
UNION RATE ZONES
Union North In-Franchise
Calculation of 2019 Sales Service and Direct Purchase Bill Impacts for Typical Small and Large Customers

Line No.	Particulars	Approved EB-2018-0253 (1) Total Bill (2) ($)	Proposed - EB-2018-0305 Excluding ICM Rate Rider Total Bill (3) ($)	Total Bill Change ($)	Total Bill Impact (%)	Proposed - EB-2018-0305 Including ICM Rate Rider Total Bill (4) ($)	Total Bill Change ($)	Total Bill Impact (%)
		(a)	(b)	(c) = (b - a)	(d) = (c / a)	(e)	(f) = (e - a)	(g) = (f / a)
	Small Rate 01							
1	Delivery Charges	455	454	(0.89)	-0.2%	463	7.91	1.7%
2	Gas Supply Charges (5)	497	494	(3.03)	-0.6%	494	(3.03)	-0.6%
3	Total Bill	952	948	(3.92)	-0.4%	957	4.88	0.5%
4	Sales Service Impact			(3.92)	-0.4%		4.88	0.5%
5	Bundled-T (Direct Purchase) Impact			(3.98)	-0.6%		4.82	0.7%
	Small Rate 10							
6	Delivery Charges	4,868	4,842	(26)	-0.5%	5,065	198	4.1%
7	Gas Supply Charges (5)	12,326	12,259	(68)	-0.5%	12,259	(68)	-0.5%
8	Total Bill	17,194	17,101	(93)	-0.5%	17,324	130	0.8%
9	Sales Service Impact			(93)	-0.5%		130	0.8%
10	Bundled-T (Direct Purchase) Impact			(95)	-1.0%		128	1.4%
	Large Rate 10							
11	Delivery Charges	16,059	15,952	(107)	-0.7%	16,883	824	5.1%
12	Gas Supply Charges (5)	51,360	51,078	(282)	-0.5%	51,078	(282)	-0.5%
13	Total Bill	67,419	67,030	(389)	-0.6%	67,961	542	0.8%
14	Sales Service Impact			(389)	-0.6%		542	0.8%
15	Bundled-T (Direct Purchase) Impact			(397)	-1.2%		534	1.6%
	Small Rate 20							
16	Delivery Charges	74,615	74,519	(96)	-0.1%	79,733	5,118	6.9%
17	Gas Supply Charges (5)	519,322	516,541	(2,781)	-0.5%	516,541	(2,781)	-0.5%
18	Total Bill	593,936	591,059	(2,877)	-0.5%	596,273	2,337	0.4%
19	Sales Service Impact			(2,877)	-0.5%		2,337	0.4%
20	Bundled-T (Direct Purchase) Impact			(2,967)	-1.5%		2,247	1.1%
	Large Rate 20							
21	Delivery Charges	290,019	287,415	(2,605)	-0.9%	309,761	19,742	6.8%
22	Gas Supply Charges (5)	2,506,994	2,495,139	(11,855)	-0.5%	2,495,139	(11,855)	-0.5%
23	Total Bill	2,797,013	2,782,554	(14,459)	-0.5%	2,804,900	7,887	0.3%
24	Sales Service Impact			(14,459)	-0.5%		7,887	0.3%
25	Bundled-T (Direct Purchase) Impact			(14,909)	-1.8%		7,437	0.9%
	Average Rate 25							
26	Delivery Charges	61,501	63,522	2,021	3.3%	70,984	9,483	15.4%
27	Gas Supply Charges (5)	331,301	331,495	193	0.1%	331,495	193	0.1%
28	Total Bill	392,802	395,016	2,214	0.6%	402,478	9,676	2.5%
29	Sales Service Impact			2,214	0.6%		9,676	2.5%
30	T-Service (Direct Purchase) Impact			2,021	3.3%		9,483	15.4%
	Small Rate 100							
31	Delivery Charges	256,549	264,426	7,877	3.1%	314,925	58,376	22.8%
32	Gas Supply Charges (5)	6,375,442	6,374,349	(1,093)	0.0%	6,374,349	(1,093)	0.0%
33	Total Bill	6,631,992	6,638,776	6,784	0.1%	6,689,274	57,282	0.9%
34	Sales Service Impact			6,784	0.1%		57,282	0.9%
35	T-Service (Direct Purchase) Impact			7,877	3.1%		58,376	22.8%
	Large Rate 100							
36	Delivery Charges	2,083,042	2,144,490	61,448	2.9%	2,573,727	490,685	23.6%
37	Gas Supply Charges (5)	55,569,773	55,560,797	(8,976)	0.0%	55,560,797	(8,976)	0.0%
38	Total Bill	57,652,815	57,705,287	52,472	0.1%	58,134,523	481,708	0.8%
39	Sales Service Impact			52,472	0.1%		481,708	0.8%
40	T-Service (Direct Purchase) Impact			61,448	2.9%		490,685	23.6%

Notes:
(1) Reflects approved rates per October 2018 QRAM (EB-2018-0253), Appendix A.
(2) EB-2018-0305, Exhibit F1, Tab 2, Rate Order, Working Papers, Schedule 4, p. 1, column (a).
(3) EB-2018-0305, Exhibit B1, Tab 2, Schedule 1, Appendix H, column (a).
(4) EB-2018-0305, Exhibit F1, Tab 2, Rate Order, Working Papers, Schedule 4, p. 1, column (c).
(5) Gas Supply charges based on Union North East Zone.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Building Owners and Managers Association of Greater Toronto (BOMA)

Reference: Application Letter

Question:

Please provide data when EGD/Union commenced work on their 2019 rates applications. Given that the companies have been under common ownership since February 27, 2017, how much of the application for the 2019 rates were they able to do prior to the certificate of amalgamation being issued?

Response

EGD and Union have been aware of the need to bring forward a 2019 rates application for some time. However, the application could not be completed until the framework in the MAADs and Rate Setting Mechanism proceeding was approved.[1]

As the 2019 rates application was filed in December 2018, it was all completed prior to the January 1, 2019 effective date of the amalgamation and receipt of the Certificate of Status on January 10, 2019.

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

ENBRIDGE GAS INC.
Answer to Interrogatory from
Building Owners and Managers Association of Greater Toronto (BOMA)

Reference: Exhibit B1, Tab 1, Schedule 1, p14

Question:

(a) Why should the Board establish a deferral account for capital projects which are funded from ICM funds when they do not do so for capital projects funded through existing rates (price cap index plus growth adjustments)?

(b) Open Bill Revenue Variance Account – On what basis should the ratepayers be responsible for all of the shortfall between revenue from the program and $4,889M? Please provide the numerical analysis underpinning that feature of the account.

Response

a) Enbridge Gas is requesting the establishment of the deferral accounts in relation to capital projects funded through ICM in accordance with the Board policy on ICM.

b) Enbridge credits ratepayers with $5.389 million for OBA program net revenues each year. Parties to the settlement agreements which govern the provision of Open Bill services agreed that it would be appropriate for Enbridge to be credited any shortfall between actual annual net revenues and $4.889 million. The Board approved settlement agreement related to the provision of OBA services (EB-2009-0043) for the years 2009 to 2012 established the Open Bill Revenue Variance Account (OBRVA) and the mechanics of that variance account, including the provision that Enbridge would be credited for annual net revenues that are less than $4.889 million. Subsequent Board approved settlement proposals - EB-2011-0354 which related to OBA services for 2013 and EB-2013-0099 which related to OBA services for 2014 to 2018 – carried forward the OBRVA as established in EB-2009-0043. In the EB-2017-0306/0307 MAADs decision, the OEB approved the continuation of the OBRVA for the deferred rebasing term. In the recent EB-2018-0319 Board-approved Settlement Proposal, all parties agreed that Enbridge will continue offering the OBA program under its existing financial terms (including the operation of the OBRVA) until such time as a decision is rendered in that proceeding.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Building Owners and Managers Association of Greater Toronto (BOMA)

Reference: Exhibit B1, Tab 1, Schedule 1, Appendix A, p18

Question:

Please explain the revised wording of the PTUVA Account.

Response

The wording of the EGD rate zone PTUVA accounting order has been updated to reflect the findings of the Board's EB-2017-0306 / EB-2017-0307 Decision and Order, in the Company's application for amalgamation and rate setting mechanism proceeding. [1]

For reference, a blacklined version of the EGD Rate Zone PTUVA accounting order showing the changes that were made to the account wording is provided at Exhibit I.STAFF.17 Attachment 1.

[1] EB-2017-0306/ EB-2017-0307 Decision and Order, August 30, 2018, page 45.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Building Owners and Managers Association of Greater Toronto (BOMA)

Reference: Report on 2019 Rates on "Unaccounted for Gas"; p63

Question:

(a) Please provide a copy of the Certificate of Amalgamation, together with any submissions to the OSC or the Ministry of Commercial and Corporation Affairs Ontario to support the Application for Amalgamation.

(b) Please confirm that the Union and EGD rates are not being harmonized pursuant to this Application and, in effect, each of the existing 2018 rates of EGD and Union will be escalated by the formula authorized by the Board in the MAADs application.

Response

a) Attached are the Articles of Amalgamation that were filed with the Ontario Ministry of Government and Consumer Services that effect the amalgamation as of January 1, 2019. The first page of the Articles with the Ministry's stamp may be referred to as the Certificate of Amalgamation. No other submissions to the Ontario Securities Commission or the Ministry were required to effect the amalgamation.

b) Confirmed.

Request ID: 022567947
Demande n° :
Transaction ID: 70450109
Transaction n° :
Category ID: CT
Catégorie :

Province of Ontario
Province de l'Ontario
Ministry of Government Services
Ministère des Services gouvernementaux

Date Report Produced: 2019/01/10
Document produit le :
Time Report Produced: 09:02:55
Imprimé à :

CERTIFICATE OF STATUS
ATTESTATION DU STATUT JURIDIQUE

This is to certify that according to the records of the Ministry of Government Services

D'après les dossiers du Ministère des Services gouvernementaux, nous attestons que la société

ENBRIDGE GAS INC.

Ontario Corporation Number

Numéro matricule de la société (Ontario)

005008296

is a corporation incorporated, amalgamated or continued under the laws of the Province of Ontario.

est une société constituée, prorogée ou née d'une fusion aux termes des lois de la Province de l'Ontario.

The corporation came into existence on

La société a été fondée le

JANUARY 01 JANVIER, 2019

and has not been dissolved.

et n'est pas dissoute.

Dated

Fait le

JANUARY 10 JANVIER, 2019

Barbara Duckitt

Director
Directeur

The issuance of this certificate in electronic form is authorized by the Ministry of Government Services.
La délivrance du présent certificat sous forme électronique est autorisée par le Ministère des Services gouvernementaux.

For Ministry Use Only
À l'usage exclusif du ministère

Ministry of Government and Consumer Services
Ministère des Services gouvernementaux et des Services aux consommateurs

Ontario

CERTIFICATE
This is to certify that these articles are effective on

CERTIFICAT
Ceci certifie que les présents statuts entrent en vigueur le

JANUARY 01 JANVIER, 2019

Director / Directrice
Business Corporations Act / Loi sur les sociétés par actions

17

Ontario Corporation Number
Numéro de la société en Ontario

5008296

Form 4
Business Corporations Act

Formule 4
Loi sur les sociétés par actions

ARTICLES OF AMALGAMATION
STATUTS DE FUSION

1. The name of the amalgamated corporation is: (Set out in BLOCK CAPITAL LETTERS)
Dénomination sociale de la société issue de la fusion: (Écrire en LETTRES MAJUSCULES SEULEMENT) :

ENBRIDGE GAS INC.

2. The address of the registered office is:
Adresse du siège social :

500 Consumers Road

Street & Number or R.R. Number & if Multi-Office Building give Room No. /
Rue et numéro ou numéro de la R.R. et, s'il s'agit d'un édifice à bureaux, numéro du bureau

Toronto ONTARIO M2J 1P8

Name of Municipality or Post Office /
Nom de la municipalité ou du bureau de poste

Postal Code/Code postal

3. Number of directors is: / Nombre d'administrateurs :
Fixed number / Nombre fixe:
OR minimum and maximum / OU minimum et maximum: 3 10

4. The director(s) is/are: / Administrateur(s) :

First name, middle names and surname Prénom, autres prénoms et nom de famille	Address for service, giving Street & No. or R.R. No., Municipality, Province, Country and Postal Code Domicile élu, y compris la rue et le numéro ou le numéro de la R.R., le nom de la municipalité, la province, le pays et le code postal	Resident Canadian State 'Yes' or 'No' Résident canadien Oui/Non
Cynthia L. Hansen	500 Consumers Road Toronto, Ontario, Canada M2J 1P8	Yes
James E. Sanders	500 Consumers Road Toronto, Ontario, Canada M2J 1P8	Yes
David G. Unruh	500 Consumers Road Toronto, Ontario, Canada M2J 1P8	Yes

5. Method of amalgamation, check A or B
Méthode choisie pour la fusion – Cocher A ou B :

A - **Amalgamation Agreement / Convention de fusion :**

☒ The amalgamation agreement has been duly adopted by the shareholders of each of the amalgamating corporations as required by subsection 176 (4) of the *Business Corporations Act* on the date set out below.

Les actionnaires de chaque société qui fusionnne ont dûment adopté la convention de fusion conformément au paragraphe 176(4) de la *Loi sur les sociétés par actions* à la date mentionnée ci-dessous.

or
ou

B - **Amalgamation of a holding corporation and one or more of its subsidiaries or amalgamation of subsidiaries / Fusion d'une société mère avec une ou plusieurs de ses filiales ou fusion de filiales :**

☐ The amalgamation has been approved by the directors of each amalgamating corporation by a resolution as required by section 177 of the *Business Corporations Act* on the date set out below.

Les administrateurs de chaque société qui fusionne ont approuvé la fusion par voie de résolution conformément à l'article 177 de la *Loi sur les sociétés par actions* à la date mentionnée ci-dessous.

The articles of amalgamation in substance contain the provisions of the articles of incorporation of
Les statuts de fusion reprennent essentiellement les dispositions des statuts constitutifs de

and are more particularly set out in these articles.
et sont énoncés textuellement aux présents statuts.

Names of amalgamating corporations Dénomination sociale des sociétés qui fusionnent	Ontario Corporation Number Numéro de la société en Ontario	Date of Adoption/Approval Date d'adoption ou d'approbation Year / année – Month / mois – Day / jour
ENBRIDGE GAS DISTRIBUTION INC.	5594	2018/12/20
UNION GAS LIMITED	1273229	2018/12/20

6. Restrictions, if any, on business the corporation may carry on or on powers the corporation may exercise.
Limites, s'il y a lieu, imposées aux activités commerciales ou aux pouvoirs de la société.

None.

7. The classes and any maximum number of shares that the corporation is authorized to issue:
Catégories et nombre maximal, s'il y a lieu, d'actions que la société est autorisée à émettre :

The Corporation is authorized to issue an unlimited number of Class A common shares, an unlimited number of Class B common shares and an unlimited number of preference shares, issuable in series.

8. Rights, privileges, restrictions and conditions (if any) attaching to each class of shares and directors authority with respect to any class of shares which may be issued in series:

Droits, privilèges, restrictions et conditions, s'il y a lieu, rattachés à chaque catégorie d'actions et pouvoirs des administrateurs relatifs à chaque catégorie d'actions qui peut être émise en série :

See pages 4A to 4E following.

A. Class A Common Shares

The Class A common shares, as a class, shall be designated as the Class A common shares and shall have attached thereto the following rights, privileges, restrictions and conditions:

1. Dividends

After payment to the holders of the Preference Shares of the amount or amounts to which they may be entitled, the holders of the Class A common shares shall be entitled to receive, and the Corporation shall pay thereon, any dividends declared by the Corporation on the Class A common shares, if, as and when declared by the directors of the Corporation out of moneys of the Corporation properly applicable to the payment of dividends, in such amounts as may be determined by the directors from time to time, each such dividend to be paid to such holders on such date as may be fixed by the directors at the time of declaration of such dividend. Unless the holders of the Class A common shares and the holders of the Class B common shares consent in writing otherwise, the Class A common shares and the Class B common shares shall rank equally as to dividends on a share for share basis, and all dividends declared by the Corporation shall be declared in equal amounts per share on all Class A common shares and all Class B common shares at the time outstanding, without preference or distinction.

2. Subdivision or Consolidation

No subdivision or consolidation of the Class B common shares or the Class A common shares shall occur unless, simultaneously, the Class A common shares or the Class B common shares, as the case may be, are subdivided or consolidated in the same manner, so as to maintain and preserve the relative rights of the holders of the shares of each of such classes.

3. Liquidation, Dissolution or Winding-up

Upon the liquidation, dissolution or winding-up of the Corporation, whether voluntary or involuntary, or other distribution of the property and assets of the Corporation among its shareholders for the purpose of winding-up its affairs, and after payment to the holders of the Preference Shares of the amount or amounts to which they may be entitled, the holders of the Class A common shares and the holders of the Class B common shares shall be entitled to receive the remaining property and assets of the Corporation and shall be entitled to share equally, on a share for share basis, in all distributions of such property and assets without preference or distinction unless the holders of the Class A common shares and the holders of the Class B common shares consent in writing otherwise.

4. Class A Common Shares to be Voting

The holders of the Class A common shares shall be entitled to receive notice of and to attend all meetings of shareholders of the Corporation, other than separate meetings of the holders of another class or series of shares, and to vote at any such meeting on the basis of one (1) vote for each Class A common share held.

B. Class B Common Shares

The Class B common shares, as a class, shall be designated as the Class B common shares and shall have attached thereto the following rights, privileges, restrictions and conditions:

1. Dividends

After payment to the holders of the Preference Shares of the amount or amounts to which they may be entitled, the holders of the Class B common shares shall be entitled to receive, and the Corporation shall pay thereon, any dividends declared by the Corporation on the Class B common shares, if, as and when declared by the directors of the Corporation out of moneys of the Corporation properly applicable to the payment of dividends, in such amounts as may be determined by the directors from time to time, each such dividend to be paid to such holders on such date as may be fixed by the directors at the time of declaration of such dividend. Unless the holders of the Class A common shares and the holders of the Class B common shares consent in writing otherwise, the Class A common shares and the Class B common shares shall rank equally as to dividends on a share for share basis, and all dividends declared by the Corporation shall be declared in equal amounts per share on all Class A shares and all Class B common shares at the time outstanding, without preference or distinction.

2. Subdivision or Consolidation

No subdivision or consolidation of the Class B common shares or the Class A common shares shall occur unless, simultaneously, the Class A common shares or the Class B common shares, as the case may be, are subdivided or consolidated in the same manner, so as to maintain and preserve the relative rights of the holders of the shares of each of such classes.

3. Liquidation, Dissolution or Winding-up

Upon the liquidation, dissolution or winding-up of the Corporation, whether voluntary or involuntary, or other distribution of the property and assets of the Corporation among its shareholders for the purpose of winding-up its affairs, and after payment to the holders of the Preference Shares of the amount or amounts to which they may be entitled, the holders of the Class A common shares and the holders of the Class B common shares shall be entitled to receive the remaining property and assets of the Corporation and shall be entitled to share equally, on a share for share basis, in all distributions of such property and assets without preference or distinction unless the holders of the Class A common shares and the holders of the Class B common shares consent in writing otherwise.

4. Class B Common Shares to be Voting

The holders of the Class B common shares shall be entitled to receive notice of and to attend all meetings of shareholders of the Corporation, other than separate meetings of the holders of another class or series of shares, and to vote at any such meeting on the basis of one (1) vote for each Class B common share held.

C. Preference Shares

The Preference Shares, as a class, shall be designated as the Preference Shares and shall have attached thereto the following rights, privileges, restrictions and conditions:

1. Directors' Right to Issue in One or More Series

The Preference Shares may be issued at any time or from time to time in one or more series. Before any Preference Shares of a series are issued, the board of directors of the Corporation shall fix the number of Preference Shares that will form such series and shall, subject to the limitations set out in the articles of the Corporation, determine the designation, rights, privileges, restrictions and conditions to be attached to the Preference Shares of such series, the whole subject to the filing with the Director (as defined in the Business Corporations Act (Ontario) (the "**Act**")) of Articles of Amendment containing a description of such series including the rights, privileges, restrictions and conditions determined by the board of directors of the Corporation.

2. Ranking of the Preference Shares

The Preference Shares of each series shall rank on a parity with the Preference Shares of every other series with respect to dividends and return of capital in the event of the liquidation, dissolution or winding up of the Corporation, and shall be entitled to a preference over the Class A common shares and the Class B common shares of the Corporation and over any other shares ranking junior to the Preference Shares with respect to priority in payment of dividends and in the distribution of assets in the event of the liquidation, dissolution or winding-up of the Corporation, whether voluntary or involuntary, or other distribution of the property and assets of the Corporation among its shareholders for the purpose of winding-up its affairs. If any cumulative dividends, whether or not declared, or declared non-cumulative dividends or amounts payable on a return of capital in the event of the liquidation, dissolution or winding up of the Corporation are not paid in full in respect of any series of the Preference Shares, the Preference Shares of all series shall participate rateably in respect of such dividends in accordance with the sums that would be payable on such shares if all such dividends were declared and paid in full, and in respect of such return of capital in accordance with the sums that would be payable on such return of capital if all sums so payable were paid in full; provided, however, that if there are insufficient assets to satisfy in full all such claims as aforesaid, the claims of the holders of the Preference Shares with respect to return of capital shall be paid and satisfied first and any assets remaining thereafter shall be applied towards the payment and satisfaction of claims in respect of dividends. The Preference Shares of any series may also be given such other preferences not inconsistent with the rights, privileges, restrictions and conditions attached to the Preference Shares as a class over the Class A common shares and the Class B common shares of the Corporation and over any other shares ranking junior to the Preference Shares as may be determined in the case of such series of Preference Shares.

3. Preference Shares to be Non-Voting

Except as hereinafter referred to or as required by law or unless provision is made in the Articles relating to any series of Preference Shares that such series is entitled to vote, the holders of the Preference Shares as a class shall not be entitled as such to receive notice of, to attend or to vote at any meeting of the shareholders of the Corporation.

4. Amendment with Approval of Holders of Preference Shares

The rights, privileges, restrictions and conditions attached to the Preference Shares as a class may be added to, changed or removed but only with the approval of the holders of the Preference Shares given as hereinafter specified.

5. Approval of Holders of the Preference Shares

The approval of the holders of the Preference Shares to add to, change or remove any right, privilege, restriction or condition attaching to the Preference Shares as a class or in respect of any other matter requiring the consent of the holders of the Preference Shares may be given in such manner as may then be required by law, subject to a minimum requirement that such approval be given by resolution signed by all the holders of the Preference Shares or passed by the affirmative vote of at least two thirds of the votes cast at a meeting of the holders of the Preference Shares duly called for that purpose. On every poll taken at every meeting of the holders of the Preference Shares as a class, or at any joint meeting of the holders of two or more series of Preference Shares, each holder of Preference Shares entitled to vote thereat shall have one vote in respect of each $1,000 of the issue price of each Preference Share held. Any notice, cheque, notice of redemption or other communication from the Corporation herein provided for shall be sent to the holders of the Preference Shares by first class mail, postage prepaid at their respective addresses appearing on the securities register of this Corporation or, in the event of the address of any such holder not so appearing, then at the last address of such holder known to the Corporation. Accidental failure to give any such notice, notice of redemption of other communication to one or more holders of Preference Shares shall not affect the validity thereof, but, upon such failure being discovered, a copy of the notice, notice of redemption or other communication, as the case may be, shall be sent or delivered forthwith to such holder or holders. Unless otherwise provided herein, any notice, request, certificate or other communication from a holder of Preference Shares herein provided for shall be either sent to the Corporation by first class mail, postage prepaid, or delivered by hand to the Corporation at its registered office.

9. The issue, transfer or ownership of shares is/is not restricted and the restrictions (if any) are as follows:
L'émission, le transfert ou la propriété d'actions est/n'est pas restreint. Les restrictions, s'il y a lieu, sont les suivantes :

The transfer of securities (other than non-convertible debt securities) of the Corporation shall be restricted in that no securityholder shall be entitled to transfer any such security or securities without either:

(a) the approval of the directors of the Corporation expressed by a resolution passed at a meeting of the board of directors or by an instrument or instruments in writing signed by a majority of the directors; or

(b) the approval of the holders of at least a majority of the Class A common shares and the Class B common shares of the Corporation for the time being outstanding expressed by a resolution passed at a meeting of the holders of such shares or by an instrument or instruments in writing signed by the holders of a majority of such shares.

10. Other provisions, (if any):
Autres dispositions, s'il y a lieu :

The following statutes and supplementary letters patent are hereby incorporated into these Articles:

1. Act to incorporate The Consumers' Gas Company of Toronto, 11 Vic. c. 14 (1848), as it may have been amended.

2. Act to extend the powers of The Consumers' Gas Company of Toronto, 16 Vic. c. 142 (1853), as it may have been amended.

3. Act respecting the City of Toronto, the Toronto Street Railway Company and other matters, 39 Vic. c. 63 (S.O. 1875-76), as it may have been amended.

4. Act to Amend the Acts respecting the Consumers' Gas Company of Toronto, 42 Vic. c. 87 (S.O. 1879), as it may have been amended.

5. Supplementary Letters Patent of the Consumers' Gas Company of Toronto dated April 15, 1913, as they may have been amended.

6. Supplementary Letters Patent of the Consumers' Gas Company of Toronto dated April 14, 1931, as they may have been amended.

11. The statements required by subsection 178(2) of the *Business Corporations Act* are attached as Schedule "A".
Les déclarations exigées aux termes du paragraphe 178(2) de la *Loi sur les sociétés par actions* constituent l'annexe A.

12. A copy of the amalgamation agreement or directors' resolutions (as the case may be) is/are attached as Schedule "B".
Une copie de la convention de fusion ou les résolutions des administrateurs (selon le cas) constitue(nt) l'annexe B.

These articles are signed in duplicate.
Les présents statuts sont signés en double exemplaire.

Name and **original signature** of a director or authorized signing officer of each of the amalgamating corporations. Include the name of each corporation, the signatories name and description of office (e.g. president, secretary). **Only a director or authorized signing officer can sign on behalf of the corporation.** / Nom et **signature originale** d'un administrateur ou d'un signataire autorisé de chaque société qui fusionne. Indiquer la dénomination sociale de chaque société, le nom du signataire et sa fonction (p. ex. : président, secrétaire). **Seul un administrateur ou un dirigeant habilité peut signer au nom de la société.**

ENBRIDGE GAS DISTRIBUTION INC.

Names of Corporations / Dénomination sociale des sociétés

By / *Par*

	Cynthia L. Hansen	Director
Signature / Signature	Print name of signatory / Nom du signataire en lettres moulées	Description of Office / Fonction

UNION GAS LIMITED

Names of Corporations / Dénomination sociale des sociétés

By / *Par*

	Cynthia L. Hansen	Director
Signature / Signature	Print name of signatory / Nom du signataire en lettres moulées	Description of Office / Fonction

Names of Corporations / Dénomination sociale des sociétés

By / Par

Signature / Signature	Print name of signatory / Nom du signataire en lettres moulées	Description of Office / Fonction

Names of Corporations / Dénomination sociale des sociétés

By / Par

Signature / Signature	Print name of signatory / Nom du signataire en lettres moulées	Description of Office / Fonction

Names of Corporations / Dénomination sociale des sociétés

By / *Par*

Signature / ***Signature***	Print name of signatory / Nom du signataire en lettres moulées	Description of Office / Fonction

SCHEDULE "A"

ENBRIDGE GAS DISTRIBUTION INC.
(the "Corporation")

STATEMENT OF DIRECTOR UNDER SECTION 178(2) OF THE BUSINESS CORPORATIONS ACT (ONTARIO)

I, Cynthia L. Hansen, of the City of Toronto, Province of Ontario, hereby certify and state that:

1. I am a director of the Corporation, one of the amalgamating corporations, and I have personal knowledge of the matters deposed to in this statement.

2. I have conducted such examinations of the books and records of the Corporation and Union Gas Limited (together, with the Corporation, the "Amalgamating Corporations") as are necessary to enable me to make statements hereinafter set forth. I am satisfied that there are reasonable grounds for believing that:

   a. each of the Amalgamating Corporations is, and the corporation to be formed by their amalgamation (the "Amalgamated Corporation") will be able to pay its liabilities as they become due;

   b. the realizable value of the Amalgamated Corporation's assets will not be less than the aggregate of its liabilities and stated capital of all classes; and

   c. no creditor will be prejudiced by the amalgamation.

DATED this 24th day of December, 2018.

Cynthia L. Hansen
Director, Enbridge Gas Distribution Inc.

UNION GAS LIMITED
(the "Corporation")

STATEMENT OF DIRECTOR UNDER SECTION 178(2) OF THE BUSINESS CORPORATIONS ACT (ONTARIO)

I, Cynthia L. Hansen, of the City of Toronto, Province of Ontario, hereby certify and state that:

1. I am a director of the Corporation, one of the amalgamating corporations, and I have personal knowledge of the matters deposed to in this my statement.

2. I have conducted such examinations of the books and records of the Corporation and Enbridge Gas Distribution Inc. (together, with the Corporation, the "Amalgamating Corporations") as are necessary to enable me to make statements hereinafter set forth. I am satisfied that there are reasonable grounds for believing that:

   a. each of the Amalgamating Corporations is, and the corporation to be formed by their amalgamation ("Amalgamated Corporation") will be able to pay its liabilities as they become due;

   b. the realizable value of the Amalgamated Corporation's assets will not be less than the aggregate of its liabilities and stated capital of all classes; and

   c. no creditor will be prejudiced by the amalgamation.

DATED this 24th day of December, 2018.

Cynthia L. Hansen
Director, Union Gas Limited

SCHEDULE “B”

EXECUTION VERSION

AMALGAMATION AGREEMENT

THIS AMALGAMATION AGREEMENT is made effective the 1st day of January, 2019,

B E T W E E N:

ENBRIDGE GAS DISTRIBUTION INC., a corporation existing under the laws of the Province of Ontario (hereinafter called "**EGD**")

\- and -

UNION GAS LIMITED, a corporation existing under the laws of the Province of Ontario (hereinafter called "**Union Gas**")

RECITALS:

A. EGD and Union Gas have agreed to amalgamate pursuant to the Act;

B. EGD and Union Gas have each made disclosure to the other of their respective assets and liabilities; and

C. it is desirable that the Amalgamation should be effected.

NOW THEREFORE in consideration of the mutual covenants and agreements herein contained and other good and valuable consideration (the receipt and sufficiency of which are hereby acknowledged) the parties agree as follows:

1. Interpretation

In this Agreement (including the recitals hereto), the following terms shall have the following meanings:

1.1 "**Act**" means the *Business Corporations Act* (Ontario);

1.2 "**Agreement**" means this amalgamation agreement;

1.3 "**Amalgamated Corporation**" means the corporation continuing from the amalgamation of the Amalgamating Corporations;

1.4 "**Amalgamating Corporations**" means EGD and Union Gas and "**Amalgamating Corporation**" means either of them;

1.5 "**Amalgamation**" means the amalgamation of the Amalgamating Corporations as contemplated in this Agreement;

1.6 "**Effective Date**" means the date of the amalgamation as set forth in the certificate of amalgamation issued to the Amalgamated Corporation;

1.7 **"EGD Common Shares"** means the common shares in the capital of EGD;

1.8 **"Tax Act"** means the *Income Tax Act* (Canada) and all regulations promulgated thereunder from time to time;

1.9 **"Union Gas Class A Common Shares"** means the Class A common shares in the capital of Union Gas; and

1.10 **"Union Gas Common Shares"** means the common shares in the capital of Union Gas.

Words and phrases used in this Agreement and defined in the Act shall have the same meaning in this Agreement as in the Act unless the context otherwise requires.

2. Agreement to Amalgamate

Each of the Amalgamating Corporations does hereby agree to amalgamate pursuant to the provisions of section 174 of the Act as of the Effective Date and to continue as one corporation on the terms and conditions set out in this Agreement.

3. Name

The name of the Amalgamated Corporation shall be Enbridge Gas Inc.

4. Registered Office

The registered office of the Amalgamated Corporation shall be located at 500 Consumers Road, Toronto, Ontario M2J 1P8.

5. Authorized Capital

The Amalgamated Corporation is authorized to issue an unlimited number of Class A common shares, an unlimited number of Class B common shares, and an unlimited number of Preference Shares. The rights, privileges, restrictions, conditions attaching to each class of shares in the capital of the Amalgamated Corporation are set forth in the attached Schedule A.

6. Number of Directors

The board of directors of the Amalgamated Corporation shall, until otherwise changed in accordance with the Act, consist of a minimum number of 3 and a maximum number of 10 directors.

7. Business

There shall be no restriction on the business which the Amalgamated Corporation is authorized to carry on.

8. Initial Directors and Auditors

The first directors of the Amalgamated Corporation shall be the persons whose names and addresses for service appear below:

Name	Address	Resident Canadian
Cynthia L. Hansen	500 Consumers Road, Toronto, Ontario M2J 1P8	Yes
James E Sanders	500 Consumers Road, Toronto, Ontario M2J 1P8	Yes
David G. Unruh	500 Consumers Road, Toronto, Ontario M2J 1P8	Yes

Such directors shall hold office until the first annual meeting of shareholders of the Amalgamated Corporation or until their successors are elected or appointed.

The current auditors of EGD, PricewaterhouseCoopers LLP, are hereby appointed auditors of the Amalgamated Corporation to hold office until the close of the next annual meeting of shareholders and the directors of the Amalgamated Corporation are authorized to fix their remuneration.

9. Initial Officers

The following persons will be the first officers of the Amalgamated Corporation:

Name	Title
Cynthia L. Hansen	President
James E. Sanders	Senior Vice President, Operations
Mark R. Boyce	Vice President, Law
Michelle R. George	Vice President, Engineering
Malini Giridhar	Vice President, Business Development & Regulatory
Tanya Mushynski	Vice President, Customer Care
James G. Redford	Vice President, Energy Services
Michael G.P. Shannon	Vice President, Storage, Transmission & Integration Management Office
Wendy Zelond	Vice President, Finance
Allen C. Capps	Controller
Maximilian G. Chan	Treasurer
David Taniguchi	Corporate Secretary

10. Amalgamation

On the Effective Date:

10.1 each EGD Common Share that is issued and outstanding immediately prior to the Effective Date will, on and from the Effective Date, be converted into 1.20000000 Class A common shares in the capital of the Amalgamated Corporation;

10.2 each Union Gas Class A Common Share that is issued and outstanding immediately prior to the Effective Date will, on and from the Effective Date, be converted into 4.15097272 Class A common shares in the capital of the Amalgamated Corporation; and

10.3 each Union Gas Common Share that is issued and outstanding immediately prior to the Effective Date will, on and from the Effective Date, be converted into 4.15097272 Class B common shares in the capital of the Amalgamated Corporation.

11. Stated Capital Accounts

The stated capital account in the records of the Amalgamated Corporation shall be:

11.1 for the Class A common shares of the Amalgamated Corporation, an amount equal to the aggregate of the paid up capital (as determined for purposes of the Tax Act) of (i) the issued and outstanding EGD Common Shares, and (ii) the issued and outstanding Union Gas Class A Common Shares; and

11.2 for the Class B common shares of the Amalgamated Corporation, an amount equal to the aggregate of the paid up capital (as determined for purposes of the Tax Act) of the issued and outstanding Union Gas Common Shares.

12. Constating Documents

The by-laws of the Amalgamated Corporation, until repealed, amended or altered, shall be the by-laws of EGD and a copy of these by-laws may be examined at 500 Consumers Road, North York, Ontario, M2J 1P8. In addition, the articles of amalgamation of the Amalgamated Corporation, until amended or altered, shall include or incorporate by reference the provisions of EGD's articles set out in Schedule B.

13. Continuous Disclosure Documents

The Amalgamated Corporation shall prepare and file annual financial statements and an annual information form with Canadian securities administrators in accordance with applicable timelines set forth in Canadian securities laws. Such financial statements and annual information form shall be prepared and filed by the Amalgamated Corporation in the form of audited combined financial statements, in accordance with United States generally accepted accounting principles, and a combined annual information form, for the Amalgamated Corporation's most recently completed financial year, being the year ended December 31, 2018.

14. Termination

This Agreement may, prior to the issuance of a certificate of amalgamation in respect of the Amalgamation, be terminated by the boards of directors of EGD and Union Gas notwithstanding the approval by the shareholders of EGD and Union Gas of the terms and conditions hereof.

15. Filing of Documents

The Amalgamating Corporations shall jointly file with the Director under the Act articles of amalgamation and such other documents as may be required.

16. Governing Law

This Agreement shall be governed by and construed in accordance with the laws of the Province of Ontario and the laws of Canada applicable therein.

17. Entire Agreement

This Agreement constitutes the entire agreement between the parties pertaining to the subject matter of this Agreement. There are no warranties, conditions, or representations (including any that may be implied by statute) and there are no agreements in connection with such subject matter except as specifically set forth or referred to in this Agreement. No reliance is placed on any warranty, representation, opinion, advice or assertion of fact made either prior to, contemporaneous with, or after entering into this Agreement, or any amendment or supplement thereto, by any party to this Agreement or its directors, officers, employees or agents, to any other party to this Agreement or its directors, officers, employees or agents, except to the extent that the same has been reduced to writing and included as a term of this Agreement, and none of the parties to this Agreement has been induced to enter into this Agreement or any amendment or supplement by reason of any such warranty, representation, opinion, advice or assertion of fact. Accordingly, there shall be no liability, either in tort or in contract, assessed in relation to any such warranty, representation, opinion, advice or assertion of fact, except to the extent contemplated above.

18. Further Assurances

Each party hereto shall do and take all such further acts and execute and deliver all such further documents and instruments as may be reasonably required or desirable in order to effect the purpose of this Agreement and carry out its provisions.

19. **Execution in Counterparts**

This Agreement may be executed in identical counterparts, each of which is, and is hereby conclusively deemed to be, an original and such counterparts collectively are to be conclusively deemed to be one and the same instrument. Delivery of counterparts may be effected by electronic transmission.

[Remainder of page intentionally left blank]

IN WITNESS WHEREOF the parties hereto have executed this Agreement.

ENBRIDGE GAS DISTRIBUTION INC.

By: ______________________

Name: Cynthia L. Hansen

Title: Executive Chair

UNION GAS LIMITED

By: ______________________

Name: Cynthia L. Hansen

Title: Executive Chair

SCHEDULE A

Rights, Privileges, Restrictions and Conditions Attaching to Each Class of Shares of the Amalgamated Corporation

A. Class A Common Shares

The Class A common shares, as a class, shall be designated as the Class A common shares and shall have attached thereto the following rights, privileges, restrictions and conditions:

1. Dividends

After payment to the holders of the Preference Shares of the amount or amounts to which they may be entitled, the holders of the Class A common shares shall be entitled to receive, and the Corporation shall pay thereon, any dividends declared by the Corporation on the Class A common shares, if, as and when declared by the directors of the Corporation out of moneys of the Corporation properly applicable to the payment of dividends, in such amounts as may be determined by the directors from time to time, each such dividend to be paid to such holders on such date as may be fixed by the directors at the time of declaration of such dividend. Unless the holders of the Class A common shares and the holders of the Class B common shares consent in writing otherwise, the Class A common shares and the Class B common shares shall rank equally as to dividends on a share for share basis, and all dividends declared by the Corporation shall be declared in equal amounts per share on all Class A common shares and all Class B common shares at the time outstanding, without preference or distinction.

2. Subdivision or Consolidation

No subdivision or consolidation of the Class B common shares or the Class A common shares shall occur unless, simultaneously, the Class A common shares or the Class B common shares, as the case may be, are subdivided or consolidated in the same manner, so as to maintain and preserve the relative rights of the holders of the shares of each of such classes.

3. Liquidation, Dissolution or Winding-up

Upon the liquidation, dissolution or winding-up of the Corporation, whether voluntary or involuntary, or other distribution of the property and assets of the Corporation among its shareholders for the purpose of winding-up its affairs, and after payment to the holders of the Preference Shares of the amount or amounts to which they may be entitled, the holders of the Class A common shares and the holders of the Class B common shares shall be entitled to receive the remaining property and assets of the Corporation and shall be entitled to share equally, on a share for share basis, in all distributions of such property and assets without preference or distinction unless the holders of the Class A common shares and the holders of the Class B common shares consent in writing otherwise.

4. Class A Common Shares to be Voting

The holders of the Class A common shares shall be entitled to receive notice of and to attend all meetings of shareholders of the Corporation, other than separate meetings of the holders of another class or series of shares, and to vote at any such meeting on the basis of one (1) vote for each Class A common share held.

B. Class B Common Shares

The Class B common shares, as a class, shall be designated as the Class B common shares and shall have attached thereto the following rights, privileges, restrictions and conditions:

1. Dividends

After payment to the holders of the Preference Shares of the amount or amounts to which they may be entitled, the holders of the Class B common shares shall be entitled to receive, and the Corporation shall pay thereon, any dividends declared by the Corporation on the Class B common shares, if, as and when declared by the directors of the Corporation out of moneys of the Corporation properly applicable to the payment of dividends, in such amounts as may be determined by the directors from time to time, each such dividend to be paid to such holders on such date as may be fixed by the directors at the time of declaration of such dividend. Unless the holders of the Class A common shares and the holders of the Class B common shares consent in writing otherwise, the Class A common shares and the Class B common shares shall rank equally as to dividends on a share for share basis, and all dividends declared by the Corporation shall be declared in equal amounts per share on all Class A shares and all Class B common shares at the time outstanding, without preference or distinction.

2. Subdivision or Consolidation

No subdivision or consolidation of the Class B common shares or the Class A common shares shall occur unless, simultaneously, the Class A common shares or the Class B common shares, as the case may be, are subdivided or consolidated in the same manner, so as to maintain and preserve the relative rights of the holders of the shares of each of such classes.

3. Liquidation, Dissolution or Winding-up

Upon the liquidation, dissolution or winding-up of the Corporation, whether voluntary or involuntary, or other distribution of the property and assets of the Corporation among its shareholders for the purpose of winding-up its affairs, and after payment to the holders of the Preference Shares of the amount or amounts to which they may be entitled, the holders of the Class A common shares and the holders of the Class B common shares shall be entitled to receive the remaining property and assets of the Corporation and shall be entitled to share equally, on a share for share basis, in all distributions of such property and assets without preference or distinction unless the holders of the Class A common shares and the holders of the Class B common shares consent in writing otherwise.

4. Class B Common Shares to be Voting

The holders of the Class B common shares shall be entitled to receive notice of and to attend all meetings of shareholders of the Corporation, other than separate meetings of the holders of another class or series of shares, and to vote at any such meeting on the basis of one (1) vote for each Class B common share held.

C. Preference Shares

The Preference Shares, as a class, shall be designated as the Preference Shares and shall have attached thereto the following rights, privileges, restrictions and conditions:

1. Directors' Right to Issue in One or More Series

The Preference Shares may be issued at any time or from time to time in one or more series. Before any Preference Shares of a series are issued, the board of directors of the Corporation shall fix the number of Preference Shares that will form such series and shall, subject to the limitations set out in the articles of the Corporation, determine the designation, rights, privileges, restrictions and conditions to be attached to the Preference Shares of such series, the whole subject to the filing with the Director (as defined in the Business Corporations Act (Ontario) (the "**Act**")) of Articles of Amendment containing a description of such series including the rights, privileges, restrictions and conditions determined by the board of directors of the Corporation.

2. Ranking of the Preference Shares

The Preference Shares of each series shall rank on a parity with the Preference Shares of every other series with respect to dividends and return of capital in the event of the liquidation, dissolution or winding up of the Corporation, and shall be entitled to a preference over the Class A common shares and the Class B common shares of the Corporation and over any other shares ranking junior to the Preference Shares with respect to priority in payment of dividends and in the distribution of assets in the event of the liquidation, dissolution or winding-up of the Corporation, whether voluntary or involuntary, or other distribution of the property and assets of the Corporation among its shareholders for the purpose of winding-up its affairs. If any cumulative dividends, whether or not declared, or declared non-cumulative dividends or amounts payable on a return of capital in the event of the liquidation, dissolution or winding up of the Corporation are not paid in full in respect of any series of the Preference Shares, the Preference Shares of all series shall participate rateably in respect of such dividends in accordance with the sums that would be payable on such shares if all such dividends were declared and paid in full, and in respect of such return of capital in accordance with the sums that would be payable on such return of capital if all sums so payable were paid in full; provided, however, that if there are insufficient assets to satisfy in full all such claims as aforesaid, the claims of the holders of the Preference Shares with respect to return of capital shall be paid and satisfied first and any assets remaining thereafter shall be applied towards the payment and satisfaction of claims in respect of dividends. The Preference Shares of any series may also be given such other preferences not inconsistent with the rights, privileges, restrictions and conditions attached to the Preference Shares as a class over the Class A common shares and the Class B common shares of the Corporation and over any other shares ranking junior to the Preference Shares as may be determined in the case of such series of Preference Shares.

3. Preference Shares to be Non-Voting

Except as hereinafter referred to or as required by law or unless provision is made in the Articles relating to any series of Preference Shares that such series is entitled to vote, the holders of the Preference Shares as a class shall not be entitled as such to receive notice of, to attend or to vote at any meeting of the shareholders of the Corporation.

4. Amendment with Approval of Holders of Preference Shares

The rights, privileges, restrictions and conditions attached to the Preference Shares as a class may be added to, changed or removed but only with the approval of the holders of the Preference Shares given as hereinafter specified.

5. Approval of Holders of the Preference Shares

The approval of the holders of the Preference Shares to add to, change or remove any right, privilege, restriction or condition attaching to the Preference Shares as a class or in respect of any other matter requiring the consent of the holders of the Preference Shares may be given in such manner as may then be required by law, subject to a minimum requirement that such approval be given by resolution signed by all the holders of the Preference Shares or passed by the affirmative vote of at least two thirds of the votes cast at a meeting of the holders of the Preference Shares duly called for that purpose. On every poll taken at every meeting of the holders of the Preference Shares as a class, or at any joint meeting of the holders of two or more series of Preference Shares, each holder of Preference Shares entitled to vote thereat shall have one vote in respect of each $1,000 of the issue price of each Preference Share held. Any notice, cheque, notice of redemption or other communication from the Corporation herein provided for shall be sent to the holders of the Preference Shares by first class mail, postage prepaid at their respective addresses appearing on the securities register of this Corporation or, in the event of the address of any such holder not so appearing, then at the last address of such holder known to the Corporation. Accidental failure to give any such notice, notice of redemption of other communication to one or more holders of Preference Shares shall not affect the validity thereof, but, upon such failure being discovered, a copy of the notice, notice of redemption or other communication, as the case may be, shall be sent or delivered forthwith to such holder or holders. Unless otherwise provided herein, any notice, request, certificate or other communication from a holder of Preference Shares herein provided for shall be either sent to the Corporation by first class mail, postage prepaid, or delivered by hand to the Corporation at its registered office.

SCHEDULE B

The following statutes and supplementary letters patent are hereby incorporated into these Articles:

1. *Act to incorporate The Consumers' Gas Company of Toronto*, 11 Vic. c. 14 (1848), as it may have been amended.

2. *Act to extend the powers of The Consumers' Gas Company of Toronto*, 16 Vic. c. 142 (1853), as it may have been amended.

3. *Act respecting the City of Toronto, the Toronto Street Railway Company and other matters*, 39 Vic. c. 63 (S.O. 1875-76), as it may have been amended.

4. *Act to Amend the Acts respecting the Consumers' Gas Company of Toronto*, 42 Vic. c. 87 (S.O. 1879), as it may have been amended.

5. Supplementary Letters Patent of the Consumers' Gas Company of Toronto dated April 15, 1913, as they may have been amended.

6. Supplementary Letters Patent of the Consumers' Gas Company of Toronto dated April 14, 1931, as they may have been amended.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Building Owners and Managers Association of Greater Toronto (BOMA)

Reference: Exhibit A, Tab 2, p 3 of 6

Question:

Please provide a table which shows for each of Union pass-through projects already approved by the Board, their proposed assets in service in 2019, their contribution to the 2019 revenue requirement, the actual expenditure in 2018, and the forecast 2018 expenditure.

Response

Enbridge Gas believes the reference is to Exhibit A, Tab 2, page 4. Please see the table below for the forecast and draft actual Capital Expenditure for 2018 and the forecast Capital Expenditure for 2019 as well as the 2019 Revenue Requirement for the Capital Pass-through Projects.

Particulars ($000's)	Capital Expenditure Approved in Rates 2018	Capital Expenditure Draft Actual 2018	Capital Expenditure Proposed in Rates 2019	Revenue Requirement Proposed in Rates 2019	
Parkway West	-	1,092	1,504	19,227	
Brantford-Kirkwall/ Parkway D	-	-	-	14,874	
2016 Dawn-Parkway Expansion	-	2,464	-	25,059	
Burlington to Oakville	-	1,455	-	5,447	
2017 Dawn-Parkway Expansion	14,267	32,959	6,960	40,916	
Panhandle Reinforcement	30,612	36,454	500	11,715	(1)
Total	44,879	74,424	8,964	117,238	

Notes:
(1) Panhandle Reinforcement project revenue requirement net of incremental project revenue.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Building Owners and Managers Association of Greater Toronto (BOMA)

Reference: Exhibit A, Tab 3, Schedule 1, p3

Question:

(a) Please explain fully why there will be no 2019 rate impacts for potential rate riders associated with the Don River, Kingsville, and Stratford ICM Projects, and that will be dealt with the 2020 rates submission, not the 2019 rates submission (EB-2018-0305).

(b) Why do the Union North zone proposed 2019 rate increases for the direct purchase customers include the ICM impacts, while the sales service customers' proposed 2019 rate increases exclude the ICM impacts?

Response

a) As described at Exhibit B1, Tab 2, Schedule 1, page. 32, the Don River Replacement, Kingsville and Stratford Reinforcement projects have a negative revenue requirement[1] in 2019, which is the in-service year of the projects. Enbridge Gas proposes to net the negative revenue requirement in the in-service year with the revenue requirement in the second year and defer the ICM impact until the second year of the project. This proposal reduces rate volatility and the impact on customers while also ensuring the negative revenue requirement of the first year accrues to the benefit of customers.

Enbridge Gas is seeking approval of the proposed ICM projects in the current application. If approved, Enbridge Gas proposes to calculate the 2020-2023 ICM unit rates for the 2019 approved ICM projects as part of each respective annual rate proceedings based on the annual revenue requirements approved in this application and the updated forecast billing units.

b) The bill impacts for both direct purchase and sales services customers, as provided at Exhibit A, Tab 3, Schedule 1, page 3, are inclusive of ICM projects.

[1] The negative revenue requirement results from utility tax timing differences as the capital cost allowance deductions in arriving at taxable income exceeds to provision of book depreciation in the year.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Building Owners and Managers Association of Greater Toronto (BOMA)

Reference: Exhibit A, Tab 3, Schedule 1, p4

Question:

Please provide copies of the most recent three years of customer satisfaction surveys that EGD and Union have conducted.

Response

The customer engagement reports supporting this 2019 rates application for Enbridge Gas are provided at Exhibit D. As per the MAADs decision, Enbridge Gas will file a consolidated USP in 2021. In support of the USP, the company will conduct a customer engagement survey which will be filed as part of the 2021 rate application.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Building Owners and Managers Association of Greater Toronto (BOMA)

Reference: Conditions of Service; Exhibit A, Tab 3, Schedule 1

Question:

The reference to the conditions of service state that they are meant to be guidelines, and not to override any item in any contract EGD has with the customers.

(a) Do the guidelines have any legal effect, in EGD's view, either for contract customers or general service customers?

(b) Have they ever been relied upon in any legal claim, launched against EGD?

(c) Has the Board ever approved EGD's Conditions of Service? In what proceeding(s)?

(d) Section 2.4 GS – "Depletion or shortage of gas supply" – What if EGD were judged to be imprudent in its gas purchase decisions? Is it still exonerated by this clause?

Response

a) Enbridge Gas must comply with its Customer Service Policy as set out in its Conditions of Service, as required by section 8.3.1 of the Board's *Gas Distribution Access Rule* (GDAR). As noted in the reference, the Conditions of Service do not supersede contractual terms in place with customers, however, includes terms and conditions set out in the EGD rate zone's Rate Handbook.

b) Legacy EGD received only one legal claim that relied upon the Conditions of Service, to the best of our knowledge. This was in relation to a meter reading issue that was ultimately resolved with the customer and there was no determination that EGD was in breach of its Conditions of Service.

c) The revision history of the Conditions of Service is set out on pages 2 to 5 of Exhibit A1, Tab 5, Schedule 1. For each revision, EGD filed the revised Conditions of Service with the Board in accordance with section 8.5 of the GDAR. Board approval of the Conditions of Service is not required for each revision.

d) In the event of an interruption or cessation of gas deliveries, Enbridge Gas would have to consider all of the circumstances in order to determine whether to declare a force majeure. Force majeure events typically are events that are beyond the control of the Company, as noted and listed in section 2.4 of the Conditions of Service.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Building Owners and Managers Association of Greater Toronto (BOMA)

Reference: General Definition of Mains

Question:

Please provide a definition of EGD's mains. What criteria are utilized, for example, pressure, diameter pipe, function or purpose, length, or other factors. Please specify what other factors come into play.

Response

The EGD rate zone’s mains are described as *“the connection between the entry of natural gas into EGD’s system and the delivery of gas to where energy is used by customers*.” This definition can be found at section 5.2, page 105, in the EGD rate zone’s AMP which is filed at Exhibit C1, Tab 2, Schedule 1.

Mains are categorized by material, namely Steel and Plastic. Steel Mains are further divided into Integrity and Steel Mains.

The definition of these assets can be found at section 5.2 in the EGD rate zone’s AMP which is filed at Exhibit C1, Tab 2, Schedule 1. Please refer to sub-section 5.2.4, page 113 for Integrity Mains, sub-section 5.2.5, page 116 for Distribution Steel Mains and sub-section 5.2.6 page 131 for Distribution Plastic Mains.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Building Owners and Managers Association of Greater Toronto (BOMA)

Reference: Union Gas Conditions of Service; Exhibit A, Tab 5, Schedule 3, p5

Question:

Please provide a further definition of mains, or its equivalent, in addition to "The pipe that is used to carry gas to a service".

Response

Mains are the pipe that serves as a common source of supply for more than one service. A service connects the main to the customer premises. Mains are generally within the public right of way, or within an easement, whereas service piping can be included on private property to serve the individual customer.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Building Owners and Managers Association of Greater Toronto (BOMA)

Reference: Exhibit B1, Tab 1, Schedule 1, p9

Question:

a) Please provide details on which distribution related costs are recovered through EGD's commodity, transportation, and load balancing charges.
b) Please describe each of these costs, and indicate in which of the Company's commodity, transportation, and load balancing charges contain each of the described costs.
c) Please provide a breakdown of that number into the number for each of the pass-through projects which make it up. Please provide details of the treatment of each of the pass-through projects in the 2019 rates proposal.

Response

a-b) Please see Exhibit I.FRPO.1 to 3.

d) Please note that there are no project pass through costs that are recovered through the Company's gas supply commodity, transportation, and load balancing charges.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Building Owners and Managers Association of Greater Toronto (BOMA)

Reference: Exhibit B1, Tab 1, Schedule 1, p15

Question:

What are the accounting policy changes, if any, that result from the merger, and which will be entered in the Accounting Policy Changes Deferral Account in 2019?

Response

Consistent with direction from the Board in its MAADs Decision[1], Enbridge Gas is in the process of evaluating the revenue requirement impact of accounting changes resulting from amalgamation. Accounting changes that may impact revenue requirement include changes related to pensions, capitalization policy and depreciation.

[1] EB-2017-0306/0307, MAADs Decision and Order, Page 46.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Building Owners and Managers Association of Greater Toronto (BOMA)

Reference: Exhibit B1, Tab 1, Schedule 1, p19

Preamble: *"The MAADs Decision directed Enbridge Gas to add rate base and depreciation associated with Union's capital pass-through projects to the 2013 Board-approved rate base and depreciation in determining the eligible incremental capital amount for the Union service territory. As a result, Enbridge Gas proposes to fix the capital pass-through revenue requirement in rates (as described in Section 4.2.1) and discontinue the use of the capital pass-through deferral accounts, except for the purposes of capturing utility tax timing variances".*

Question:

a) Please provide a further explanation for Union's decision to "fix" the capital pass-through revenue requirement in rates and how that follows from the first sentence in the quoted excerpt from its evidence.

b) Please provide the revenue requirement for each of 2014-2018, which underpin the amounts shown in Table 2.

c) Please provide the revenue requirement for 2019 which underpins the numbers in the 2019 column.

d) Please explain why the amount of $36,415M is shown for each of 2019 through 2023 in line 7 of Table 7.

e) What are the actual utility tax timing differences for 2018?

f) Please provide an explanation for the link between the MAADs decision to include the rate base and depreciation for each of Union's six capital pass-through projects in the calculation to determine the eligible incremental capital capacity, and Union's decision to reverse the benefits in the years 2019-2023.

Response

a) Please see to Exhibit I.STAFF.8, part a).

b) Enbridge Gas assumes that the question is referencing Exhibit B1, Tab 1, Schedule 1, Table 6 and not Table 2.

Union's Capital Pass-through Projects
Actual Revenue Requirement
Union's 2014-2018 IRM
Updated for Exhibit I.BOMA.14

Line No.	Particulars ($000's)	2014	2015	2016	2017	Forecast 2018	Total
		(a)	(b)	(c)	(d)	(e)	(f)
1	Parkway West	(751)	6,039	15,045	16,656	18,590	55,579
2	Brantford-Kirkwall/ Parkway D	-	502	13,127	14,569	14,533	42,731
3	2016 Dawn-Parkway Expansion	-	(334)	2,381	22,825	24,311	49,182
4	Burlington to Oakville	-	-	335	4,824	5,207	10,367
5	2017 Dawn-Parkway Expansion(1)	-	-	(1,191)	11,454	34,349	44,612
6	Panhandle Reinforcement(2)	-	-	-	83	10,544	10,627
7	Total	(751)	6,207	29,697	70,411	107,534	213,098

Notes:
(1) 2017 Dawn-Parkway Expansion net of revenue allocated to deferral account related to sale of excess capacity of 30,393 GJ/d.
(2) Panhandle Reinforcement revenue requirement is net of incremental revenue.

c) Enbridge Gas assumes that the question is referring to Exhibit B1, Tab 1, Schedule 1, Table 7. Please refer to Exhibit B1, Tab 1, Schedule 1, Table 10 for the revenue requirement included in 2019 proposed rates.

d) Enbridge Gas assumes the question is referencing Line 8 and not Line 7 of Table 7.

The 2019 forecast utility tax timing difference amount of ($36,415) thousand is shown for each year of the 2019-2023 deferred rebasing period on Line 8 of Table 7 consistent with Enbridge Gas's rate design proposal, detailed in Section 4.2.1 of Exhibit B, Tab 1, Schedule 1, to do a one-time adjustment to include the forecast

2019 capital pass-through revenue requirement (inclusive of the 2019 utility tax timing difference) in rates for the deferred rebasing term. For further details please refer to Exhibit I.STAFF.8.

e) Please see Exhibit I.LPMA.2, part a).

f) Please see Exhibit I.STAFF.8, part a).

ENBRIDGE GAS INC.
Answer to Interrogatory from
Building Owners and Managers Association of Greater Toronto (BOMA)

Reference: One-Time Adjustment of Capital Pass-Through Projects; Exhibit B1, Tab 1, Schedule 1, p26; Exhibit F1, Tab 2, Rate Order, Schedule 16, pp4-5

Question:

Please provide the underlying calculation to support EGD's proposed one-time adjustment to rates "in lieu of continuing to make Y-factor adjustments to the revenue requirement of the Projects during the 2019-2023 deferral rebasing period". What would be the annual adjustments over the 2019-2023 period if the one-time payment approach were not used?

Response

Please see Exhibit F1, Tab 2, Rate Order, Schedule 16, pages 4 to 5 for the calculation supporting the one-time adjustment for Union's capital pass-through projects.

Please see Exhibit I.SEC.6, Attachment 1 for the 2019-2023 forecast annual revenue requirement of Union's capital pass-through projects.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Building Owners and Managers Association of Greater Toronto (BOMA)

Reference: Exhibit B1, Tab 1, Schedule 1, p28; Exhibit F1, Tab 2, Rate Order, Schedule 16, p28

Question:

Please expand on the explanation given for building into rates the surplus Dawn-Parkway capacity of 30,393 GJ/day. Please provide the excerpt from the 2017 Dawn-Parkway proceeding, cited at line 18, related to the crediting of revenue earned to Deferral Account 179-144. Please confirm that all of the surplus capacity in question has been sold as of November 1, 2018, and for what term(s).

Response

Please see Exhibit I.STAFF.11 part a).

Enbridge Gas has adjusted Rate M12 demand changes to account for the incremental revenue associated with the 30,393 GJ/d of surplus capacity that has been sold long term under Rate M12.

The excerpt from the 2017 Dawn-Parkway Settlement Agreement (EB-2015-0200) starting at p.23 states:

> In the interest of Settlement, Union will include in the deferral account balance a credit of $1.34 million related to the 30,393 GJ/d of surplus capacity. As addressed at B.ANE.18, the $1.34 million is the maximum annual revenue that could be realized from the sale of long-term firm surplus capacity effective November 1, 2017 (30,393 GJ/d x $0.121/GJ/d x 365 days). Variances in the actual revenue generated from the surplus capacity to the $1.34 million will also be recorded in the deferral account, and will be subject to review at the time of disposition of the account.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Building Owners and Managers Association of Greater Toronto (BOMA)

Reference: Exhibit C1, Tab 1, Schedule 1; Utility System Plan/EGD, pp7-8

Question:

For EGD's rate zone, please provide definition of mains system. For Union's two rate zones, please provide the definition and categorization of system stations, length of mains, and size of fleet.

Response

Mains System – EGD Rate Zone

Mains system are defined as distribution piping which "includes EGD-owned and maintained piping including pipe, valves, all pipe appurtenances, services, and risers installed up to Customer Asset components and upstream of the meter." This definition can be found at Section 5.2 in the EGD rate zone's AMP, filed at Exhibit C1, Tab 2, Schedule 1, page 105.

System Stations – Union Rate Zone

As defined at section 5.4.2, page 87 in the Union rate zones' AMP, filed at Exhibit C1, Tab 3, Schedule 1, System stations are:

> "typically above grade facilities designed to reduce the operating pressure of natural gas pipeline systems through pressure control and over pressure protection. These facilities are used to transmit and/or distribute natural gas to reduced operating pressure pipeline systems which supply natural gas to cities and towns. System station components consist of piping, meters, regulators, valves, filters, separators, heaters, odourant, controls, and in some cases, structures. System station components can vary greatly depending on the station's application and design complexity. At Union, system stations are broken down into subclasses which drive design and operating practices as well as inspection requirements."

Further categorization can be found in table 5.4.2.2.1, page 88.

The table below shows a revised inventory of System Stations by the Union North and South rate zones.

Station Subclass	Operating Parameters		Systems Station Inventory		
	Maximum Inlet Pressure	Inlet Size	Union North Rate Zone	Union South Rate Zone	Total
Subclass A	Over 3,450 kPa	NPS 3 and over	103	187	290
	Any Pressure	NPS 8 and over			
Subclass B	Over 3,450 kPa	NPS 2	289	476	765
	3,450 kPa and Under	NPS 3 to NPS 6			
Subclass C	3,450 kPa and Under	NPS 2	723	1,191	1,914
	All Pressures	Less than NPS 2			
Total Number of Stations					2,969

Length of mains – Union Rate Zone

Enbridge Gas's assets in the Union rate zones include over 70,000 km of distribution, transmission, and storage pipelines. For more details on the Union rate zones' length of mains, please refer to page 8 of the USP filed at Exhibit C1, Tab 1, Schedule 1.

The length of mains is greater than 19,000 km for the Union North rate zone, and greater than 51,000 km for the Union South rate zone.

Size of fleet – Union Rate Zone

Enbridge Gas owns approximately 1,280 vehicles, trailers, and equipment across Ontario from Windsor to Cornwall to Kenora to support its operational business needs. For more details on the size of fleet, please refer to section 5.4.8.2, page 120 in the Union rate zones' AMP filed at Exhibit C1, Tab 3, Schedule 1.

The table below shows a revised inventory of vehicle type by the Union North and South rate zones.

Vehicle Type	Example	Union South Rate Zone	Union North Rate Zone	Total Inventory
Cars	Ford Focus, Escape	36	14	50
Light Trucks	Vans, Pick-ups, USR 1 Trucks	304	149	453
Medium Trucks	USR 2 & USR 3, Cube Vans, etc.	165	68	233
Heavy Trucks	Dump Trucks	31	12	43
	Totals	536	243	779

ENBRIDGE GAS INC.
Answer to Interrogatory from
Building Owners and Managers Association of Greater Toronto (BOMA)

Reference: Exhibit C1, Tab 1, Schedule 1; Utility System Plan/EGD, p1

Question:

a) Where in the US Northeast does Union see the most likely new market for gas transmitted through the Dawn-Trafalgar system?

b) With respect to future growth in the US Northeast market for ex-franchise service, please assess the competitive position of gas transmitted through DT and into the US at Union/EGD exit points, in light of new or expanded pipelines from Utica/Marcellus to US Northeast.

Response

a) The potential growth of the Dawn Parkway System for U.S. Northeast customers primarily comes from natural gas demand growth for utilities located in Maine, Vermont, New Hampshire, Massachusetts, Connecticut, Rhode Island, and New York.

b) Dawn is well positioned as a source of supply for U.S. Northeast customers that are able to secure transportation on the Portland Natural Gas Transmission System and the Iroquois Gas Transmission System. These pipelines represent major routes for customers in the U.S. Northeast to transport gas supplies directly to their delivery areas or to other U.S. Northeast pipelines that connect to their delivery areas. Given challenges faced by several projects to successfully build new pipeline capacity to serve demand growth in the U.S. Northeast, expansion of existing capacity along major pipeline routes into the U.S. Northeast is an attractive option for these customers. For example, a current pipeline expansion project on the Portland Natural Gas Transmission System, called the Portland X-Press Project, has resulted in new and existing U.S. Northeast and Eastern Canadian customers contracting for incremental capacity from the Dawn Hub beginning in 2018 - 2020.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Building Owners and Managers Association of Greater Toronto (BOMA)

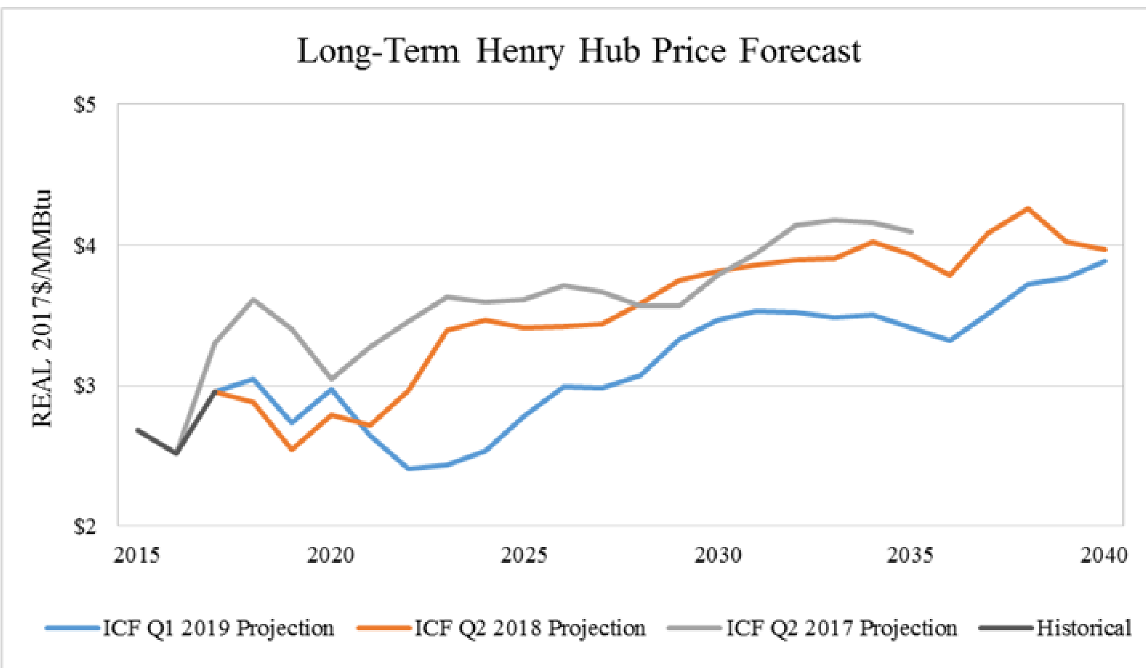
Reference: Exhibit C1, Tab 1, Schedule 1; Utility System Plan/EGD, p11

Question:

Please provide ICF gas price projection/study for 2018 and, if available, for 2019.

Response

ICF has provided the updated chart which includes their Q1 2019 projection below.



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ENBRIDGE GAS INC.
Answer to Interrogatory from
Building Owners and Managers Association of Greater Toronto (BOMA)

Reference: Exhibit C1, Tab 1, Schedule 1; Utility System Plan/EGD, p18

Question:

What share of revenue from sales of storage by the unregulated storage entity to third parties does the regulated utility obtain? What is the rationale for that number?.

Response

Revenue from the sale of excess utility storage space is recorded in Deferral Account No. 179-70 of which 90% is shared with ratepayers.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Building Owners and Managers Association of Greater Toronto (BOMA)

Reference: Exhibit C1, Tab 1, Schedule 1; Utility System Plan/EGD, p21

Question:

a) What percentage of EGD and Union rate zone workforce are unionized? How many positions in which unions? How are collective bargaining results incorporated into the OM&A budgets?

b) Please describe, for each of EGD and Union:

(i) the extent to which labour costs are capitalized into the various capital projects;
(ii) for 2019, how many FTEs (positions) will be capitalized;
(iii) what are the impacts of capitalization for both the capital and OM&A budget;
(iv) what principles or guidelines do EGD and Union observe in deciding how much labour cost to capitalize? Please provide any published relevant Accounting Principles.

Response

a) Enbridge Gas has approximately 4,600 employees (headcount), and approximately 1,490 (582 legacy EGD/908 legacy Union) unionized employees, which represents a 32% unionized workforce. In terms of collective bargaining results being incorporated into the OM&A budgets, a market analysis of other recent collective bargaining agreements settled in Ontario is done, and is then reviewed with finance to ensure the general wage increase is appropriate.

b)

i) Please see to Exhibit I.STAFF.32, part (c).
ii) FTE information is not tracked at the O&M vs. Capital level. As noted in Exhibit I.STAFF.32 (c), in the case of EGD, overheads related to labour cost are determined by the degree of support each functional group provides to capital projects, representing a portion of an FTE.
iii) The table below summarizes the capitalized overhead for EGD and UG based on the 2019 budget.

2019 Budget	EGD	UG	Total
Capitalized Overhead	151M	82M	233M

iv) Please see Exhibit I.STAFF.32, part c).

ENBRIDGE GAS INC.
Answer to Interrogatory from
Building Owners and Managers Association of Greater Toronto (BOMA)

Reference: Exhibit C1, Tab 1, Schedule 1; Utility System Plan/EGD, p28

Question:

For each of EGD and Union:

(a) Please provide copies of the business cases for each capital project included in the 2019 capital budget, or a reference to the business case provided in the evidence, including the breakdown into system access, system renewal, system service, and general plant.

(b) Which of the projects will require Leaves to Construct from the Board?

(c) Please provide a prioritized list, eg. from 1 to 20 of the projects listed in response to subsection (a);

(d) Please indicate the priority ranking, within that list, of the projects for which ICM financing is requested in 2019.

Response

(a) For projects and programs greater than $2M forming part of the EGD Asset Plan, detailed information can be found at Appendix 7. 2-1 to Appendix 7.2-9.[1]

The details for projects and programs greater than $2M that are part of the Union Asset Plan can be found in Appendix D.[2]

b-d) Please see Attachment 1 and Attachment 2. The EGD capital plan was optimized using the Asset Management Process (outlined in Section 4.2). The result addresses the organization's known asset risks and opportunities requiring action over the next 10 years. The details of how EGD completed its optimization are

[1] Exhibit C1, Tab 2, Schedule 1, pages 400 -1459.
[2] Exhibit C1, Tab 3, Schedule 1, page 185.

included in Section 4.1.3.4 Optimize Portfolio Based on Asset Management Principles (p. 71 - 74). Please refer to the Asset Management Core Process steps Risk Management (Section 4.2.1 p. 79), Solution Planning (Section 4.2.2 p. 83) and Portfolio Optimization (Section 4.2.3 p. 84).[3] It should be noted that Enbridge Gas in the EGD rate zone optimizes capital by maximizing the risk reduction of a portfolio of work subject to a constraint such as cost. As such, it is not possible to assign a numerical ranking to each business case. Through the optimization process the Asset Investment Planning Tool seeks to drive the efficient allocation of capital over the 10 year portfolio and will place projects in that 10 year horizon to meet this objective. All of the business cases included in the Asset Plan, and provided in this response, represent work that this organization considers necessary to do and the Asset Management Process allows this work to be assigned to a specific year.

The Union capital plan prioritized investments based on the Asset Management approach as outlined in Section 4.2.1.1.3 Risk Management (p. 51to54) and Section 4.2.1.1.4 Project Prioritization and Selection (p. 55 to 58).[4]

In Exhibit C1, Tab 3, Schedule 1, page 56, the Union AMP outlines the need for a mix of high-priority and lower-priority projects allowing for adjustments to be made in the portfolio as circumstances change. For example, when high-risk or emergency situations arise, the ability to reallocate funding from lower-priority work is beneficial. Maintaining some lower-priority work in the portfolio also allows the organization to be proactive in mitigating risks that if repeatedly deferred will become more significant risks until such time as the organization is compelled to address them in a reactive fashion.

Attachment 1 and 2 include the following information:

- Business Case ID/Unique Identifier
- Investment Category
- Asset Class/Asset Category
- Asset Program/Portfolio
- Project Name/Description
- ICM Eligible
- Mandatory
- Lifetime Risk Return on Investment / Priority
- Spend profile
- Potential for LTC

[3] Exhibit C1, Tab 2, Schedule 1.
[4] Exhibit C1, Tab 3, Schedule 1.

Project Listing for EGD (2019-2023)

Business Case ID	Investment Category	Asset Class	Asset Program	Project Name	ICM - Eligible	Mandatory	LRROI (%)	2019 ($)	2020 ($)	2021 ($)	2022 ($)	2023 ($)	Potential for LTC
2367	System Access	Business Development	NGV	NGV Rental Compressors - Ex Transit - (Until 2020)		N	89	2,600,000	5,600,000	-	-	-	
2368	System Access	Business Development	NGV	NGV Rental VRA's - (Until 2025)		N	100	250,000	254,325	258,725	263,201	267,754	
2369	System Access	Business Development	NGV	NGT Maintenance Capital for company/fleet NG refueling stations - (Until 2020)		N	178	405,000	412,007	-	-	-	
8550	System Access	Business Development	NGV	NGT Rental Compressors - Ex Transit - (2021 to 2028)		N	118	-	-	4,500,000	3,000,000	3,000,000	
9552	System Access	Business Development	NGV	NGT Existing customer Maintenance Capital - (Until 2026)		N	108	281,311	286,178	291,128	296,165	301,289	
9553	System Access	Business Development	NGV	NGT Maintenance Capital for company/fleet NG refueling stations (2021 to 2028)		N	155	-	-	419,134	461,773	294,530	
19223	System Access	Business Development	NGV	Establishing Hydrogen (H2) Interoperability Criteria		N	100	1,200,000	365,000	-	-	-	
2986	System Renewal	Customer Assets	Regulator Refit	2019 Regulator & Meter Exchanges, Replacements, Resets, Vent Aways		Y	162	17,290,020	-	-	-	-	
2987	System Renewal	Customer Assets	Regulator Refit	2020 Regulator & Meter Exchanges, Replacements, Resets, Vent Aways		Y	162	-	17,696,396	-	-	-	
2988	System Renewal	Customer Assets	Regulator Refit	2021 Regulator & Meter Exchanges, Replacements, Resets, Vent Aways		Y	162	-	-	17,884,761	-	-	
3010	System Renewal	Customer Assets	Remediation - Customer Assets	2019 HP-XHP Remediation		Y	189	901,614	-	-	-	-	
3012	System Renewal	Customer Assets	Remediation - Customer Assets	2020 HP-XHP Remediation		Y	185	-	917,211	-	-	-	
3016	System Renewal	Customer Assets	Remediation - Customer Assets	2019 Commercial / Industrial LPDMS Program		Y	226	652,706	-	-	-	-	
3021	System Renewal	Customer Assets	Remediation - Customer Assets	2020 Commercial / Industrial LPDMS Program		Y	226	-	652,706	-	-	-	
3030	System Renewal	Customer Assets	Remediation - Customer Assets	2021 Commercial / Industrial LPDMS Program		Y	226	-	-	652,706	-	-	
3032	System Renewal	Customer Assets	Remediation - Customer Assets	2019 Service Extension Sample Removals		N	34	55,000	55,000	-	-	-	
3035	System Access (30%) / System Renewal (70%)	Customer Assets	Meters - Capital Purchase Program	2019 Meter Purchases		Y	113	20,621,317	-	-	-	-	
3036	System Access (30%) / System Renewal (70%)	Customer Assets	Meters - Capital Purchase Program	2020 Meter Purchases		Y	113	-	22,827,885	-	-	-	
3037	System Access (30%) / System Renewal (70%)	Customer Assets	Meters - Capital Purchase Program	2021 Meter Purchases		Y	113	-	-	21,353,189	-	-	
3626	System Renewal	Customer Assets	Remediation - Customer Assets	2021 Farm tap Program		Y	40	-	-	101,400	-	-	
3627	System Renewal	Customer Assets	Remediation - Customer Assets	2019 Farm tap Program		Y	40	856,941	-	-	-	-	
3628	System Renewal	Customer Assets	Remediation - Customer Assets	2020 Farm tap Program		Y	40	-	856,615	-	-	-	
8501	System Access (30%) / System Renewal (70%)	Customer Assets	Meters - Capital Purchase Program	2018 Meter shop Machinery Upgrades		Y	261	40,000	-	-	-	-	
8529	System Renewal	Customer Assets	Regulator Refit	2022 Regulator & Meter Exchanges, Replacements, Resets, Vent Aways		Y	165	-	-	-	18,270,259	-	
8531	System Renewal	Customer Assets	Regulator Refit	2023 Regulator & Meter Exchanges, Replacements, Resets, Vent Aways		Y	162	-	-	-	-	18,625,418	
8542	System Renewal	Customer Assets	Remediation - Customer Assets	2022 Commercial / Industrial LPDMS Program		Y	226	-	-	-	357,749	-	
8543	System Renewal	Customer Assets	Remediation - Customer Assets	2023 Commercial / Industrial LPDMS Program		Y	226	-	-	-	-	357,749	
8570	System Access (30%) / System Renewal (70%)	Customer Assets	Meters - Capital Purchase Program	2022 Meter Purchases		Y	137	-	-	-	23,592,268	-	
8571	System Access (30%) / System Renewal (70%)	Customer Assets	Meters - Capital Purchase Program	2023 Meter Purchases		Y	113	-	-	-	-	24,687,621	
8803	System Renewal	Customer Assets	Remediation - Customer Assets	2022 Farm tap Program		Y	40	-	-	-	103,155	-	
8804	System Renewal	Customer Assets	Remediation - Customer Assets	2023 Farm tap Program		Y	40	-	-	-	-	104,939	
9141	System Renewal	Customer Assets	Remediation - Customer Assets	2019 Assets Downstream of Bulk Meters		Y	144	443,000	-	-	-	-	
9142	System Renewal	Customer Assets	Remediation - Customer Assets	2020 Assets Downstream of Bulk Meters		Y	144	-	400,000	-	-	-	
9143	System Renewal	Customer Assets	Remediation - Customer Assets	2021 Assets Downstream of Bulk Meters		Y	144	-	-	203,410	-	-	
9144	System Renewal	Customer Assets	Remediation - Customer Assets	2022 Assets Downstream of Bulk Meters		Y	144	-	-	-	203,410	-	
9167	System Access (30%) / System Renewal (70%)	Customer Assets	Meters - Capital Purchase Program	2019 Meter shop Machinery Upgrades		N	123	175,000	-	-	-	-	

Project Listing for EGD (2019-2023)

Business Case ID	Investment Category	Asset Class	Asset Program	Project Name	ICM - Eligible	Mandatory	LRROI (%)	2019 ($)	2020 ($)	2021 ($)	2022 ($)	2023 ($)	Potential for LTC
9168	System Access (30%) / System Renewal (70%)	Customer Assets	Meters - Capital Purchase Program	2020 Meter shop Machinery Upgrades		N	127	-	225,000	-	-	-	
9169	System Access (30%) / System Renewal (70%)	Customer Assets	Meters - Capital Purchase Program	2021 Meter shop Machinery Upgrades		Y	123	-	-	90,000	-	-	
9170	System Access (30%) / System Renewal (70%)	Customer Assets	Meters - Capital Purchase Program	2022 Meter shop Machinery Upgrades		N	123	-	-	-	110,000	-	
9172	System Access (30%) / System Renewal (70%)	Customer Assets	Meters - Capital Purchase Program	2023 Meter shop Machinery Upgrades		N	123	-	-	-	-	245,000	
17966	System Renewal	Customer Assets	Remediation - Customer Assets	2023 Assets Downstream of Bulk Meters		Y	144	-	-	-	-	203,410	
3402	System Access	Customer Growth	Apartment Ensuite - New Construction	Area 10 - Apartment Ensuite - New Construction		Y	109	2,321,778	2,408,584	2,459,123	2,433,377	2,431,158	
3405	System Access	Customer Growth	Apartment Traditional - New Construction	Area 10 - Apartment Traditional - New Construction		Y	1257	2,079	2,156	2,202	2,179	2,177	
3406	System Access	Customer Growth	Commercial - New Construction	Area 10 - Commercial - New Construction		Y	37	5,700,134	5,913,249	6,037,326	5,974,117	5,968,670	
3408	System Access	Customer Growth	Residential - Replacement	Area 10 - Residential - Replacement		Y	24	6,852,731	7,108,939	7,258,105	7,182,115	7,175,566	
3700	System Access	Customer Growth	Residential - New Construction	Area 10 - Residential - New Construction		Y	291	852,491	884,364	902,920	893,467	892,652	
3720	System Access	Customer Growth	Industrial - New Construction	Area 10 - Industrial - New Construction		Y	0	31,186	32,352	33,030	32,685	32,655	
3722	System Access	Customer Growth	Apartment Ensuite - New Construction	Area 20 - Apartment Ensuite - New Construction		Y	724	11,360	11,784	12,032	11,906	11,895	
3724	System Access	Customer Growth	Apartment Traditional - New Construction	Area 20 - Apartment Traditional - New Construction		Y	625	459	476	486	481	481	
3726	System Access	Customer Growth	Commercial - New Construction	Area 20 - Commercial - New Construction		Y	143	2,173,646	2,254,914	2,302,228	2,278,125	2,276,047	
3727	System Access	Customer Growth	Industrial - New Construction	Area 20 - Industrial - New Construction		Y	0	299,503	310,701	317,221	313,899	313,613	
3729	System Access	Customer Growth	Residential - New Construction	Area 20 - Residential - New Construction		Y	226	5,807,199	6,024,317	6,150,724	6,086,328	6,080,778	
3730	System Access	Customer Growth	Residential - Replacement	Area 20 - Residential - Replacement		Y	41	875,836	908,581	927,646	917,934	917,097	
3731	System Access	Customer Growth	Apartment Ensuite - New Construction	Area 30 - Apartment Ensuite - New Construction		Y	156	608,409	631,156	644,400	637,653	637,072	
3735	System Access	Customer Growth	Commercial - New Construction	Area 30 - Commercial - New Construction		Y	63	3,572,436	3,706,002	3,783,764	3,744,149	3,740,735	
3736	System Access	Customer Growth	Industrial - New Construction	Area 30 - Industrial - New Construction		Y	0	148,523	154,076	157,309	155,662	155,520	
3738	System Access	Customer Growth	Residential - New Construction	Area 30 - Residential - New Construction		Y	138	11,031,571	11,444,016	11,684,144	11,561,815	11,551,273	
3739	System Access	Customer Growth	Residential - Replacement	Area 30 - Residential - Replacement		Y	14	4,344,294	4,506,717	4,601,281	4,553,107	4,548,956	
3740	System Access	Customer Growth	Apartment Ensuite - New Construction	Area 40 - Apartment Ensuite - New Construction		Y	392	46,688	48,433	49,449	48,932	48,887	
3744	System Access	Customer Growth	Commercial - New Construction	Area 40 - Commercial - New Construction		Y	178	1,157,598	1,200,878	1,226,076	1,213,240	1,212,133	
3747	System Access	Customer Growth	Residential - New Construction	Area 40 - Residential - New Construction		Y	248	4,776,794	4,955,387	5,059,365	5,006,395	5,001,830	
3748	System Access	Customer Growth	Residential - Replacement	Area 40 - Residential - Replacement		Y	32	4,904,971	5,088,356	5,195,124	5,140,733	5,136,046	
3753	System Access	Customer Growth	Commercial - New Construction	Area 50 - Commercial - New Construction		Y	168	721,116	748,077	763,773	755,777	755,088	
3756	System Access	Customer Growth	Residential - New Construction	Area 50 - Residential - New Construction		Y	164	5,906,023	6,126,836	6,255,394	6,189,902	6,184,258	
3757	System Access	Customer Growth	Residential - Replacement	Area 50 - Residential - Replacement		Y	30	3,590,204	3,724,433	3,802,582	3,762,771	3,759,340	
3758	System Access	Customer Growth	Apartment Ensuite - New Construction	Area 60 - Apartment Ensuite - New Construction		Y	345	21,720	22,532	23,005	22,764	22,743	
3759	System Access	Customer Growth	Apartment Traditional - New Construction	Area 60 - Apartment Traditional - New Construction		Y	4989	1,765	1,831	1,869	1,849	1,848	
3761	System Access	Customer Growth	Commercial - New Construction	Area 60 - Commercial - New Construction		Y	42	4,405,692	4,570,411	4,666,311	4,617,456	4,613,246	
3762	System Access	Customer Growth	Industrial - New Construction	Area 60 - Industrial - New Construction		Y	0	2,412,263	2,502,452	2,554,961	2,528,211	2,525,906	
3764	System Access	Customer Growth	Residential - New Construction	Area 60 - Residential - New Construction		Y	115	10,807,094	11,211,146	11,446,388	11,326,548	11,316,220	
3765	System Access	Customer Growth	Residential - Replacement	Area 60 - Residential - Replacement		Y	51	6,526,446	6,770,455	6,912,518	6,840,147	6,833,910	
3766	System Access	Customer Growth	Apartment Ensuite - New Construction	Area 80 - Apartment Ensuite - New Construction		Y	0	933	968	989	978	977	

Project Listing for EGD (2019-2023)

Business Case ID	Investment Category	Asset Class	Asset Program	Project Name	ICM - Eligible	Mandatory	LRROI (%)	2019 ($)	2020 ($)	2021 ($)	2022 ($)	2023 ($)	Potential for LTC
3769	System Access	Customer Growth	Commercial - New Construction	Area 80 - Commercial - New Construction		Y	148	870,247	902,784	921,727	912,077	911,245	
3770	System Access	Customer Growth	Industrial - New Construction	Area 80 - Industrial - New Construction		Y	0	871,046	903,612	922,573	912,914	912,081	
3772	System Access	Customer Growth	Residential - New Construction	Area 80 - Residential - New Construction		Y	149	5,330,790	5,530,096	5,646,133	5,587,020	5,581,926	
3773	System Access	Customer Growth	Residential - Replacement	Area 80 - Residential - Replacement		Y	41	519,754	539,186	550,500	544,736	544,239	
3783	System Access	Customer Growth	Commercial - Replacement	Area 20 - Commercial - Replacement		Y	108	537,770	557,876	569,582	563,619	563,105	
3822	System Access	Customer Growth	Commercial - Replacement	Area 80 - Commercial - Replacement		Y	31	792,328	821,952	839,198	830,412	829,655	
3523	General Plant	Fleet & Equipment	Capital Purchase Program - Equipment & Materials	2017 - 2021 485 Heavy Work Equipment		N	231	500,000	500,000	500,000	-	-	
3526	General Plant	Fleet & Equipment	Capital Purchase Program - Vehicles	2017- 2021 - 484 Light and Medium duty vehicles		N	118	5,068,514	4,902,904	5,051,154	-	-	
3546	General Plant	Fleet & Equipment	Capital Purchase Program - Tools	2017 -2021 - 486 Tools & Equipment		Y	0	800,000	800,000	800,000	-	-	
8548	General Plant	Fleet & Equipment	Capital Purchase Program - Vehicles	2022 to 2028 - 484 Light and Medium duty vehicles		N	83	-	-	-	4,652,374	4,871,000	
8549	General Plant	Fleet & Equipment	Capital Purchase Program - Tools	2022 to 2028 - 486 Tools & Equipment		Y	0	-	-	-	1,000,000	1,000,000	
8555	General Plant	Fleet & Equipment	Capital Purchase Program - Equipment & Materials	2022 to 2028 - 485 Heavy Work Equipment		N	125	-	-	-	500,000	453,801	
9554	General Plant	Fleet & Equipment	Capital Purchase Program - Vehicles	NG conversion kits for new fleet vehicles		Y	0	399,514	407,504	415,654	423,967	432,446	
1210	System Renewal	Pipe	Main Replacement	2019 Steel Mains Replacement Program		Y	1	18,843,521	-	-	-	-	
1213	System Service	Pipe	System Reinforcement - Pipe	York Region Reinforcement		Y		2,522,000	70,000	-	-	280,000	
1224	System Service	Pipe	System Reinforcement - Pipe	Bayview/Truman Reinforce.		Y	0	40,000	-	-	-	-	
1418	System Renewal	Pipe	Service Relay	2019 AMP Fitting Replacement Program		Y	56	4,406,944	-	-	-	-	
2458	System Service	Pipe	System Reinforcement - Pipe	Peterborough Reinforcement		Y	125	50,000	2,071,657	-	-	-	Y
2522	System Service	Pipe	System Reinforcement - Pipe	Rodinea Road		Y	0	921,000	-	-	-	-	
2564	System Service	Pipe	System Reinforcement - Pipe	Sideline 16 Pressure Elevation		Y	0	50,000	-	-	-	-	
6423	System Renewal	Pipe	Main Replacement	NPS 30 Don River Replacement	Y	Y	24	24,900,530	800,000	-	-	-	Y
7706	System Service	Pipe	System Reinforcement - Pipe	Bathurst Reinforcement		Y	78	8,810,839	650,000	-	-	-	Y
7709	System Service	Pipe	System Reinforcement - Pipe	Bisset Ave Reinforcement		Y	23	-	-	-	-	641,155	
7710	System Service	Pipe	System Reinforcement - Pipe	McCowan Ave HP Reinforcemen		Y	190	-	30,000	533,522	60,000	-	
7714	System Service	Pipe	System Reinforcement - Pipe	NW 2103 - Hwy 10, Orangeville Reinforcement		Y	89	-	-	-	1,859,632	-	
7715	System Service	Pipe	System Reinforcement - Pipe	Heritage and Embleton - Phase 2 reinforcement		Y	187	1,790,660	-	-	-	-	
7718	System Service	Pipe	System Reinforcement - Pipe	North Bradford Reinforcement		Y	151	644,749	-	-	-	-	
7721	System Service	Pipe	System Reinforcement - Pipe	Network 3750 - 2nd Concession Road Reinforcement		Y	133	-	-	-	214,879	-	
7724	System Service	Pipe	System Reinforcement - Pipe	Oro-Medonte IP Network Reinforcement		Y	102	-	742,847	-	-	-	
7727	System Service	Pipe	System Reinforcement - Pipe	Welland IP NW8925 Reinforcement		Y	10	1,669,305	832,152	-	-	-	
7728	System Service	Pipe	System Reinforcement - Pipe	Welland IP NW8926 Reinforcement		Y	17	-	-	-	669,036	-	
7729	System Service	Pipe	System Reinforcement - Pipe	Port Colborne IP NW8521 Reinforcement		Y	60	-	1,447,683	-	-	-	
7732	System Service	Pipe	System Reinforcement - Pipe	AJAX Reinforcement		Y	103	-	160,000	3,052,025	-	-	Y
7740	System Service	Pipe	System Reinforcement - Pipe	Kemptville Reinforcement		Y	15	-	-	-	186,000	4,839,454	Y
7742	System Service	Pipe	System Reinforcement - Pipe	Rockland IP Reinforcement		Y	98	-	692,747	-	-	-	
7743	System Service	Pipe	System Reinforcement - Pipe	L'Original Reinforcement		Y	129	172,500	3,896,608	-	-	-	Y

Project Listing for EGD (2019-2023)

Business Case ID	Investment Category	Asset Class	Asset Program	Project Name	ICM - Eligible	Mandatory	LRROI (%)	2019 ($)	2020 ($)	2021 ($)	2022 ($)	2023 ($)	Potential for LTC
8928	System Access	Pipe	Rebillable Relocation	2019 Rebillable Relocation Blanket - All Area		Y	0	1,500,000	-	-	-	-	
8930	System Access	Pipe	Rebillable Relocation	2020 Rebillable Relocation Blanket - All Area		Y	0	-	3,000,000	-	-	-	
8932	System Renewal	Pipe	Corrosion Prevention	Anode Blanket - All Areas (10 Year Plan: 2018-2027)		Y	221	1,210,943	1,228,735	1,246,841	1,265,265	1,284,014	
8948	System Renewal	Pipe	Main Replacement	Emergency Replacement Blanket - All Areas (10 year plan: 2018-2027)		Y	0	2,000,000	2,000,000	2,000,000	2,000,000	2,000,000	
8949	System Renewal	Pipe	Service Relay	Relay Blanket - All Areas (10 year plan: 2018-2027)		Y	28	17,722,914	20,295,803	21,195,208	22,174,994	23,183,476	
9216	System Service	Pipe	System Reinforcement - Pipe	Old ChurchRoad to Bruno Ridge Dr. Reinforcement		Y	155	-	-	-	-	496,862	
9521	System Service	Pipe	System Reinforcement - Pipe	Sideline 16 and Brock Pressure Control Station (part of pipe Reinforcement)		Y	0	1,107,845	-	-	-	-	
9551	System Service	Pipe	Integrity Initiatives - Pipe	Fiber Optics on Vital and Critical Mains		N	6	-	1,358,000	1,092,500	1,381,500	583,000	
10087	System Access	Pipe	Rebillable Relocation	NPS 20 Don River Relocation	Y	Y	121	13,016,712	22,006,030	850,000			Y
10089	System Renewal	Pipe	Main Replacement	NPS 12 St. Laurent Ottawa North Main Replacement (2021+)	Y	N	1	-	-	9,239,682	40,641,901	2,250,000	Y
10223	System Renewal	Pipe	Service Relay	2020 AMP Fitting Replacement Program		Y	61	-	4,483,144	-	-	-	
10224	System Renewal	Pipe	Service Relay	2021 AMP Fitting Replacement Program		Y	66	-	-	6,841,115	-	-	
10261	System Renewal	Pipe	Service Relay	2022 AMP Fitting Replacement Program		Y	71	-	-	-	9,279,287	-	
10262	System Renewal	Pipe	Service Relay	2023 AMP Fitting Replacement Program		Y	76	-	-	-	-	10,839,819	
10281	System Access	Pipe	Rebillable Relocation	2021 Rebillable Relocation Blanket - All Area		Y	0	-	-	7,700,000	-	-	
10282	System Access	Pipe	Rebillable Relocation	2022 Rebillable Relocation Blanket - All Area		Y	0	-	-	-	7,700,000	-	
10283	System Access	Pipe	Rebillable Relocation	2023 Rebillable Relocation Blanket - All Area		Y	0	-	-	-	-	7,700,000	
10321	System Renewal	Pipe	Main Replacement	2020 Steel Mains Replacement Program		Y	1	-	21,598,770	-	-	-	
10322	System Renewal	Pipe	Main Replacement	2021 Steel Mains Replacement Program		Y	1	-	-	24,116,965	-	-	
10323	System Renewal	Pipe	Main Replacement	2022 Steel Mains Replacement Program		Y	1	-	-	-	26,928,763	-	
10324	System Renewal	Pipe	Main Replacement	2023 Steel Mains Replacement Program		Y	1	-	-	-	-	30,068,397	
10342	System Renewal	Pipe	Main Replacement	2019 Vintage PE Main Replacement Program		Y	2	1,889,314	-	-	-	-	
10343	System Renewal	Pipe	Main Replacement	2020 Vintage PE Main Replacement Program		Y	2	-	2,275,540	-	-	-	
10345	System Renewal	Pipe	Main Replacement	2021 Vintage PE Main Replacement Program		Y	2	-	-	2,745,970	-	-	
10346	System Renewal	Pipe	Main Replacement	2022 Vintage PE Main Replacement Program		Y	2	-	-	-	3,319,220	-	
10347	System Renewal	Pipe	Main Replacement	2023 Vintage PE Main Replacement Program		Y	2	-	-	-	-	4,018,034	
11443	System Renewal	Pipe	Main Replacement	NPS 12 Martin Grove Rd Main Replacement Ph 2	Y	N	3	-	-	-	-	400,000	
16507	System Service	Pipe	System Reinforcement - Pipe	Limoges Reinforcement		Y	82	-	-	1,386,603	-	-	
16744	System Service	Pipe	System Reinforcement - Pipe	Amaranth System Reinforcement		Y	39	-	-	100,000	100,000	-	
16748	System Service	Pipe	System Reinforcement - Pipe	Erin IP System Reinforcement		Y	69	1,454,120	-	-	-	1,711,158	
16749	System Service	Pipe	System Reinforcement - Pipe	Mearns & Flaxman Upsize / Reinforcement		Y	178	98,696	-	-	-	-	
16751	System Service	Pipe	System Reinforcement - Pipe	Thornton XHP reinforcement		Y	158	-	-	-	1,834,811	3,633,007	Y
16752	System Service	Pipe	System Reinforcement - Pipe	Bridle Path Reinforcement		Y	6	-	1,663,977	-	-	-	
17227	System Service	Pipe	System Reinforcement - Pipe	Caledon IP System Reinforcement		Y	124	-	100,000	121,136	-	-	
17243	System Service	Pipe	System Reinforcement - Pipe	NW 2225 terra cotta Reinforcement		Y	18	-	809,144	-	-	-	
17364	System Renewal	Pipe	Integrity Retrofit - Pipe	NPS 8 Blackburn Extension		Y	0	3,855,000	-	-	-	-	

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Business Case ID	Investment Category	Asset Class	Asset Program	Project Name	ICM - Eligible	Mandatory	LRROI (%)	2019 ($)	2020 ($)	2021 ($)	2022 ($)	2023 ($)	Potential for LTC
19123	System Service	Pipe	System Reinforcement - Pipe	York Region Reinforcement - Civic Centre to Baseline 2.1 Km		Y	0	1,000,100	-	-	-	-	
19345	System Renewal	Pipe	Non-Rebillable Relocation	2019 Non-Rebillable Relocation Blanket - All Area		Y	0	1,500,000	-	-	-	-	
19346	System Renewal	Pipe	Non-Rebillable Relocation	2020 Non-Rebillable Relocation Blanket - All Area		Y	0	-	2,000,000	-	-	-	
19347	System Renewal	Pipe	Non-Rebillable Relocation	2021 Non-Rebillable Relocation Blanket - All Area		Y	0	-	-	2,000,000	-	-	
19349	System Renewal	Pipe	Non-Rebillable Relocation	2022 Non-Rebillable Relocation Blanket - All Area		Y	0	-	-	-	2,000,000	-	
19352	System Renewal	Pipe	Non-Rebillable Relocation	2023 Non-Rebillable Relocation Blanket - All Area		Y	0	-	-	-	-	2,000,000	
19503	System Renewal	Pipe	Main Replacement	NPS 20 Lake Shore KOL Replacement (Parliament to Bathurst) Planning & Design		N	0	250,000	1,650,000	-	-	-	
19505	System Renewal	Pipe	Main Replacement	St Laurent NPS 12 Planning Dollars (2019/2020)		N	0	250,000	150,000	-	-	-	
1796	General Plant	REWS	Furniture / Structures & Improvements	Brampton Operations Centre Alterations		Y	123	100,000	3,100,000	-	-	-	
3634	General Plant	REWS	Furniture / Structures & Improvements	VPC-1		N	109	-	4,200,000	-	-	-	
3635	General Plant	REWS	Furniture / Structures & Improvements	VPC-B		N	91	-	-	2,000,000	-	-	
3636	General Plant	REWS	Furniture / Structures & Improvements	VPC-2		N	113	1,180,000	-	-	-	-	
3637	General Plant	REWS	Furniture / Structures & Improvements	VPC-Link and stairwells		N	89	-	750,000	750,000	-	-	
3638	General Plant	REWS	Furniture / Structures & Improvements	TOC EMEC Expansion		N	102	50,000	50,000	3,500,000	-	-	
3639	General Plant	REWS	Furniture / Structures & Improvements	Kennedy Road Expansion	Y	N	90	-	-	-	9,200,000	8,000,000	
3640	General Plant	REWS	Furniture / Structures & Improvements	Station B New Building		N	83	-	5,000,000	1,500,000	-	-	
3641	General Plant	REWS	Furniture / Structures & Improvements	EGD targeted GHG & Energy reductions		N	237	350,000	350,000	350,000	-	-	
3642	General Plant	REWS	Furniture / Structures & Improvements	Eastern Region Consolidated facility	Y	N	58	-	25,000	-	-	-	
3644	General Plant	REWS	Furniture / Structures & Improvements	2017,2019-21 Furniture & Ergonomic blanket		Y	193	203,460	206,979	210,560	-	-	
3675	General Plant	REWS	Furniture / Structures & Improvements	Cabling 2017-2021		Y	112	101,730	103,489	105,280	-	-	
4333	General Plant	REWS	Furniture / Structures & Improvements	Direct Capital Overheads		Y	72	530,000	530,000	530,000	250,000	250,000	
6081	General Plant	REWS	Furniture / Structures & Improvements	2019 Blanket for Building Systems		Y	106	1,831,140	-	-	-	-	
6082	General Plant	REWS	Furniture / Structures & Improvements	2020 Blanket for Building Systems		Y	106	-	1,862,819	-	-	-	
6083	General Plant	REWS	Furniture / Structures & Improvements	2021 Blanket for Building Systems		Y	106	-	-	1,895,045	-	-	
6087	General Plant	REWS	Furniture / Structures & Improvements	New Mechanical Services Building		N	135	-	-	4,500,000	4,500,000	-	
6104	General Plant	REWS	Furniture / Structures & Improvements	Barrie Operations Centre Obsolescence		N	85	-	1,000,000	6,000,000	-	-	
6143	General Plant	REWS	Furniture / Structures & Improvements	Peterborough Operations Centre Obsolescence		N	70	-	-	1,000,000	3,450,000	-	
8677	General Plant	REWS	Furniture / Structures & Improvements	Arnprior Operations Centre Obsolescence		N	70	-	-	500,000	1,600,000	-	
8701	General Plant	REWS	Furniture / Structures & Improvements	Kelfield Operations Centre Obsolescence.		N	91	-	1,000,000	4,700,000	1,100,000	-	
8703	General Plant	REWS	Furniture / Structures & Improvements	Brockville Operations Centre Obsolescence		N	74	-	1,500,000	3,350,000	-	-	
8765	General Plant	REWS	Furniture / Structures & Improvements	2022 Blanket for Building Systems		Y	106	-	-	-	1,927,830	-	
8766	General Plant	REWS	Furniture / Structures & Improvements	2023 Blanket for Building Systems		Y	106	-	-	-	-	1,961,181	
8826	General Plant	REWS	Furniture / Structures & Improvements	Cabling 2022-2026		Y	112	-	-	-	107,101	108,954	
8828	General Plant	REWS	Furniture / Structures & Improvements	2022-2026 Furniture & Ergonomic blanket		Y	193	-	-	-	214,203	217,909	
15603	General Plant	REWS	Furniture / Structures & Improvements	VPC Emergency Life Safety Systems Backup Power		Y	0	1,450,000	-	-	-	-	
1011	System Renewal	Stations	Gate & Feeder Station	SCHOMBERG GATE		Y	25	-	-	-	1,278,897	698,558	

Project Listing for EGD (2019-2023)

Business Case ID	Investment Category	Asset Class	Asset Program	Project Name	ICM - Eligible	Mandatory	LRROI (%)	2019 ($)	2020 ($)	2021 ($)	2022 ($)	2023 ($)	Potential for LTC
1012	System Renewal	Stations	Gate & Feeder Station	LEEDS GATE		N	69	-	200,000	573,229	-	-	
1013	System Renewal	Stations	Gate & Feeder Station	MARKHAM GATE		Y	10	-	-	-	-	1,480,274	
1029	System Renewal	Stations	Gate & Feeder Station	DEEP RIVER GATE		Y	27	1,767,000	-	-	-	-	
1031	System Renewal	Stations	Gate & Feeder Station	ORO-MEDONTE GATE		Y	4	1,064,449	630,218	-	-	-	
1239	System Renewal	Stations	Gate & Feeder Station	MARTIN GROVE FEEDER		Y	16	-	-	-	-	747,157	
1240	System Renewal	Stations	Gate & Feeder Station	WEST MALL FEEDER		Y	48	1,400,000	-	-	-	-	
1261	System Renewal	Stations	Inside Regulator Program	ERR Program		Y	0	500,000	500,000	500,000	500,000	500,000	
1700	System Renewal	Stations	Gate & Feeder Station	BLACKHORSE GATE		Y	244	1,200,000	2,433,653	-	-	-	
2719	System Renewal	Stations	Gate & Feeder Station	YONGE AND STEELES FEEDER		N	58	-	-	215,608	369,715	-	
3455	System Renewal	Stations	Station Rebuild	Harmer District Station		Y	0	-	1,688,739	-	-	-	
3483	System Renewal	Stations	Station Rebuild	2019 Header stations rebuilds		Y	150	924,000	-	-	-	-	
3484	System Renewal	Stations	Station Rebuild	2020 Header stations rebuilds		Y	150	-	924,000	-	-	-	
3486	System Renewal	Stations	Station Rebuild	2021 Header stations rebuilds		Y	150	-	-	924,000	-	-	
3573	System Renewal	Stations	Gate & Feeder Station	2019 M&R Compliance Project		Y	357	200,000	-	-	-	-	
3574	System Renewal	Stations	Gate & Feeder Station	2020 M&R Compliance Project		Y	357	-	200,000	-	-	-	
3575	System Renewal	Stations	Gate & Feeder Station	2021 M&R Compliance Project		Y	357	-	-	200,000	-	-	
3579	System Renewal	Stations	Station Rebuild	2019 Sales stations rebuilds		Y	130	1,100,000	-	-	-	-	
3580	System Renewal	Stations	Station Rebuild	2020 Sales stations rebuilds		Y	87	-	1,500,000	-	-	-	
3581	System Renewal	Stations	Station Rebuild	2021 Sales stations rebuilds		Y	60	-	-	2,000,000	-	-	
3584	System Renewal	Stations	Station Rebuild	2019 District Station Rebuilds Program		Y	185	6,500,000	-	-	-	-	
3585	System Renewal	Stations	Station Rebuild	2020 District Station Rebuilds Program		Y	160	-	6,500,000	-	-	-	
3586	System Renewal	Stations	Station Rebuild	2021 District Station Rebuilds Program		Y	123	-	-	7,000,000	-	-	
3605	System Renewal	Stations	Gate & Feeder Station	BAYVIEW FEEDER		N	54	-	-	338,581	853,264	-	
3609	System Renewal	Stations	Gate & Feeder Station	CONSUMERS RD		N	34	750,626	-	-	-	-	
3610	System Renewal	Stations	Gate & Feeder Station	CROWLAND STORAGE TRANSFER		Y	15	-	-	-	611,314	127,373	
3612	System Renewal	Stations	Gate & Feeder Station	LISGAR GATE		Y	30	-	-	-	2,593,599	2,346,579	
3619	System Renewal	Stations	Gate & Feeder Station	MITCH OWENS GATE ABANDONMENT		Y	0	58,892	-	-	-	-	
3621	System Renewal	Stations	Station Rebuild	ROCKCLIFFE CONTROL DISTRICT		N	3	-	-	-	500,000	-	
3624	System Renewal	Stations	Gate & Feeder Station	VICTORIA SQUARE GATE		N	4	-	500,000	-	-	-	
3631	System Renewal	Stations	Gate & Feeder Station	2019 Telemetry		Y	59	1,400,000	-	-	-	-	
3632	System Renewal	Stations	Gate & Feeder Station	2020 Telemetry		Y	60	-	1,400,000	-	-	-	
3633	System Renewal	Stations	Gate & Feeder Station	2021 Telemetry		Y	57	-	-	1,400,000	-	-	
7061	System Renewal	Stations	Gate & Feeder Station	BRAMPTON GATE		Y	23	-	300,000	1,194,515	-	-	
7747	System Renewal	Stations	Gate & Feeder Station	BEAMSVILLE GATE		N	12	-	128,712	-	-	-	
7748	System Renewal	Stations	Gate & Feeder Station	BETHEL GATE		Y	31	-	-	-	974,903	675,571	
7750	System Renewal	Stations	Gate & Feeder Station	HALEY GATE		Y	0	-	-	-	255,573	-	

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7752	System Renewal	Stations	Gate & Feeder Station	NIAGARA GATE		N	28	-	-	-	437,170	289,703	
7755	System Renewal	Stations	Gate & Feeder Station	PETAWAWA GATE		N	0	-	-	-	287,360	-	
7758	System Renewal	Stations	Gate & Feeder Station	THORNTON GATE		N	43	-	-	871,862	321,539	-	
7761	System Renewal	Stations	Gate & Feeder Station	ALBION ROAD FEEDER		N	102	-	224,799	241,095	-	-	
7766	System Renewal	Stations	Gate & Feeder Station	DURHAM 23 FEEDER		N	138	-	-	-	-	188,789	
7768	System Renewal	Stations	Gate & Feeder Station	JONESVILLE FEEDER		N	14	263,000	1,304,462	-	-	-	
7769	System Renewal	Stations	Gate & Feeder Station	KEELE AND STEELES/CNR FEEDER		N	52	-	-	558,121	503,607	-	
7772	System Renewal	Stations	Gate & Feeder Station	MALTON FEEDER		N	75	-	266,965	558,782	-	-	
7775	System Renewal	Stations	Gate & Feeder Station	SIGNET & FINCH FEEDER		N	62	-	-	203,768	276,082	-	
7776	System Renewal	Stations	Gate & Feeder Station	STATION "B" FEEDER		Y	70	-	203,768	276,082	-	-	
7777	System Renewal	Stations	Gate & Feeder Station	WINSTON CHURCHILL AND STEELES FEEDER		N	51	-	-	215,608	369,715	-	
7778	System Renewal	Stations	Gate & Feeder Station	WOODBINE & CNR FEEDER		N	54	-	-	215,608	369,715	-	
7780	System Renewal	Stations	Gate & Feeder Station	CREDITVIEW AND 403 / MCCONELL DISTRICT		Y	69	-	203,768	276,082	-	-	
8144	System Service	Stations	Integrity Initiatives - Stations	Integrity Stations Retrofit Program > 30% SMYS		Y	11	2,573,483	1,850,374	1,197,377	1,500,000	1,400,000	
8567	System Renewal	Stations	Gate & Feeder Station	STJOHN SIDEROAD FEEDER		Y	8	1,000,000	4,659,370	-	-	-	
8935	System Renewal	Stations	Station Rebuild	2022 District Station Rebuilds Program		Y	109	-	-	-	7,500,000	-	
8936	System Renewal	Stations	Station Rebuild	2022 Header stations rebuilds		Y	150	-	-	-	924,000	-	
8937	System Renewal	Stations	Station Rebuild	2022 Sales stations rebuilds		Y	68	-	-	-	2,035,000	-	
8939	System Renewal	Stations	Gate & Feeder Station	2022 Telemetry		Y	57	-	-	-	1,400,000	-	
8940	System Renewal	Stations	Gate & Feeder Station	2022 M&R Compliance Project		Y	357	-	-	-	200,000	-	
9464	System Renewal	Stations	Gate & Feeder Station	2023 M&R Compliance Project		Y	357	-	-	-	-	200,000	
9741	System Renewal	Stations	Gate & Feeder Station	PARKWAY GATE		Y	45	-	-	-	1,966,132	2,097,662	
9842	System Renewal	Stations	Station Rebuild	2023 Header stations rebuilds		Y	150	-	-	-	-	924,000	
9844	System Renewal	Stations	Station Rebuild	2023 Sales stations rebuilds		Y	58	-	-	-	-	2,070,613	
9846	System Renewal	Stations	Gate & Feeder Station	2023 Telemetry		Y	56	-	-	-	-	1,400,000	
10241	System Renewal	Stations	Station Rebuild	2023 District Station Rebuilds Program		Y	55	-	-	-	-	7,500,000	
10295	System Renewal	Stations	Station Rebuild	Station Emergency Replacement Blanket - All Areas		Y	148	200,000	200,000	200,000	200,000	200,000	
13384	System Renewal	Stations	Gate & Feeder Station	Campbell St District Stn relocate		Y	112	-	1,930,820	2,002,269	-	-	
1001	System Renewal	Storage	Field Lines	LSEC:Crude Carryover-Reduce		N	142	-	-	-	508,200	-	
1040	System Renewal	Storage	Compressor Equipment	SCOR:Light Poles-Replace		Y	0	82,345	-	-	-	-	
1122	System Renewal	Storage	Wells and Well Equipment	PCOR:TC8 A1 Obs Well-Drill		N	147	-	343,850	1,190,250	-	-	
1135	System Renewal	Storage	Compressor Equipment	SCOR:Fire Hydrant-Install		N	1823	230,000	-	-	-	-	
1811	System Renewal	Storage	Compressor Equipment	SCOR:Meter Area-Upgrade	Y	Y	310	11,000,000	18,000,000	14,600,000	-	-	
2222	System Renewal	Storage	Compressor Equipment	SCOR:60001/2 iBalance-Upgrade		Y	0	300,000	-	-	-	-	
3004	System Renewal	Storage	Compressor Equipment	SSOM:820 PLC01A/B-Replace		N	267	600,000	-	-	-	-	
3024	System Renewal	Storage	Wells and Well Equipment	PDOW:TD18-Acidize		Y	0	65,136	-	-	-	-	

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3025	System Renewal	Storage	Wells and Well Equipment	PMKC:TKC35-Acidize		Y	0	65,136	-	-	-	-	
3026	System Renewal	Storage	Wells and Well Equipment	PSKC:TKC14-Acidize		Y	0	65,136	-	-	-	-	
3027	System Renewal	Storage	Wells and Well Equipment	PSKC:TKC48-Acidize		Y	0	65,136	-	-	-	-	
3029	System Renewal	Storage	Wells and Well Equipment	PSKC:TKC47-Acidize		Y	0	65,136	-	-	-	-	
3141	System Renewal	Storage	Wells and Well Equipment	PDOW:TD26 A1 Obs Well-Execute		N	386	1,063,871	-	-	-	-	
3142	System Renewal	Storage	Wells and Well Equipment	PCOV:TCV7 A1 Obs Well-Drill		N	51	-	-	343,850	1,190,250	-	
3318	System Service	Storage	Integrity Initiatives - Storage	LSEC:Laterals-ILI Retrofit		Y	6	140,625	-	-	-	-	
3320	System Service	Storage	Integrity Initiatives - Storage	LDOW:Laterals-ILI Retrofit		Y	12	-	-	-	200,000	-	
3327	System Service	Storage	Integrity Initiatives - Storage	LSOM:NPS16-ILI Retrofit		Y	9	-	-	-	144,900	-	
3335	System Service	Storage	Integrity Initiatives - Storage	LCOR:NPS16G-ILI Retrofit		Y	105	-	161,300	-	-	-	
3336	System Service	Storage	Integrity Initiatives - Storage	LSEC:NPS20G-ILI Retrofit		Y	203	336,450	-	-	-	-	
3340	System Service	Storage	Integrity Initiatives - Storage	LWLK:NPS16P-ILI Retrofit		Y	2	-	144,900	-	-	-	
3352	System Renewal	Storage	Wells and Well Equipment	PBCK:TBC3 ESD-Install		Y	0	50,000	-	-	-	-	
3354	System Renewal	Storage	Field Lines	LBCK:TBC3 W/L-Replace		Y	0	75,000	-	-	-	-	
3380	System Renewal	Storage	Compressor Equipment	SCOR:61004 Top End-O/H		N	733	-	-	250,000	-	-	
3386	System Renewal	Storage	Compressor Equipment	SCOR:61008 Top End-O/H		N	809	-	-	-	250,000	-	
3389	System Renewal	Storage	Compressor Equipment	SCOR:61007 Bottom End-O/H		N	533	-	425,000	-	-	-	
3390	System Renewal	Storage	Compressor Equipment	SCOR:61008 Bottom End-O/H		N	697	-	-	-	300,000	-	
3423	System Renewal	Storage	Compressor Equipment	SCOR:600 Disch PSV-Upgrade		Y	0	165,000	165,000	165,000	-	-	
3449	System Renewal	Storage	Compressor Equipment	SCOR:60006 iBalance-Upgrade		N	246	-	396,900	163,800	-	-	
3450	System Renewal	Storage	Compressor Equipment	SCOR:60007 iBalance-Upgrade		N	279	-	-	-	-	396,900	
3451	System Renewal	Storage	Compressor Equipment	SCOR:60005 iBalance-Upgrade		N	312	-	396,900	163,800	-	-	
3452	System Renewal	Storage	Compressor Equipment	SCOR:60010 iBalance-Upgrade		N	77	-	-	-	-	396,900	
3453	System Renewal	Storage	Compressor Equipment	SCOR:60008 iBalance-Upgrade		N	347	-	-	396,900	163,800	-	
3456	System Renewal	Storage	Compressor Equipment	SCOR:60009 iBalance-Upgrade		N	125	-	-	396,900	163,800	-	
3459	System Renewal	Storage	Compressor Equipment	SCOR:60008-Fdn Blk-Replace		N	340	-	2,050,000	-	-	-	
3460	System Renewal	Storage	Compressor Equipment	SCOR:60007-Fdn Blk-Replace		N	231	-	-	2,050,000	-	-	
3558	System Renewal	Storage	Compressor Equipment	SCOR:Unit Pre-Heat-Convrt		N	38	-	-	-	275,000	-	
3559	System Renewal	Storage	Compressor Equipment	SM:Telemetry-Upgrade		Y	0	1,240,625	-	-	-	-	
3826	System Renewal	Storage	Field Lines	LLAD:NPS16P-AC Mitigation		N	801	34,500	172,500	-	-	-	
5541	System Renewal	Storage	Wells and Well Equipment	PLAD:TL8 A1 Obs Well-Drill		N	73	-	343,850	1,190,250	-	-	
5624	System Renewal	Storage	Compressor Equipment	SCOR:60004-Fdn Blk-Replace		N	432	-	-	-	2,050,000	-	
5765	System Service	Storage	Integrity Initiatives - Storage	LCOV:NPS16G-ILI Retrofit		Y	199	-	-	-	144,900	-	
5767	System Service	Storage	Integrity Initiatives - Storage	LCOV:NPS16P-ILI Retrofit		Y	36	-	-	-	144,900	-	
5768	System Service	Storage	Integrity Initiatives - Storage	LLAD:NPS16G-ILI Retrofit		Y	9	-	-	144,900	-	-	
5769	System Service	Storage	Integrity Initiatives - Storage	LWLK:NPS16G-ILI Retrofit		Y	33	-	144,900	144,900	-	-	

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5770	System Service	Storage	Integrity Initiatives - Storage	LSKC:NPS20L-ILI Retrofit		Y	4544	-	144,900	-	-	-	
5772	System Service	Storage	Integrity Initiatives - Storage	LDOW:NPS20x16G-ILI Retrofit		Y	303	-	-	-	-	483,000	
5861	System Service	Storage	Integrity Initiatives - Storage	LWLK:Laterals-ILI Retrofit		Y	0	-	75,000	-	-	-	
5882	System Service	Storage	Integrity Initiatives - Storage	LMKC:Laterals-ILI Retrofit		Y	5	-	-	150,000	-	-	
6361	System Renewal	Storage	Field Lines	LDOW:Leaking Wells-Replace		N	74	1,205,800	-	-	-	-	
6362	System Renewal	Storage	Field Lines	LSKC:TKC67H New HWell		N	74	110,400	517,500	-	-	-	
6363	System Renewal	Storage	Wells and Well Equipment	PSKC:TKC67H New HWell		N	68	300,000	2,395,000	-	-	-	
8622	System Renewal	Storage	Compressor Equipment	SCHT:Inverter-Replace		Y	0	65,000	-	-	-	-	
8624	System Renewal	Storage	Compressor Equipment	SCHT:Control Room-Expand		N	49	-	-	-	-	780,000	
8625	System Renewal	Storage	Compressor Equipment	SCHT:Air Comp,Dryer-Replace		N	104	-	-	-	-	260,000	
8628	System Renewal	Storage	Compressor Equipment	SCHT:Dehy Automatn-Upgrade		N	3	-	-	-	-	325,000	
8629	System Renewal	Storage	Compressor Equipment	SSOM:Limitorque MX-Replace		N	113	210,000	210,000	210,000	210,000	420,000	
8630	System Renewal	Storage	Measurement and Regulating Equipment - Storage	SSOM:UT Meters-Replace		N	91	-	-	-	520,000	-	
8632	System Renewal	Storage	Compressor Equipment	SSOM:GAC Fan-Upgrade		N	4	-	-	-	391,642	-	
8640	System Renewal	Storage	Compressor Equipment	SSOM:HMI Hi Perf Grafx-Install		N	169	-	-	-	-	455,000	
8641	System Renewal	Storage	Compressor Equipment	SSOM:LAN Room-Install		N	24	-	-	-	-	1,040,000	
8644	System Renewal	Storage	Compressor Equipment	SSOM:Video Wall-Install		N	475	-	195,000	-	-	-	
8651	System Renewal	Storage	Compressor Equipment	SM:Industr'l Wireless-Install		N	291	97,500	97,500	-	-	-	
8652	System Renewal	Storage	Measurement and Regulating Equipment - Storage	LM:MS Wireless Mesh-Install		N	32	-	-	-	195,000	195,000	
8653	System Renewal	Storage	Compressor Equipment	SCOR:810001 IDC-Replace		Y	42	-	-	650,000	-	-	
8654	System Renewal	Storage	Compressor Equipment	SCOR:HMI PCs-Replace		Y	0	65,000	-	-	-	-	
8661	System Renewal	Storage	Compressor Equipment	SSOM:622xx Vssl Closure-Upgrade		N	26	-	-	-	-	276,761	
8670	System Renewal	Storage	Compressor Equipment	SSOM:Methane Vent-Reduce		Y	0	370,984	738,802	-	-	-	
8671	System Renewal	Storage	Compressor Equipment	SCHT:Methane Vent-Reduce		Y	0	370,984	738,802	-	-	-	
8673	System Renewal	Storage	Compressor Equipment	MM:Leak Detection-Develop		Y	0	98,000	-	-	-	-	
8675	System Renewal	Storage	Wells and Well Equipment	PDOW:TD27 Obs Well-Install		Y	391	1,190,250	-	-	-	-	
8686	System Renewal	Storage	Wells and Well Equipment	PM:ESD Methanol Injectn-Install		Y	0	90,000	-	-	-	-	
8687	System Renewal	Storage	Compressor Equipment	SSOM:61001-Engine Minor		N	731	-	-	-	130,000	-	
8688	System Renewal	Storage	Compressor Equipment	SSOM:61002-Engine minor		N	731	-	-	-	130,000	-	
8841	System Renewal	Storage	Compressor Equipment	SCOR:HMI Hi Perf Grafx-Install		N	169	-	-	-	455,000	455,000	
8844	System Renewal	Storage	Compressor Equipment	SCOR:HMI PCs-Replace		Y	0	-	-	-	65,000	-	
8851	System Renewal	Storage	Compressor Equipment	SSOM:UPS-replace		N	73	-	-	-	130,000	-	
8853	System Renewal	Storage	Measurement and Regulating Equipment - Storage	LM:MS UPS-Replace		Y	0	14,300	-	-	-	-	
8854	System Renewal	Storage	Compressor Equipment	SSOM:Platforms-Install		Y	0	65,000	-	-	-	-	
8857	System Renewal	Storage	Wells and Well Equipment	PM:Wells-Acidize		N	397	-	390,816	-	-	-	
8858	System Renewal	Storage	Wells and Well Equipment	PM:Wells-Acidize		N	397	-	-	-	390,816	-	

Project Listing for EGD (2019-2023)

Business Case ID	Investment Category	Asset Class	Asset Program	Project Name	ICM - Eligible	Mandatory	LRROI (%)	2019 ($)	2020 ($)	2021 ($)	2022 ($)	2023 ($)	Potential for LTC
8891	System Service	Storage	Integrity Initiatives - Storage	LDOW:NPS24P-ILI Retrofit		Y	0	-	-	-	-	144,900	
8943	System Service	Storage	Records Integrity - Storage	MM:Carryover Dwgs-Complet		Y	0	50,000	-	-	-	-	
8957	System Service	Storage	Records Integrity - Storage	MM:Carryover Dwgs-Complet		Y	0	-	50,000	-	-	-	
8958	System Service	Storage	Records Integrity - Storage	MM:Carryover Dwgs-Complet		Y	0	-	-	50,000	-	-	
8959	System Service	Storage	Records Integrity - Storage	MM:Carryover Dwgs-Complet		Y	0	-	-	-	50,000	-	
8960	System Service	Storage	Records Integrity - Storage	MM:Carryover Dwgs-Complet		Y	0	-	-	-	-	50,000	
8967	System Renewal	Storage	Field Lines	LM:Well Loops-Adjust		Y	0	71,045	-	-	-	-	
8968	System Renewal	Storage	Field Lines	LM:Well Loops-Adjust		Y	0	-	71,045	-	-	-	
8969	System Renewal	Storage	Field Lines	LM:Well Loops-Adjust		Y	0	-	-	71,045	-	-	
8970	System Renewal	Storage	Field Lines	LM:Well Loops-Adjust		Y	0	-	-	-	71,045	-	
8971	System Renewal	Storage	Field Lines	LM:Well Loops-Adjust		Y	0	-	-	-	-	71,045	
8981	System Renewal	Storage	Field Lines	LM:Leaking Valves-Replace		Y	109	462,000	-	-	-	-	
8985	System Renewal	Storage	Field Lines	LM:Leaking Valves-Replace		Y	109	-	462,000	-	-	-	
8987	System Renewal	Storage	Field Lines	LM:Leaking Valves-Replace		Y	109	-	-	307,000	-	-	
8990	System Renewal	Storage	Field Lines	LM:Leaking Valves-Replace		Y	109	-	-	-	307,000	-	
8991	System Renewal	Storage	Field Lines	LM:Leaking Valves-Replace		Y	109	-	-	-	-	307,000	
9016	System Renewal	Storage	Wells and Well Equipment	PM:Well Casing-Replace		Y	153	400,000	-	-	-	-	
9017	System Renewal	Storage	Wells and Well Equipment	PM:Roads&Laneways-Improve		Y	0	66,000	-	-	-	-	
9018	System Service	Storage	Integrity Initiatives - Storage	SM:FIMP Recommend'ns-Implement		Y	0	50,000	-	-	-	-	
9019	System Renewal	Storage	Wells and Well Equipment	PM:Roads&Laneways-Improve		Y	0	-	66,000	-	-	-	
9020	System Service	Storage	Integrity Initiatives - Storage	SM:FIMP Recommend'ns-Implement		Y	0	-	50,000	-	-	-	
9021	System Service	Storage	Integrity Initiatives - Storage	SM:FIMP Recommend'ns-Implement		Y	0	-	-	50,000	-	-	
9022	System Service	Storage	Integrity Initiatives - Storage	SM:FIMP Recommend'ns-Implement		Y	0	-	-	-	50,000	-	
9023	System Service	Storage	Integrity Initiatives - Storage	SM:FIMP Recommend'ns-Implement		Y	0	-	-	-	-	50,000	
9041	System Renewal	Storage	Compressor Equipment	SM:SCADA-Annual Upgrade		Y	0	55,000	-	-	-	-	
9042	System Renewal	Storage	Compressor Equipment	SM:SCADA-Annual Upgrade		Y	0	-	55,000	-	-	-	
9061	System Renewal	Storage	Compressor Equipment	SM:SCADA-Annual Upgrade		Y	0	-	-	55,000	-	-	
9062	System Renewal	Storage	Compressor Equipment	SM:SCADA-Annual Upgrade		Y	0	-	-	-	55,000	-	
9063	System Renewal	Storage	Compressor Equipment	SM:SCADA-Annual Upgrade		Y	0	-	-	-	-	55,000	
9181	System Renewal	Storage	Measurement and Regulating Equipment - Storage	LM:MS UPS-Replace		Y	0	-	14,300	-	-	-	
9182	System Renewal	Storage	Measurement and Regulating Equipment - Storage	LM:MS UPS-Replace		Y	0	-	-	14,300	-	-	
9183	System Renewal	Storage	Measurement and Regulating Equipment - Storage	LM:MS UPS-Replace		Y	0	-	-	-	14,300	-	
9184	System Renewal	Storage	Measurement and Regulating Equipment - Storage	LM:MS UPS-Replace		Y	0	-	-	-	-	14,300	
9542	System Renewal	Storage	Wells and Well Equipment	PM:Well Casing-Replace		Y	153	-	400,000	-	-	-	
9543	System Renewal	Storage	Wells and Well Equipment	PM:Well Casing-Replace		Y	153	-	-	400,000	-	-	
9544	System Renewal	Storage	Wells and Well Equipment	PM:Well Casing-Replace		Y	153	-	-	-	400,000	-	

Project Listing for EGD (2019-2023)

Business Case ID	Investment Category	Asset Class	Asset Program	Project Name	ICM - Eligible	Mandatory	LRROI (%)	2019 ($)	2020 ($)	2021 ($)	2022 ($)	2023 ($)	Potential for LTC
9545	System Renewal	Storage	Wells and Well Equipment	PM:Well Casing-Replace		Y	153	-	-	-	-	400,000	
9581	System Renewal	Storage	Wells and Well Equipment	PM:Roads&Laneways-Improve		Y	0	-	-	66,000	-	-	
9582	System Renewal	Storage	Wells and Well Equipment	PM:Roads&Laneways-Improve		Y	0	-	-	-	66,000	-	
9583	System Renewal	Storage	Wells and Well Equipment	PM:Roads&Laneways-Improve		Y	0	-	-	-	-	66,000	
10029	System Renewal	Storage	Compressor Equipment	SCHT:UPS-replace		Y	0	-	-	26,000	-	-	
11703	System Renewal	Storage	Compressor Equipment	SCOR:Storage-Maintenance		N	474	1,240,154	1,017,800	1,134,800	518,000	366,200	
12627	System Renewal	Storage	Wells and Well Equipment	PDOW:TD28H New HWell		Y	74	1,799,983	-	-	-	-	
12628	System Renewal	Storage	Wells and Well Equipment	PDOW:TD29H New HWell		Y	74	1,875,902	-	-	-	-	
12863	System Renewal	Storage	Compressor Equipment	SCOR:Unit Pre-Heat-Convrt		N	31	-	-	-	-	275,000	
12913	System Renewal	Storage	Compressor Equipment	SCOR:62008 Comp-Major O/H		N	653	-	-	325,000	-	-	
12916	System Renewal	Storage	Compressor Equipment	SCOR:62011 Comp-Major O/H		N	563	-	-	325,000	-	-	
12919	System Renewal	Storage	Compressor Equipment	SCOR:61004 Bottom End-O/H		N	509	-	-	400,000	-	-	
12922	System Renewal	Storage	Compressor Equipment	SCOR:620xx Cyl Liner-Replace		N	421	-	-	-	263,040	-	
12924	System Renewal	Storage	Compressor Equipment	SCOR:64105 JWC-Replace		N	246	-	227,267	306,544	-	-	
12925	System Renewal	Storage	Compressor Equipment	SCOR:64106 JWC-Replace		N	225	-	-	227,267	306,544	-	
12926	System Renewal	Storage	Compressor Equipment	SCOR:64107 JWC-Replace		N	210	-	-	-	-	227,267	
12942	System Renewal	Storage	Compressor Equipment	SCOR:Methane Vent-Reduce		Y	0	958,542	1,026,964	-	-	-	
12947	System Renewal	Storage	Compressor Equipment	SCOR:100MOV Yard Valve-Replace		N	38	684,997	-	-	-	-	
12948	System Renewal	Storage	Compressor Equipment	SCOR:100MOV Yard Valve-Replace		N	33	-	392,909	-	-	-	
12949	System Renewal	Storage	Compressor Equipment	SCOR:100MOV Yard Valve-Replace		N	33	-	-	392,909	-	-	
12950	System Renewal	Storage	Compressor Equipment	SCOR:100MOV Yard Valve-Replace		N	33	-	-	-	392,909	-	
12956	System Renewal	Storage	Compressor Equipment	SCOR:100MOD Hdr Valves-Replace		N	103	-	1,041,884	-	-	-	
12957	System Renewal	Storage	Compressor Equipment	SCOR:100MOD Hdr Valves-Replace		N	106	-	100,000	5,118,230	-	-	
12958	System Renewal	Storage	Compressor Equipment	SCOR:100MOD Hdr Valves-Replace		N	100	-	-	100,000	3,766,880	-	
12959	System Renewal	Storage	Compressor Equipment	SCOR:100MOD Hdr Valves-Replace		N	108	-	-	-	100,000	3,766,880	
12960	System Renewal	Storage	Compressor Equipment	SCOR:100MOD Hdr Valves-Replace		N	104	-	-	-	-	50,000	
12975	System Renewal	Storage	Compressor Equipment	SCOR:622xx Bypass Valve-Upgrade		N	85	-	-	-	264,000	-	
12977	System Renewal	Storage	Compressor Equipment	SCOR:622xx Bypass Valve-Upgrade		N	85	-	-	-	-	264,000	
13006	System Renewal	Storage	Compressor Equipment	SCOR:525 UPS-Replace		N	73	-	132,000	-	-	-	
13007	System Renewal	Storage	Compressor Equipment	SCOR:525 UPS-Replace		N	73	-	-	-	-	132,000	
13013	System Renewal	Storage	Compressor Equipment	SCOR:810002 IDC-Replace		N	41	-	-	-	-	660,000	
13014	System Renewal	Storage	Compressor Equipment	SCOR:800 Bldg1 I/O Connection-Replace		N	17307	250,800	-	-	-	-	
13031	System Renewal	Storage	Compressor Equipment	SCOR:MCC3 APU PLC-Rplace		N	0	-	462,000	-	-	-	
13047	System Renewal	Storage	Wells and Well Equipment	PSEC:TS23H Well-Install		N	63	-	-	-	-	605,000	
13048	System Renewal	Storage	Field Lines	LSEC:TS23H G/L-Modify		N	63	-	-	-	-	47,500	
16784	System Renewal	Storage	Field Lines	MM:ESD Bottles-Upgrade		Y	113	120,000	-	-	-	-	

Project Listing for EGD (2019-2023)

Business Case ID	Investment Category	Asset Class	Asset Program	Project Name	ICM - Eligible	Mandatory	LRROI (%)	2019 ($)	2020 ($)	2021 ($)	2022 ($)	2023 ($)	Potential for LTC
16785	System Renewal	Storage	Field Lines	MM:ESD Bottles-Upgrade		Y	113	-	120,000	-	-	-	
16803	System Renewal	Storage	Compressor Equipment	SCOR:512K725-O/H		Y	0	40,000	-	-	-	-	
16806	System Renewal	Storage	Field Lines	MM:ESD Bottles-Upgrade		Y	113	-	-	120,000	-	-	
16807	System Renewal	Storage	Field Lines	MM:ESD Bottles-Upgrade		Y	113	-	-	-	120,000	-	
16808	System Renewal	Storage	Field Lines	MM:ESD Bottles-Upgrade		Y	113	-	-	-	-	120,000	
16825	System Renewal	Storage	Wells and Well Equipment	PSEC:Well Tools-Purchase		Y	0	84,000	-	-	-	-	
16826	System Renewal	Storage	Wells and Well Equipment	PCOR:Well Tools-Purchase		Y	0	-	36,000	-	-	-	
16827	System Renewal	Storage	Wells and Well Equipment	PDOW:Well Tools-Purchase		N	17	-	-	108,000	-	-	
16828	System Renewal	Storage	Wells and Well Equipment	PSKC:Well Tools-Purchase		Y	0	-	-	-	96,000	-	
16829	System Renewal	Storage	Wells and Well Equipment	PMKC:Well Tools-Purchase		Y	0	-	-	-	-	96,000	
16835	System Renewal	Storage	Field Lines	LM:Lateral Separator-Build		N	45	-	-	-	-	950,000	
16837	System Service	Storage	Integrity Initiatives - Storage	LCRW:P/L-ILI Retrofits		Y	0	-	-	500,000	-	-	
18103	System Renewal	Storage	Compressor Equipment	SCRW:Noise-Mitigate		Y	0	250,000	-	-	-	-	
18183	System Renewal	Storage	Compressor Equipment	SCOR:Storage Renewal-FEED		Y	0	2,500,000	-	-	-	-	
19128	System Renewal	Storage	Compressor Equipment	SCOR:61005 Crankshaft-Replace		N	521	3,125,621	-	-	-	-	
19383	System Renewal	Storage	Compressor Equipment	SCOR:525 UPS-Replace		N	73	-	-	132,000	-	-	
19384	System Renewal	Storage	Compressor Equipment	SCOR:525 UPS-Replace		N	73	-	-	-	132,000	-	
19391	System Renewal	Storage	Compressor Equipment	SCOR:60004 iBalance-Upgrade		N	338	-	-	-	-	396,900	
3222	General Plant	TIS	IT Implementation	Business Objects Upgrade and Enhancements		Y	246	-	50,000	-	-	-	
3224	General Plant	TIS	IT Implementation	Data Lake and WAMS DataMart Enhancements		N	121	700,000	250,000	250,000	-	-	
3245	General Plant	TIS	IT Implementation	EnMar Replacement		Y	209	200,000	-	-	-	-	
3246	General Plant	TIS	IT Implementation	GIS/GPS releases		N	138	-	-	250,000	-	-	
3255	General Plant	TIS	IT Implementation	SCADA Replacement Project		Y	158	2,500,000	-	-	-	-	
3284	General Plant	TIS	IT Implementation	Ops Small apps releases		N	0	250,000	500,000	-	-	-	
5583	General Plant	TIS	IT Implementation	CIS Hardware Replacement		N	118	10,000,000	-	-	-	-	
5584	General Plant	TIS	IT Implementation	HANA Software Implementation		N	168	6,400,000	4,000,000	-	-	-	
5646	General Plant	TIS	IT Implementation	Microsoft SQL Server Software Upgrade		N	148	150,000	-	-	-	-	
5647	General Plant	TIS	IT Implementation	Oracle Middleware Upgrades		N	186	-	-	350,000	-	-	
5681	General Plant	TIS	IT Implementation	Oracle Database Software Upgrade		N	291	-	270,000	-	-	-	
5685	General Plant	TIS	IT Implementation	ETL Tools and Enhancements		N	222	300,000	-	-	-	-	
5949	General Plant	TIS	IT Implementation	CS&C Initiatives		Y	184	400,000	650,000	550,000	250,000	-	
5968	General Plant	TIS	IT Implementation	WAMS stabilization & releases (2018 - 2027)		Y	106	2,500,000	3,000,000	3,000,000	-	-	
6049	General Plant	TIS	IT Implementation	Asset Management IT		N	480	800,000	800,000	800,000	-	-	
8551	General Plant	TIS	IT Implementation	SAP BW Enhancements		Y	90	200,000	-	5,000,000	-	-	
8576	General Plant	TIS	IT Implementation	IT Meeting Room AV Sustainment		N	260	-	-	740,000	-	-	
8601	General Plant	TIS	IT Implementation	System Measurement Systems		Y	133	200,000	200,000	200,000	-	-	

Project Listing for EGD (2019-2023)

Business Case ID	Investment Category	Asset Class	Asset Program	Project Name	ICM - Eligible	Mandatory	LRROI (%)	2019 ($)	2020 ($)	2021 ($)	2022 ($)	2023 ($)	Potential for LTC
8602	General Plant	TIS	IT Implementation	Operation Digital		N	188	1,300,000	3,000,000	1,000,000	-	-	
8603	General Plant	TIS	IT Implementation	Engineering Application/Network Analysis/Land Management Releases		N	164	500,000	500,000	500,000	-	-	
8683	General Plant	TIS	IT Implementation	Customer Experience Transformation (Digital) (includes all business cost and Accenture cost)		N	184	7,000,000	-	-	-	-	
8684	General Plant	TIS	IT Implementation	Mobile Records / Records Access in the Field		N	111	-	-	1,500,000	-	-	
8923	General Plant	TIS	IT Implementation	IT - 00 - Desktop Sustainment (2018 - 2027)		Y	123	400,000	400,000	400,000	-	-	
8925	General Plant	TIS	IT Implementation	IT - 00 - Desktop Replacement (2018 - 2028)		Y	122	870,000	2,000,000	1,575,000	-	-	
8926	General Plant	TIS	IT Implementation	IT - 00 - Mobile Devices (2018 - 2027)		Y	121	250,000	250,000	250,000	-	-	
8927	General Plant	TIS	IT Implementation	IT - 00 - Microsoft Enterprise Agreement (2018 - 2027)		Y	72	1,300,000	1,300,000	1,300,000	-	-	
8944	General Plant	TIS	IT Implementation	Records Storage Repository 2018		N	1108	400,000	-	-	-	-	
9307	General Plant	TIS	IT Implementation	Gas Storage Business Solutions (2019)		N	179	500,000	-	-	-	-	
9308	General Plant	TIS	IT Implementation	Gas Storage Business Solutions (2020)		N	179	-	400,000	-	-	-	
9309	General Plant	TIS	IT Implementation	Gas Storage Business Solutions (2021)		N	179	-	-	400,000	-	-	
9318	General Plant	TIS	IT Implementation	Finance Business Solutions (2019)		N	131	220,000	-	-	-	-	
9319	General Plant	TIS	IT Implementation	Finance Business Solutions (2020)		N	131	-	450,000	-	-	-	
9321	General Plant	TIS	IT Implementation	Finance Business Solutions (2021)		N	131	-	-	520,000	-	-	
9341	General Plant	TIS	IT Implementation	Customer Care Information System (CIS) Business Solutions (2019 -2021)		Y	91	400,000	400,000	800,000	800,000	-	
9344	General Plant	TIS	IT Implementation	Integrity Business Solutions (2019)		N	130	225,000	225,000	-	-	-	
9346	General Plant	TIS	IT Implementation	Integrity Business Solutions (2020)		N	130	-	750,000	-	-	-	
9348	General Plant	TIS	IT Implementation	Integrity Business Solutions (2021)		N	130	-	-	550,000	-	-	
9683	General Plant	TIS	IT Implementation	GIS/GPS Upgrades		Y	93	1,000,000	1,000,000	-	-	-	
11403	General Plant	TIS	IT Implementation	EQMT Upgrade & Enhancements		N	0	-	200,000	-	-	-	
15803	General Plant	TIS	IT Implementation	Project Portfolio Optimization		N	480	-	500,000	-	-	-	
16704	General Plant	TIS	IT Implementation	Major projects & Planning TIS program		N	55	300,000	300,000	500,000	360,000	-	
16705	General Plant	TIS	IT Implementation	NetOps TIS program		N	68	100,000	500,000	200,000	500,000	-	
16706	General Plant	TIS	IT Implementation	Telemetry Security Improvements		Y	0	200,000	-	-	-	-	
16710	General Plant	TIS	IT Implementation	Distribution Protection and Operations Services TIS Program		Y	52	300,000	600,000	500,000	360,000	-	
16718	General Plant	TIS	IT Implementation	Extranet Releases (2021-2028)		N	863	-	-	400,000	-	-	
17943	General Plant	TIS	IT Implementation	IT Business Applications Upgrades, Enhancement Projects, Infrastructure Upgrades (2022-2028)		Y	0	-	-	-	22,141,286	22,141,286	
19323	General Plant	TIS	IT Implementation	Small Application Upgrade		Y	0	20,000	-	-	-	-	

Project Listing for UGL (2019-2023)

Unique Identifier	Investment Category	Asset/Growth Category	Portfolio	Description	ICM - Eligible	Mandatory	Priority	2019 ($)	2020 ($)	2021 ($)	2022 ($)	2023 ($)	Potential for LTC
859	System Access	CNG	CNG	CNG Refueling Stations Placeholder		Y	1	1,000,000	-	-	-	-	
1439	System Access	CNG	CNG	CNG Refueling Stations Placeholder		Y	1	-	2,250,000	1,875,000	1,875,000	-	
21	System Service	Compression & Dehy	Compressor and Dehy Capital Maintenance	STO ABSENT TANK INSTALLS - VARIOUS		Y	1	364,418	-	-	-	-	
166	System Renewal	Compression & Dehy	Cathodic Protection Advancements	STO CATHODIC PROTECTION		Y	1	117,748	117,748	117,748	117,748	117,748	
209	System Renewal	Compression & Dehy	Station Painting	STO - HPC		Y	1	700,000	-	-	-	-	
225	System Renewal	Compression & Dehy	Compressor Overhauls	Dawn PltC PowerTurb&Inboard CompOverhaul		N	2	-	-	-	364,110	-	
226	System Renewal	Compression & Dehy	Compressor Overhauls	Bright A2 Compressor Engine Overhaul		N	2	-	-	-	-	2,809,080	
370	General Plant	Compression & Dehy	Tools	STO COMPRESSOR EAST TOOL ADDITIONS		N	2	66,774	-	-	-	-	
372	General Plant	Compression & Dehy	Tools	STO CAPITAL TOOLS ADDITIONS -TECHNICIANS		N	2	22,258	-	-	-	-	
373	General Plant	Compression & Dehy	Tools	STO CAPITAL TOOLS ADDITIONS - Mech		N	2	22,258	-	-	-	-	
392	General Plant	Compression & Dehy	Tools	STO CAPITAL TOOLS REPL - TECH WEST		N	2	22,258	-	-	-	-	
393	General Plant	Compression & Dehy	Tools	STO CAPITAL TOOLS REPL - Mech		N	2	22,258	-	-	-	-	
481	System Renewal	Compression & Dehy	Compressor and Dehy Capital Maintenance	Bright B Lube Oil Skid Repalcement		N	2	214,134	-	-	-	-	
482	System Renewal	Compression & Dehy	Compressor and Dehy Capital Maintenance	Bright B Boiler Upgrade		N	3	-	-	800,000	-	-	
483	System Renewal	Compression & Dehy	Compressor and Dehy Capital Maintenance	OSE Compressor Ignition System Upgrade		N	3	-	60,000	-	-	-	
484	System Renewal	Compression & Dehy	Compressor and Dehy Capital Maintenance	STO - Switch Gear Aux 2		N	2	198,248	-	-	-	-	
485	System Renewal	Compression & Dehy	Compressor and Dehy Capital Maintenance	Parkway Siemens MCC replacement		N	3	-	333,856	-	-	-	
489	System Renewal	Compression & Dehy	Compressor and Dehy Capital Maintenance	STO - PLC5 upgrade to ControlLogix		N	2	320,797	-	-	-	-	
499	System Service	Compression & Dehy	Compressor and Dehy Capital Maintenance	Dawn Dehy Plant Process Tank Replacement		N	3	-	234,090	416,160	-	-	
503	System Renewal	Compression & Dehy	Compressor and Dehy Capital Maintenance	Parkway A - Fire/Gas Detection Panel		N	3	-	107,188	-	-	-	
542	System Renewal	Compression & Dehy	Compressor and Dehy Capital Maintenance	LOBO B - Fire/Gas Detection Panel		N	2	112,945	-	-	-	-	
543	System Renewal	Compression & Dehy	Compressor and Dehy Capital Maintenance	Bright B - Fire/Gas Detection Panel		N	2	112,945	-	-	-	-	
546	System Renewal	Compression & Dehy	Compressor and Dehy Capital Maintenance	LOBO A1 - Fire/Gas Detection Panel		N	3	-	112,945	-	-	-	
547	System Renewal	Compression & Dehy	Compressor and Dehy Capital Maintenance	LOBO A2 - Fire/Gas Detection Panel		N	3	-	112,945	-	-	-	
582	System Renewal	Compression & Dehy	Compressor and Dehy Capital Maintenance	Dow A Water Jacket/Coolers		N	3	-	533,394	-	-	-	
598	System Service	Compression & Dehy	Compressor and Dehy Capital Maintenance	STO PARKWAY SAFETY & SECURITY UPGRADES		N	4	50,000	-	-	-	-	
602	System Service	Compression & Dehy	Compressor and Dehy Capital Maintenance	STO SAFETY & SECURITY UPGRADES - VARIOUS		N	4	100,000	-	-	-	-	
604	System Service	Compression & Dehy	Compressor and Dehy Capital Maintenance	STO LED LIGHTING UPGRADES		N	4	152,976	-	-	-	-	
605	System Service	Compression & Dehy	Compressor and Dehy Capital Maintenance	STO LED LIGHTING UPGRADES EASTERN COMP		N	4	87,236	-	-	-	-	
952	System Renewal	Compression & Dehy	Compressor Overhauls	Bright A1 Engine mid-life Overhaul		N	2	-	-	-	-	3,265,871	
956	System Renewal	Compression & Dehy	Compressor Overhauls	Bright B Engine End-of-Life Overhaul		N	2	-	-	-	-	2,288,880	
958	System Renewal	Compression & Dehy	Compressor Overhauls	Bright B PT/Comp Overhaul		N	2	-	-	-	-	364,140	
1055	System Renewal	Compression & Dehy	Obsolete RB211-24A C Plant	Obsolete RB211-24A C Plant	Y	N	3	-	-	-	19,300,000	82,900,000	Y
1063	System Renewal	Compression & Dehy	Compressor Overhauls	Parkway B PT/IB Comp Overhaul		N	2	-	371,423	-	-	-	
1070	System Renewal	Compression & Dehy	Compressor Overhauls	Payne Compressor Overhaul		N	2	-	-	-	-	216,486	
1077	System Renewal	Compression & Dehy	Compressor and Dehy Capital Maintenance	PLC 5 Conversion upgrades		N	3	-	212,242	-	-	-	

Project Listing for UGL (2019-2023)

Unique Identifier	Investment Category	Asset/Growth Category	Portfolio	Description	ICM - Eligible	Mandatory	Priority	2019 ($)	2020 ($)	2021 ($)	2022 ($)	2023 ($)	Potential for LTC
1084	System Renewal	Compression & Dehy	Compressor and Dehy Capital Maintenance	Siemen's MCC's		N	3	-	318,362	324,730	331,224	337,849	
1152	System Renewal	Compression & Dehy	Waubuno	Waubuno	Y	N	2	-	3,183,624	15,154,050	-	-	Y
1194	System Renewal	Compression & Dehy	Compressor Overhauls	Dawn J Plant Engine Overhaul		N	2	-	1,500,000	-	-	-	
1479	General Plant	Compression & Dehy	Tools	STO COMPRESSOR EAST TOOL REPLACEMENTS		N	2	66,774	-	-	-	-	
1539	System Renewal	Compression & Dehy	Compressor and Dehy Capital Maintenance	STO DAWN DEHY TOWER RELIEF VALVE RPLCMT		N	3	-	200,000	-	-	-	
1541	General Plant	Compression & Dehy	Compressor and Dehy Capital Maintenance	STO DAWN WELD SHOP BACKUP GENERATOR		N	3	-	93,256	-	-	-	
1542	System Renewal	Compression & Dehy	Compressor and Dehy Capital Maintenance	STO PARKWAY MAIN CNTRL BLDG FIRE/GAS		N	3	-	112,945	-	-	-	
1543	System Renewal	Compression & Dehy	Compressor and Dehy Capital Maintenance	STO PARKWAY A VIBRATION MONITOR		N	3	-	80,010	-	-	-	
1544	System Renewal	Compression & Dehy	Compressor and Dehy Capital Maintenance	STO PARKWAY A MCC REPLACEMENT		N	2	168,199	-	-	-	-	
1571	System Service	Compression & Dehy	MSAPR EMISSIONS ACTION PLAN	Dow A Compressor– install catalytic convertor		Y	1	110,000	-	-	-	-	
2100	System Renewal	Compression & Dehy	Compressor and Dehy Capital Maintenance	STO-UPS		N	2	-	119,718	119,718	119,718	119,718	
2101	General Plant	Compression & Dehy	Tools	STO-TOOLS		N	2	-	311,612	311,612	311,612	311,612	
2102	System Renewal	Compression & Dehy	Station Painting	STO - HPC all sites		Y	1	-	700,000	700,000	700,000	700,000	
2379	System Service	Compression & Dehy	MSAPR EMISSIONS ACTION PLAN	Edy's Mills Compressor – install catalytic convertor		Y	1	110,000	-	-	-	-	
2380	System Service	Compression & Dehy	MSAPR EMISSIONS ACTION PLAN	Dawn Aux 3 Generator – install catalytic convertor		Y	1	-	110,000	-	-	-	
2381	System Service	Compression & Dehy	MSAPR EMISSIONS ACTION PLAN	Dawn Aux 4-1 Generator – install catalytic convertor		Y	1	-	110,000	-	-	-	
2382	System Service	Compression & Dehy	MSAPR EMISSIONS ACTION PLAN	Oil Springs East Unit 1 Compressor – install catalytic convertor		Y	1	-	-	110,000	-	-	
2383	System Service	Compression & Dehy	MSAPR EMISSIONS ACTION PLAN	Oil Springs East Unit 2 Compressor – install catalytic convertor		Y	1	-	-	110,000	-	-	
2384	System Service	Compression & Dehy	MSAPR EMISSIONS ACTION PLAN	167 Compressor – install catalytic convertor		Y	1	-	-	-	110,000	-	
2385	System Service	Compression & Dehy	MSAPR EMISSIONS ACTION PLAN	Dawn Aux 4-2 Generator – install catalytic convertor		Y	1	-	-	-	-	110,000	
146	General Plant	CRES	Service Facilities Maintenance	South Furniture, Decor & Flooring		Y	1	125,000	125,000	125,000	125,000	125,000	
150	General Plant	CRES	Service Facilities Maintenance	South Grounds & Parking		Y	1	300,000	200,000	200,000	200,000	200,000	
156	General Plant	CRES	Service Facilities Maintenance	South Unplanned Blanket		Y	1	250,000	300,000	300,000	300,000	300,000	
158	General Plant	CRES	Service Facilities Maintenance	South Security		Y	1	500,000	400,000	350,000	400,000	400,000	
159	General Plant	CRES	Service Facilities Maintenance	South Equipment, Controls, Mechanical		Y	1	300,000	500,000	500,000	500,000	700,000	
162	General Plant	CRES	Service Facilities Maintenance	South Roofing, Bldg Envelope, Windows		Y	1	500,000	200,000	200,000	200,000	200,000	
185	General Plant	CRES	Service Facilities Maintenance	North Furniture, Decor & Flooring		Y	1	125,000	125,000	125,000	125,000	125,000	
188	General Plant	CRES	Service Facilities Maintenance	North Grounds & Parking		Y	1	200,000	100,000	100,000	100,000	100,000	
192	General Plant	CRES	Service Facilities Maintenance	North Unplanned Blanket		Y	1	250,000	200,000	200,000	200,000	200,000	
194	General Plant	CRES	Service Facilities Maintenance	North Equipment, Controls, Mechanical		Y	1	300,000	500,000	500,000	500,000	600,000	
197	General Plant	CRES	Service Facilities Maintenance	North Roofing, Bldg Envelope, Windows		Y	1	300,000	200,000	200,000	200,000	200,000	
1161	General Plant	CRES	Service Facilities Modernization	50 Keil Drive Modernization		Y	1	-	4,000,000	5,000,000	5,000,000	5,000,000	
1167	General Plant	CRES	Service Facilities Modernization	Dawn North Administration Modernization		Y	1	-	-	2,850,000	5,300,000	-	
1171	General Plant	CRES	Service Facilities Modernization	Orillia - New Building		Y	1	-	-	-	1,500,000	5,000,000	
1493	General Plant	CRES	New Service Facilities	CS-Belleville PropertyPurch&Eng.		Y	1	3,451,681	-	-	-	-	
1546	General Plant	CRES	Service Facilities Modernization	50 Keil CCHP Equipment		Y	1	5,739,347	-	-	-	-	

Project Listing for UGL (2019-2023)

Unique Identifier	Investment Category	Asset/Growth Category	Portfolio	Description	ICM - Eligible	Mandatory	Priority	2019 ($)	2020 ($)	2021 ($)	2022 ($)	2023 ($)	Potential for LTC
1547	General Plant	CRES	Service Facilities Maintenance	50 Keil LED Lighting Replacement		Y	1	1,000,000	-	-	-	-	
1548	General Plant	CRES	Service Facilities Maintenance	50 Keil Parking Lot - Final Phase		Y	1	1,400,000	-	-	-	-	
1549	General Plant	CRES	Service Facilities Maintenance	North Security		Y	1	250,000	100,000	100,000	100,000	100,000	
1985	General Plant	CRES	New Service Facilities	Belleville - New Building		Y	1	-	3,500,000	4,000,000	-	-	
1986	General Plant	CRES	Service Facilities Modernization	Cambridge - Refurbishment		Y	1	-	3,450,000	-	-	-	
1987	General Plant	CRES	Service Facilities Modernization	Guelph - Refurbishment		Y	1	-	-	-	-	1,500,000	
1991	General Plant	CRES	Service Facilities Maintenance	North LED Lighting Conversions		Y	1	-	75,000	75,000	75,000	75,000	
1992	General Plant	CRES	Service Facilities Maintenance	South LED Lighting Conversions		Y	1	-	125,000	125,000	125,000	125,000	
1993	General Plant	CRES	Service Facilities Maintenance	Facility Assessments		Y	1	-	50,000	50,000	50,000	50,000	
2410	General Plant	CRES	Service Facilities Maintenance	Hamilton Park St		Y	1	-	850,000	-	-	-	
211	System Service	Distribution Growth	Distribution Reinforcement	Sudbury Lateral Repl *C/O 2018*	Y	Y	1	3,000,000	-	-	-	-	
457	System Service	Distribution Growth	Station Reinforcement	HALT-ThirdLine&UpperMiddleStn18Y-231R-Oa		Y	1	451,880	-	-	-	-	
473	System Service	Distribution Growth	Distribution Reinforcement	Powassan-TBS		Y	1	-	520,516	-	-	-	
614	System Service	Distribution Growth	Station Reinforcement	LOND: Ingersol Trans Regulator Replaceme		Y	1	-	500,829	-	-	-	
732	System Access	Distribution Growth	General Customer Growth	Plan-(B)-Dist-Addn-Contr-NB-Scattered		Y	1	1,206,994	-	-	-	-	
733	System Access	Distribution Growth	General Customer Growth	Service Installations-Random-Contractor		Y	1	1,860,405	-	-	-	-	
734	System Access	Distribution Growth	General Customer Growth	Land Rights-Additions		Y	1	27,198	-	-	-	-	
735	System Access	Distribution Growth	General Customer Growth	Meter & Regulator Inst-Addn-Company		Y	1	690,540	-	-	-	-	
736	System Access	Distribution Growth	General Customer Growth	Indirect Materials-Additions		Y	1	130,907	-	-	-	-	
737	System Access	Distribution Growth	General Customer Growth	WIND Generic Greenhouse Windsor		Y	1	1,696,586	-	-	-	-	
738	System Access	Distribution Growth	General Customer Growth	Plan-(B)-Dist-Addn-Contr-NB-Scattered		Y	1	200,658	-	-	-	-	
739	System Access	Distribution Growth	General Customer Growth	Service Installations-Random-Contractor		Y	1	216,156	-	-	-	-	
740	System Access	Distribution Growth	General Customer Growth	Meter & Regulator Inst-Addn-Company		Y	1	131,768	-	-	-	-	
741	System Access	Distribution Growth	General Customer Growth	Indirect Materials-Additions		Y	1	21,769	-	-	-	-	
742	System Access	Distribution Growth	General Customer Growth	Plan-(B)-Dist-Addn-Contr-NB-Scattered		Y	1	120,163	-	-	-	-	
743	System Access	Distribution Growth	General Customer Growth	Service Installations-Random-Contractor		Y	1	451,844	-	-	-	-	
744	System Access	Distribution Growth	General Customer Growth	Land Rights-Additions		Y	1	5,000	-	-	-	-	
745	System Access	Distribution Growth	General Customer Growth	Meter & Regulator Inst-Addn-Company		Y	1	144,936	-	-	-	-	
746	System Access	Distribution Growth	General Customer Growth	Plan-(B)-Dist-Addn-Contr-NB-Scattered		Y	1	1,345,186	-	-	-	-	
747	System Access	Distribution Growth	General Customer Growth	Plan-(B)-Dist-Addn-NB Scattered-Other		Y	1	95,895	-	-	-	-	
748	System Access	Distribution Growth	General Customer Growth	Service Installations-Random-Contractor		Y	1	3,768,849	-	-	-	-	
749	System Access	Distribution Growth	General Customer Growth	Land Rights-Additions		Y	1	20,000	-	-	-	-	
750	System Access	Distribution Growth	General Customer Growth	Meter & Regulator Inst-Addn-Company		Y	1	1,214,982	-	-	-	-	
751	System Access	Distribution Growth	General Customer Growth	Meter & Regulator Inst-Addn-Contractor		Y	1	35,627	-	-	-	-	
752	System Access	Distribution Growth	General Customer Growth	Indirect Materials-Additions		Y	1	300,000	-	-	-	-	
753	System Service	Distribution Growth	Distribution Reinforcement	LOND: Southdale & Bostwick Reinforcement		Y	1	-	-	-	-	258,829	

Project Listing for UGL (2019-2023)

Unique Identifier	Investment Category	Asset/Growth Category	Portfolio	Description	ICM - Eligible	Mandatory	Priority	2019 ($)	2020 ($)	2021 ($)	2022 ($)	2023 ($)	Potential for LTC
755	System Access	Distribution Growth	General Customer Growth	LOND: New Business Additions		Y	1	618,445	-	-	-	-	
756	System Access	Distribution Growth	General Customer Growth	LOND: Verasen Contract Customer Load Add		Y	1	-	329,009	-	-	-	
757	System Access	Distribution Growth	General Customer Growth	Plan-(B)-Dist-Addn-Contr-NB-Scattered		Y	1	189,975	-	-	-	-	
758	System Access	Distribution Growth	General Customer Growth	Service Installations-Random-Contractor		Y	1	1,315,243	-	-	-	-	
759	System Access	Distribution Growth	General Customer Growth	Meter & Regulator Inst-Addn-Company		Y	1	399,282	-	-	-	-	
761	System Access	Distribution Growth	General Customer Growth	Plan-(B)-Dist-Addn-Contr-NB-Scattered		Y	1	1,713,169	-	-	-	-	
762	System Access	Distribution Growth	General Customer Growth	New Business-Services		Y	1	3,951,106	-	-	-	-	
763	System Access	Distribution Growth	General Customer Growth	Land Rights-Additions		Y	1	50,000	-	-	-	-	
764	System Access	Distribution Growth	General Customer Growth	New Business-Meters & Regs		Y	1	1,546,400	-	-	-	-	
765	System Access	Distribution Growth	General Customer Growth	Indirect Materials-Additions		Y	1	318,585	-	-	-	-	
767	System Access	Distribution Growth	General Customer Growth	Plan-(B)-Dist-Addn-Contr-NB-Scattered		Y	1	2,281,320	-	-	-	-	
768	System Access	Distribution Growth	General Customer Growth	Service Installations-Random-Contractor		Y	1	1,823,664	-	-	-	-	
769	System Access	Distribution Growth	General Customer Growth	Land Rights-Additions		Y	1	15,000	-	-	-	-	
770	System Access	Distribution Growth	General Customer Growth	Meter & Regulator Inst-Addn-Company		Y	1	604,104	-	-	-	-	
771	System Access	Distribution Growth	General Customer Growth	Indirect Materials-Additions		Y	1	135,377	-	-	-	-	
772	System Access	Distribution Growth	General Customer Growth	Plan-(B)-Dist-Addn-Contr-NB-Scattered		Y	1	4,134,977	-	-	-	-	
773	System Access	Distribution Growth	General Customer Growth	Service Installations-Random-Contractor		Y	1	3,302,269	-	-	-	-	
774	System Access	Distribution Growth	General Customer Growth	Land Rights-Additions		Y	1	15,000	-	-	-	-	
775	System Access	Distribution Growth	General Customer Growth	Meter & Regulator Inst-Addn-Company		Y	1	736,741	-	-	-	-	
776	System Access	Distribution Growth	General Customer Growth	Indirect Materials-Additions		Y	1	197,509	-	-	-	-	
777	System Service	Distribution Growth	Distribution Reinforcement	HALT-THIRD LINE & NORTH SERVICE-HALT		Y	1	-	-	410,567	-	-	
778	System Access	Distribution Growth	General Customer Growth	Plan-(B)-Dist-Addn-Contr-NB-Scattered		Y	1	1,162,127	-	-	-	-	
779	System Access	Distribution Growth	General Customer Growth	DSD-Plan-(B)-Dist-Addn-Compy-Services		Y	1	848,090	-	-	-	-	
780	System Access	Distribution Growth	General Customer Growth	Plan-(B)-Dist-Addn-Compy-NB-Scattered		Y	1	219,915	-	-	-	-	
781	System Access	Distribution Growth	General Customer Growth	Service Installations -Random Contractor		Y	1	4,975,634	-	-	-	-	
782	System Access	Distribution Growth	General Customer Growth	Land Rights-Additions		Y	1	20,000	-	-	-	-	
783	System Access	Distribution Growth	General Customer Growth	Meter & Regulator Inst-Addn-Company		Y	1	837,861	-	-	-	-	
784	System Access	Distribution Growth	General Customer Growth	Indirect Materials-Company		Y	1	155,806	-	-	-	-	
790	System Access	Distribution Growth	General Customer Growth	SMC-Meter & Regulator Additions South		Y	1	5,345,412	-	-	-	-	
791	System Access	Distribution Growth	General Customer Growth	Plan-(B)-Dist-Addn-Compy-Services		Y	1	1,196,890	-	-	-	-	
792	System Access	Distribution Growth	General Customer Growth	Plan-(B)-Dist-Addn-Compy-NB-Scattered		Y	1	247,671	-	-	-	-	
793	System Access	Distribution Growth	General Customer Growth	Land Rights-Additions		Y	1	15,300	-	-	-	-	
794	System Access	Distribution Growth	General Customer Growth	Meter & Regulator Inst-Addn-Company		Y	1	194,834	-	-	-	-	
795	System Access	Distribution Growth	General Customer Growth	Indirect Materials-Company		Y	1	44,083	-	-	-	-	
796	System Access	Distribution Growth	General Customer Growth	Plan-(B)-Dist-Addn-Contr-NB-Scattered		Y	1	489,239	-	-	-	-	
797	System Access	Distribution Growth	General Customer Growth	Plan-(B)-Dist-NB Scatt Stn		Y	1	3,826	-	-	-	-	

Project Listing for UGL (2019-2023)

Unique Identifier	Investment Category	Asset/Growth Category	Portfolio	Description	ICM - Eligible	Mandatory	Priority	2019 ($)	2020 ($)	2021 ($)	2022 ($)	2023 ($)	Potential for LTC
798	System Access	Distribution Growth	General Customer Growth	Plan-(B)-Dist-Comp-Services		Y	1	181,441	-	-	-	-	
799	System Access	Distribution Growth	General Customer Growth	Plan-(B)-Dist-Addn-Compy-NB-Scattered		Y	1	86,490	-	-	-	-	
800	System Access	Distribution Growth	General Customer Growth	Service Installations-Contractor SSMarie		Y	1	3,327,024	-	-	-	-	
801	System Access	Distribution Growth	General Customer Growth	Land Rights-Additions		Y	1	30,000	-	-	-	-	
802	System Access	Distribution Growth	General Customer Growth	Meter & Regulator Inst-Addn-Company		Y	1	262,180	-	-	-	-	
803	System Access	Distribution Growth	General Customer Growth	Misc Material-Company		Y	1	45,072	-	-	-	-	
804	System Access	Distribution Growth	General Customer Growth	Propane Converstions		Y	1	10,000	-	-	-	-	
805	System Access	Distribution Growth	General Customer Growth	Plan-(B)-Dist-Addn-Compy-Services		Y	1	319,192	-	-	-	-	
806	System Access	Distribution Growth	General Customer Growth	Plan-(B)-Dist-Addn-Compy-NB-Scattered		Y	1	219,496	-	-	-	-	
807	System Access	Distribution Growth	General Customer Growth	Land Rights-Additions		Y	1	15,300	-	-	-	-	
808	System Access	Distribution Growth	General Customer Growth	Meter & Regulator Inst-Addn-Company		Y	1	51,362	-	-	-	-	
809	System Access	Distribution Growth	General Customer Growth	Indirect Materials-Company		Y	1	42,695	-	-	-	-	
810	System Service	Distribution Growth	Distribution Reinforcement	NW_HWY 655 Reinforcement_TIMMINS		Y	1	598,915	-	-	-	-	
811	System Access	Distribution Growth	General Customer Growth	Plan-(B)-Dist-Addn-Contr-NB-Scattered		Y	1	503,334	-	-	-	-	
812	System Access	Distribution Growth	General Customer Growth	Plan-(B)-Dist-NB Scatt Stn		Y	1	3,826	-	-	-	-	
813	System Access	Distribution Growth	General Customer Growth	Service Installations-Contractor Orillia		Y	1	2,978,818	-	-	-	-	
814	System Access	Distribution Growth	General Customer Growth	Land Rights-Additions		Y	1	30,000	-	-	-	-	
815	System Access	Distribution Growth	General Customer Growth	Meter & Regulator Inst-Addn-Company		Y	1	335,278	-	-	-	-	
816	System Access	Distribution Growth	General Customer Growth	Misc Materials-Company		Y	1	45,072	-	-	-	-	
819	System Access	Distribution Growth	General Customer Growth	SMC-Meter & Regulator Additions North		Y	1	1,934,629	-	-	-	-	
821	System Access	Distribution Growth	General Customer Growth	Preferred Design Capital Blanket		Y	1	1,000,000	-	-	-	-	
848	System Access	Distribution Growth	General Customer Growth	Greenstone *C/O 2018*		Y	1	500,000	3,407,000	-	-	-	Y
854	System Access	Distribution Growth	CK Rural	CK Rural Pipeline Extension(DresdenRein)		Y	1	16,206,727	359,000	-	-	-	Y
863	System Service	Distribution Growth	Transmission Reinforcement	WAT - OwenSound Reinforc Ph 4 - c/o2018	Y	Y	1	-	51,042,071	898,000	-	-	Y
1202	System Service	Distribution Growth	Transmission Reinforcement	Dunnville Line Reinforcement Loop 10" reinforcement from outlet of Caledonia Trans, ending at Stoneman Rd	Y	Y	1	-	-	11,000,000	-	-	Y
1494	System Service	Distribution Growth	Kingsville Transmission Reinf Project	WIND_KTRP Road 2 E Reinf_Kingsville		Y	1	2,671,074	-	-	-	-	
1495	System Service	Distribution Growth	Distribution Reinforcement	LOND - Woodstock Reinforcement-Woodstock		Y	1	258,829	-	-	-	-	
1496	System Service	Distribution Growth	Distribution Reinforcement	LOND-Perth Rd 163 Reinforcemnt- St Marys		Y	1	-	129,076	-	-	-	
1497	System Service	Distribution Growth	Distribution Reinforcement	LOND - Iona Gate Looping - Iona		Y	1	60,770	-	-	-	-	
1498	System Service	Distribution Growth	Distribution Reinforcement	BRAN-Pleasant Ridge Syst Reinf,Brant Cty		Y	1	-	388,216	-	-	-	
1499	System Service	Distribution Growth	Distribution Reinforcement	WAT-Elora Fergus System Reinforcement		Y	1	607,851	-	-	-	-	
1500	System Service	Distribution Growth	Distribution Reinforcement	WAT-Breslau System Reinforcement		Y	1	-	1,343,534	-	-	-	
1501	System Service	Distribution Growth	Distribution Reinforcement	WAT-New Hamburg Baden System Reinforcemt		Y	1	-	599,345	-	-	-	
1502	System Service	Distribution Growth	Distribution Reinforcement	WAT-St Jacobs System Reinforcement		Y	1	352,101	-	-	-	-	
1503	System Service	Distribution Growth	Distribution Reinforcement	WAT-Owen Sound System Reinforcement		Y	1	-	143,038	-	-	-	

Project Listing for UGL (2019-2023)

Unique Identifier	Investment Category	Asset/Growth Category	Portfolio	Description	ICM - Eligible	Mandatory	Priority	2019 ($)	2020 ($)	2021 ($)	2022 ($)	2023 ($)	Potential for LTC
1504	System Service	Distribution Growth	Distribution Reinforcement	Wat - Linwood System Reinforcement		Y	1	1,876,417	-	-	-	-	
1505	System Service	Distribution Growth	Station Reinforcement	WAT-Waterloo Gate Stn Reinf 19S-601		Y	1	213,759	-	-	-	-	
1506	System Service	Distribution Growth	Station Reinforcement	WAT-HWY 23 Distribution Stn 21Q-103R		Y	1	-	418,838	-	-	-	
1507	System Service	Distribution Growth	Station Reinforcement	WAT-Guelph West Gate Stn Reinf 19U-201		Y	1	86,125	-	-	-	-	
1508	System Service	Distribution Growth	Distribution Reinforcement	HAMI-Rymal Rd E Reinforcement Hamilton		Y	1	1,724,151	-	-	-	-	
1509	System Service	Distribution Growth	Distribution Reinforcement	HALT-Appleby Line Reinforcement-Oakville		Y	1	354,521	-	-	-	-	
1510	System Service	Distribution Growth	Distribution Reinforcement	HALT-Stocksbridge Reinforcement Oakville		Y	1	33,523	-	-	-	-	
1511	System Service	Distribution Growth	Station Reinforcement	HALT-19Y-303R-2221 Ninth line Station Re		Y	1	68,738	-	-	-	-	
1512	System Service	Distribution Growth	Distribution Reinforcement	King - County Rd 2 - Odessa - Install +/		Y	1	929,258	-	-	-	-	
1513	System Service	Distribution Growth	Distribution Reinforcement	Chippewa Rd West of James St		Y	1	-	792,179	-	-	-	
1514	System Service	Distribution Growth	Station Reinforcement	Airport Rd TBS - SSM		Y	1	7,000	-	-	-	-	
1515	System Service	Distribution Growth	Station Reinforcement	Parkewood Estates PRS - SSM		Y	1	75,817	-	-	-	-	
1516	System Service	Distribution Growth	Distribution Reinforcement	Esten Dr PRS - Elliot Lake		Y	1	-	3,950	-	-	-	
1518	System Service	Distribution Growth	Transmission Reinforcement	Byron Transmission Stn Rebuild Reinf	Y	Y	1	-	-	349,000	15,253,000	-	
1519	System Access	Distribution Growth	General Customer Growth	WAT-Xiniyi Glass Service & Customer Stn		Y	1	-	1,500,000	-	-	-	
1537	System Service	Distribution Growth	Station Reinforcement	Parry Sound TBS		Y	1	453,429	-	-	-	-	
1550	System Service	Distribution Growth	Kingsville Transmission Reinf Project	WIND_KTRP Dependent Customers_Kingsville		Y	1	4,678,168	-	-	-	-	
1551	System Service	Distribution Growth	Kingsville Transmission Reinf Project	WIND_KTRP Graham Side Rd Reinf_Kingsvill		Y	1	1,357,207	-	-	-	-	
1552	System Access	Distribution Growth	General Customer Growth	WIND_CK Expan Dependent Cust_Chatham		Y	1	2,835,253	-	-	-	-	
1553	System Service	Distribution Growth	Transmission Reinforcement	Oxford Looping		Y	1	100,000	-	-	-	-	
1558	System Service	Distribution Growth	Transmission Reinforcement	Stratford Reinforcement *C/O 2018*	Y	Y	1	23,074,784	506,000	-	-	-	Y
1559	System Service	Distribution Growth	Transmission Reinforcement	EPCOR Customer Station		Y	1	2,780,259	-	-	-	-	
1575	System Service	Distribution Growth	Distribution Reinforcement	800 m installed on Tower St South to loop 2" PE on SE side of Fergus		Y	1	-	470,059	-	-	-	
1576	System Service	Distribution Growth	Distribution Reinforcement	Loop with 6" PE out of main station		Y	1	-	101,576	-	-	-	
1577	System Service	Distribution Growth	Distribution Reinforcement	Install 4" PE along Bay St from Alberto to Huron St		Y	1	-	51,678	-	-	-	
1578	System Service	Distribution Growth	Distribution Reinforcement	Extend 4" PE to the bridge. Streets may vary. District to indicate route		Y	1	-	206,712	-	-	-	
1579	System Service	Distribution Growth	Station Reinforcement	• Replace regulators with 4" • Rebuild piping from outlet of filter to downstream isolating valve of each regulator run		Y	1	-	59,586	-	-	-	
1580	System Service	Distribution Growth	Distribution Reinforcement	Install ~750m of 4" PE 420 kPa MOP main from the existing 3" main on Hwy 119 looping the existing 2" main along 40 Line.		Y	1	-	139,762	-	-	-	
1581	System Service	Distribution Growth	Station Reinforcement	Increase capacity to 1000m3/hr and outlet to 310 kPa. Supports growth in Mitchell.		Y	1	-	325,000	-	-	-	
1582	System Service	Distribution Growth	Distribution Reinforcement	Loop part of the existing 8" HP on Guelph Line with 12" S.		Y	1	-	1,885,000	-	-	-	
1583	System Service	Distribution Growth	Distribution Reinforcement	Lay a new main on main street		Y	1	-	55,000	-	-	-	
1584	System Service	Distribution Growth	Distribution Reinforcement	New 4" PE main on Concession Rd 5 W needed to keep system above min pressure due to 374 and 367 5th Concession		Y	1	-	250,000	-	-	-	
1585	System Service	Distribution Growth	Station Reinforcement	New station (~ @ 2317 Khalsa Gate) that is going to be installed instead of Bronte Creek crossing		Y	1	-	600,000	-	-	-	
1586	System Service	Distribution Growth	Station Reinforcement	Replace exisiting heater with a new cwt 385 MBTU Heater		Y	1	-	275,000	-	-	-	

Project Listing for UGL (2019-2023)

Unique Identifier	Investment Category	Asset/Growth Category	Portfolio	Description	ICM - Eligible	Mandatory	Priority	2019 ($)	2020 ($)	2021 ($)	2022 ($)	2023 ($)	Potential for LTC
1588	System Service	Distribution Growth	Distribution Reinforcement	Continue the reinforcement from 2018, tying into the 8" main along Oxford St		Y	1	-	110,000	-	-	-	
1589	System Service	Distribution Growth	Station Reinforcement	Rebuild both regulator runs to larger orifices and new relief valves and stacks.		Y	1	-	5,500	-	-	-	
1590	System Service	Distribution Growth	Station Reinforcement	Pushing station too hard - modifications in 2018 to get to 2020 max. Requires a full rebuild by 2019/2020 to a 9.S-144H with a CWT heater installed.		Y	1	-	520,516	-	-	-	
1591	System Service	Distribution Growth	Station Reinforcement	Rebuild both regulator runs to larger orifices and new relief valves and stacks.		Y	1	-	5,500	-	-	-	
1594	System Service	Distribution Growth	Distribution Reinforcement	Adding second feed from 1210kPa system using new station to cut to 420kPa. New main connecting station and development.		Y	1	-	138,600	-	-	-	
1595	System Service	Distribution Growth	Station Reinforcement	A new station 9S-142 required considering current/future flow.		Y	1	-	76,000	-	-	-	
1596	System Service	Distribution Growth	Station Reinforcement	This station was partially built in 2016. Station can handle flow for future but need to verify that both regulator's orifice size is 4.8 mm. If not, orifice size needs to changed to 4.8 mm		Y	1	-	500	-	-	-	
1597	System Service	Distribution Growth	Station Reinforcement	Existing orifice (6.4 mm) needs to be changed to 9.5 mm to provide required load for future		Y	1	-	500	-	-	-	
1598	System Service	Distribution Growth	Station Reinforcement	Increase Station Capacity		Y	1	-	107,980	-	-	-	
1599	System Service	Distribution Growth	Distribution Reinforcement	6" Main extension from Windsor Line (Provincial & Concession Rd 8) to the Mega Hospital Site. Please include a tie-in to the 2" main at Baseline & Concession Rd 8. New Station required.		Y	1	-	2,386,992	-	-	-	Y
1600	System Service	Distribution Growth	Distribution Reinforcement	Loop existing 6" ST along County Rd 14 from the outlet of 04E-102 County Rd 14 Stn to the 6" ST along Hwy 77 (FID 517370824)		Y	1	-	1,156,539	-	-	-	
1601	System Service	Distribution Growth	Distribution Reinforcement	Install 4"PE along Watson Pkwy to Speedvale Ave		Y	1	-	-	106,458	-	-	
1602	System Service	Distribution Growth	Distribution Reinforcement	Install 4"PE along Elm St		Y	1	-	-	62,101	-	-	
1603	System Service	Distribution Growth	Station Reinforcement	Station to be rebuild with 9.S-144, will required land purchase. Provisions for heat will be added but not heater provided		Y	1	-	-	498,474	-	-	
1604	System Service	Distribution Growth	Station Reinforcement	This station should be rebuilt similarly to 9.S-147 with an additional regulator run, inlet piping to stay the current NPS8, outlet piping will be NPS10 • Removal of current building • Complete rebuild of both sets of regulator runs to monitor operator setup • Addition of a third regulator run • Replace existing 8” station piping to 10” to exit of station • Replacement of filter • Reworking of electrical and additional heat trace • New Heater		Y	1	-	-	745,988	-	-	
1605	System Service	Distribution Growth	Station Reinforcement	Increase capacity due to growth in Simcoe		Y	1	-	-	275,159	-	-	
1606	System Service	Distribution Growth	Station Reinforcement	Increase capacity due to growth in Brantford		Y	1	-	-	812,160	-	-	
1607	System Service	Distribution Growth	Distribution Reinforcement	Connect existing mains along Robinson Rd		Y	1	-	-	210,000	-	-	
1608	System Service	Distribution Growth	Distribution Reinforcement	Payne Mills - 2550m NPS 8 ST from Payne Mills along Dutton Lines		Y	1	-	-	1,785,000	-	-	
1609	System Service	Distribution Growth	Distribution Reinforcement	Looping on main St is required to maintain system pressure. 101m is the min length of looping required to keep system min until 2026. More is recommended to avoid having to lay main in this area.		Y	1	-	-	380,000	-	-	
1610	System Service	Distribution Growth	Station Reinforcement	Can reduce min inlet to 860 kpa (from 1035 kPa) and		Y	1	-	-		-	-	

Project Listing for UGL (2019-2023)

Unique Identifier	Investment Category	Asset/Growth Category	Portfolio	Description	ICM - Eligible	Mandatory	Priority	2019 ($)	2020 ($)	2021 ($)	2022 ($)	2023 ($)	Potential for LTC
				increase trim size to 100%.						500			
1611	System Service	Distribution Growth	Distribution Reinforcement	Lay new 4" main to sustain new development		Y	1	-	-	150,000	-	-	
1612	System Service	Distribution Growth	Station Reinforcement	Increase outlet pressure to 380 in order to maintain system min		Y	1	-	-	500,000	-	-	
1613	System Service	Distribution Growth	Station Reinforcement	Install new station to feed into the area near 10246 Glendon Dr. Previously 2017 project, but subdivisions have not started yet. Project should be brought forward to align with new subdivisions.		Y	1	-	-	250,000	-	-	
1614	System Service	Distribution Growth	Distribution Reinforcement	Install new main to feed from new station. Previously 2017 project, but subdivisions have not started yet. Project should be brought forward to align with new subdivisions.		Y	1	-	-	64,238	-	-	
1615	System Service	Distribution Growth	Distribution Reinforcement	Connecting two 1210 kPa MOP systems with 2" ST (from FID#552379785 to FID#552380650)		Y	1	-	205,689	-	-	-	
1616	System Service	Distribution Growth	Distribution Reinforcement	Looping existing 2" ST (FID#801879687) with 4" ST		Y	1	-	-	385,841	-	-	
1617	System Service	Distribution Growth	Distribution Reinforcement	Continuation of 2019 4"ST looping		Y	1	-	-	-	-	254,205	
1618	System Service	Distribution Growth	Distribution Reinforcement	Looping existing 2" PE (FID#804313689) with 4"PE		Y	1	-	-	62,500	-	-	
1619	System Service	Distribution Growth	Distribution Reinforcement	Looping existing 3" ST (FID 517100121) with 4" ST		Y	1	-	-	520,000	-	-	
1620	System Service	Distribution Growth	Station Reinforcement	A full rebuild required with 9S-150FR		Y	1	-	-	13,900	-	-	
1621	System Service	Distribution Growth	Station Reinforcement	Increase Station Capacity		Y	1	-	-	418,000	-	-	
1622	System Service	Distribution Growth	Distribution Reinforcement	Loop existing 6" ST420kPa along Seacliff from Graham to near Summers Ave		Y	1	-	-	722,924	-	-	
1623	System Service	Distribution Growth	Distribution Reinforcement	Kingsville - Run new 8" ST along Graham & Road 4 E from the capped 8" at Graham Sdrd & Road 4 E (FID 516519428) to the 4" ST at the intersection of County Rd 31 & Graham		Y	1	-	-	1,357,207	-	-	
1624	System Service	Distribution Growth	Distribution Reinforcement	Loop existing 2"PE with 6"PE along Victoria Rd S		Y	1	-	-	-	350,220	-	
1625	System Service	Distribution Growth	Distribution Reinforcement	Guelph - Loop existing 12" ST along Woodlawn Rd W		Y	1	-	-	-	1,185,380	-	Y
1626	System Service	Distribution Growth	Distribution Reinforcement	Tie 4" PE to 2" PE at bridge st		Y	1	-	-	-	18,275	-	
1627	System Service	Distribution Growth	Station Reinforcement	• Replace heater with 3" Coil • Replace inlet piping to heater		Y	1	-	-	-	86,475	-	
1628	System Service	Distribution Growth	Station Reinforcement	• Remove current CWT 380 and add CWT 770 heater • Add two new regulator runs with two cuts Cut 1. Monitor operator cut from 6160 MOP to 3450 MOP Cut 2. Monitor operator cut from 3450 MOP to 480 MOP • Add ~350ft of NPS 12 piping parallel to current NPS 8 • Abandon NPS 8 Piping and remove current reg runs		Y	1	-	-	-	574,894	-	
1629	System Service	Distribution Growth	Station Reinforcement	• Station to be rebuild with 9.S-142 • Land should be purchased for this station size		Y	1	-	-	-	68,437	-	
1630	System Service	Distribution Growth	Station Reinforcement	Increase Capacity at Tupperville Trans		Y	1	-	-	-	150,200	-	
1631	System Service	Distribution Growth	Distribution Reinforcement	loop existing 2" ST along Main St from the 4" on Graham Rd to the small section of 4" along Main St (FID 517954237)		Y	1	-	-	-	153,664	-	
1632	System Service	Distribution Growth	Distribution Reinforcement	Lay 4" PE main on Main St N. This pipe needs to connect back into the existing 2" (FID 554264151)		Y	1	-	-	-	75,000	-	
1633	System Service	Distribution Growth	Distribution Reinforcement	Loop existing 2" to allow for new developments from outlet of 19Y-303R on Ninth Line.		Y	1	-	-	-	150,000	-	
1634	System Service	Distribution Growth	Station Reinforcement	Beachville Gate (14R-101) increase capacity		Y	1	-	-	-	280,000	-	
1635	System Service	Distribution Growth	Distribution Reinforcement	North London install 600m 4" PE.		Y	1	-	-	-	24,546	-	

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Unique Identifier	Investment Category	Asset/Growth Category	Portfolio	Description	ICM - Eligible	Mandatory	Priority	2019 ($)	2020 ($)	2021 ($)	2022 ($)	2023 ($)	Potential for LTC
1636	System Service	Distribution Growth	Distribution Reinforcement	Sudbury - Install 4" PE through existing 8" casing along Long Lake Rd - PHASE 2		Y	1	-	-	-	1,000,000	-	
1637	System Service	Distribution Growth	Station Reinforcement	Full Rebuild to a 142 size station		Y	1	-	-	-	75,000	-	
1640	System Service	Distribution Growth	Station Reinforcement	With current setup, station cannot support 380 kPa Max. Sust. rebuild required for increased load with 380 max sust based on 9S-150TC		Y	1	-	-	-	28,000	-	
1641	System Service	Distribution Growth	Station Reinforcement	Station is flagged for IOPP. A partial rebuild required.		Y	1	-	-	-	12,000	-	
1642	System Service	Distribution Growth	Station Reinforcement	With current setup, station cannot support 380 kPa Max. Sust. rebuild required for increased load with 380 max sust based on 9S-142		Y	1	-	-	-	76,000	-	
1643	System Service	Distribution Growth	Distribution Reinforcement	Continue looping along Seacliff Dr from the end of the 2021 reinforcement to the 6" ST along Union Ave		Y	1	-	-	-	1,161,523	-	
1644	System Service	Distribution Growth	Distribution Reinforcement	Install 6" PE along Whippoorwill Dr tie-ing into existing station 20S-603		Y	1	-	-	-	-	90,181	
1645	System Service	Distribution Growth	Distribution Reinforcement	Loop existing 2" PE with 6" PE on Arkell Rd		Y	1	-	-	-	-	152,614	
1646	System Service	Distribution Growth	Distribution Reinforcement	Install 4" St down Wellington Rd 7 to 1st line. Buy station property		Y	1	-	-	-	-	340,464	
1647	System Service	Distribution Growth	Station Reinforcement	• Station to be rebuild with 9.S-142 • Land should be purchased for this station size		Y	1	-	-	-	-	69,263	
1648	System Service	Distribution Growth	Station Reinforcement	Station to be rebuild with 9.S-144H		Y	1	-	-	-	-	514,951	
1649	System Service	Distribution Growth	Station Reinforcement	Station to be rebuild with 9.S-150FR		Y	1	-	-	-	-	11,598	
1650	System Service	Distribution Growth	Station Reinforcement	Similar station to 18S-374 in 2018		Y	1	-	-	-	-	818,321	
1651	System Service	Distribution Growth	Distribution Reinforcement	Brantford - Loop out of Brantford Balmoral Gate - phase 1		Y	1	-	-	-	-	1,600,000	
1652	System Service	Distribution Growth	Station Reinforcement	Increase the capacity of the station from 3000 to 4000 to handle increase flow from the 2020 main reinforcement.		Y	1	-	-	-	-	300,000	
1653	System Service	Distribution Growth	Distribution Reinforcement	Road crossing on Mill St W (@ Birchway Pl) to help pressure in subdivision		Y	1	-	-	-	-	25,000	
1654	System Service	Distribution Growth	Station Reinforcement	Increase capacity through a station rebuild. The flow in this station may impact the capacity on the Hamilton HP line		Y	1	-	-	-	-	400,000	
1655	System Service	Distribution Growth	Distribution Reinforcement	lay new 4" main to sustain new development		Y	1	-	-	-	-	150,000	
1657	System Service	Distribution Growth	Distribution Reinforcement	Install 930m 6" PE.		Y	1	-	-	-	-	248,490	
1658	System Service	Distribution Growth	Distribution Reinforcement	Assume Hartley Farm and Sally Creek will be installed		Y	1	-	-	-	-	44,182	
1659	System Service	Distribution Growth	Station Reinforcement	Increase capacity of London Westmount to handle increase flow from main reinforcement (13O-402)		Y	1	-	-	-	-	240,000	
1660	System Service	Distribution Growth	Distribution Reinforcement	Loop existing 4" Steel (FID 552078657) with 6" Steel	Y	Y	1	-	-	-	-	15,000,000	Y
1663	System Service	Distribution Growth	Distribution Reinforcement	Add 4" PE road crossing to backfeed subdivision		Y	1	-	-	-	-	8,750	
1664	System Service	Distribution Growth	Station Reinforcement	*Outlet MOP in SAP is 550 kPa and GIS shows 420 kPa. For a 420 kPa Outlet MOP we cannot achieve 380 kPa Max Sust. It requires a full rebuild of 9S-150FR with 627F.		Y	1	-	-	-	-	13,000	
1665	System Service	Distribution Growth	Distribution Reinforcement	Looping existing 6" ST (FID 500095554) with 8" ST		Y	1	-	-	-	-	800,000	
1666	System Service	Distribution Growth	Station Reinforcement	Station can support current flow but a full rebuild required as per 9S-144 for higher max sustainalbe in future		Y	1	-	-	-	-	107,000	
1667	System Service	Distribution Growth	Station Reinforcement	Changing trim size from 30% to 60% will provide sufficient load for future. Regulators do not have enough differential and it can provide only less than 90% capacity. Higher Inlet will help to get high capacity if possible.		Y	1	-	-	-	-	1,000	
1668	System Service	Distribution Growth	Station Reinforcement	Station has obsolete regulator of 630HP. To support for 380 Max sust and supporting future load, a full rebuild is required with 9S-144		Y	1	-	-	-	-	105,000	
1669	System Service	Distribution Growth	Distribution Reinforcement	Loop existing 6" ST 620kPa from end of 8" (FID 516927203) to Mersea Rd 2 & 2nd Conc Station 03E-		Y	1	-	-	-	-	1,291,198	

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Unique Identifier	Investment Category	Asset/Growth Category	Portfolio	Description	ICM - Eligible	Mandatory	Priority	2019 ($)	2020 ($)	2021 ($)	2022 ($)	2023 ($)	Potential for LTC
				115R									
1709	System Service	Distribution Growth	Distribution Reinforcement	Looping existing 4"ST along Highway 655 with 6" ST. Continuation of 2018 6"ST 6895kPa MOP looping.		Y	1	-	-	602,077	-	-	
1710	System Service	Distribution Growth	Distribution Reinforcement	Looping existing 4"ST upstream of Highway 655 with 6"ST.		Y	1	-	-	-	1,061,000	-	
1994	System Access	Distribution Growth	General Customer Growth	Taylor Mine		Y	1	1,307,000	-	-	-	-	Y
2187	System Access	Distribution Growth	General Customer Growth	Scattered Mains		Y	1	-	14,337,548	14,585,587	14,837,918	15,094,614	
2188	System Access	Distribution Growth	General Customer Growth	Services		Y	1	-	32,780,366	33,347,466	33,924,378	34,511,269	
2189	System Access	Distribution Growth	General Customer Growth	Meter & Reg Installs (Addns - Labour)		Y	1	-	7,985,311	8,123,457	8,263,993	8,406,960	
2190	System Access	Distribution Growth	General Customer Growth	Land Rights		Y	1	-	231,987	236,001	240,083	244,237	
2191	System Access	Distribution Growth	General Customer Growth	Indirect Materials		Y	1	-	1,544,217	1,570,932	1,598,109	1,625,756	
2192	System Access	Distribution Growth	General Customer Growth	Propane Conversion		Y	1	-	2,297	2,337	2,378	2,419	
2193	System Access	Distribution Growth	General Customer Growth	Scattered Other		Y	1	-	48,114	48,946	49,793	50,654	
2308	System Access	Distribution Growth	General Customer Growth	Generic Customer Growth - Rate 20 (North)		Y	1	-	-	-	-	5,000,000	
2353	System Service	Distribution Growth	Hamilton Gate	Hamilton Gate 1	Y	Y	1	-	-	-	20,000,000	-	
2354	System Service	Distribution Growth	Hamilton Gate	Hamilton Gate 2	Y	Y	1	-	-	7,000,000	-	-	
2356	System Access	Distribution Growth	General Customer Growth	Meter & Regulator Additions		Y	1	-	7,510,220	7,758,427	8,120,741	8,388,583	
2359	System Service	Distribution Growth	Distribution Reinforcement	Install 6" PE along west side of 16th Ave tying into 2"		Y	1	-	92,453	-	-	-	
2361	System Service	Distribution Growth	Station Reinforcement	• Replace orifices/regs with 6.4mm • Rebuild relief after isolating valve and replace with 1808A		Y	1	-	4,109	-	-	-	
2363	System Service	Distribution Growth	Station Reinforcement	Reduce outlet P to 335 from 380		Y	1	-	500	-	-	-	
2367	System Service	Distribution Growth	Station Reinforcement	Currently a below-grade vault station, trim change		Y	1	-	500	-	-	-	
2368	System Service	Distribution Growth	Station Reinforcement	Replacing Orifice		Y	1	-	5,500	-	-	-	
2369	System Service	Distribution Growth	Distribution Reinforcement	Looping existing 3" ST (from FID#552724885 to FID#552299258) with 4" ST		Y	1	-	753,858	-	-	-	
2370	System Service	Distribution Growth	Distribution Reinforcement	Connect existing 2" PE (FID 518792595) to existing 4" PE (FID 518792810)		Y	1	-	28,600	-	-	-	
2371	System Service	Distribution Growth	Distribution Reinforcement	Looping existing 3" ST (FID 518847342) with 4" PE		Y	1	-	73,920	-	-	-	
2372	System Service	Distribution Growth	Station Reinforcement	Orifice change to (22.2X15.9) for both Fisher 99 regulators will provide sufficient flow for future load		Y	1	-	500	-	-	-	
2373	System Service	Distribution Growth	Station Reinforcement	Increase Max sustainable back to where it once was. Increase min inlet to accommodate this change.		Y	1	-	8,500	-	-	-	
2374	System Service	Distribution Growth	Transmission Reinforcement	Oxford Phase 2 Reinforcement		Y	1	-	-	20,031	623,559	6,254,716	Y
2375	System Service	Distribution Growth	Transmission Reinforcement	2025 Owen Sound Reinforcement	Y	Y	1	-	-	-	-	140,948	Y
2377	System Service	Distribution Growth	Station Reinforcement	Requires min inlet to be lowered from 620 kPa and over capacity.		Y	1	-	-	255,000	-	-	
2390	System Service	Distribution Growth	Distribution Reinforcement	Sudbury - Install 4" PE through existing 8" casing along Long Lake Rd - PHASE 1		Y	1	-	-	1,100,000	-	-	
2394	System Service	Distribution Growth	Distribution Reinforcement	Sudbury - Install new transmission line along Kingsway from Coniston TBS to Sudbury East. This will be cut down to 420 kPa and support the distribution system. PHASE 1		Y	1	-	-	-	-	1,430,000	
2397	System Service	Distribution Growth	Station Reinforcement	Sudbury Transmission - 2 x 2100 HP Compressor upstream of coniston at Marten River takeoff	Y	Y	1	-	-	-	-	31,200,000	Y
2398	System Service	Distribution Growth	Transmission Reinforcement	Listowel - 1.9km of 6" ST at 1900 kPa MOP. This project in conjuction with the 2024 project will accommodate approximately 5 years' growth on the Listowel lateral starting in 2023		Y	1	-	-	-	-	1,600,000	
2399	System Service	Distribution Growth	Transmission Reinforcement	Cambridge - Lift and lay 1km of 8" 3450 kPa with 1 km of 10" 3450 kPa main.		Y	1	-	-	-	-	1,800,000	

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Unique Identifier	Investment Category	Asset/Growth Category	Portfolio	Description	ICM - Eligible	Mandatory	Priority	2019 ($)	2020 ($)	2021 ($)	2022 ($)	2023 ($)	Potential for LTC
2408	System Service	Distribution Growth	Station Reinforcement	Oxford County - Rebuild both cuts 1A and 2A at Oxford Gate Station for additional flow. See planning for details.		Y	1	-	1,000,000	-	-	-	
2409	System Service	Distribution Growth	Station Reinforcement	Hensall - Require higher outlet pressures out of 14N-302 Hensall Transmission Station to defer reinforcement of the Hensall Trans System by 3 years		Y	1	-	-	-	-	2,000,000	
2900	System Service	Distribution Growth	Distribution Reinforcement	Level Distribution Growth to $11M (Dist & Stations)		Y	1	-	(4,941,650)	(688,093)	4,469,386	(274,045)	
171	General Plant	Fleet	Fleet	OS - Transportation-Replacements		Y	1	10,000,000	-	-	-	-	
938	General Plant	Fleet	Fleet	Fleet Capital purchase		Y	1	-	12,000,000	12,000,000	8,000,000	8,000,000	
840	General Plant	IT	Applications	Contrax Modernization		Y	1	11,465,934	-	-	-	-	
841	General Plant	IT	Applications	Service Suite Lifecycle C/O 2018		Y	1	3,800,000	-	-	-	-	
871	General Plant	IT	Applications	My Account Lifecycle		Y	1	1,000,569	-	-	-	-	
1997	General Plant	IT	Applications	Banner Enhancements		Y	1	1,000,000	-	-	-	-	
1998	General Plant	IT	Applications	Cars Enhancements		Y	1	100,000	-	-	-	-	
1999	General Plant	IT	Applications	EDW Program		Y	1	100,000	-	-	-	-	
2000	General Plant	IT	Applications	GIS Enhancements		Y	1	150,000	-	-	-	-	
2001	General Plant	IT	Applications	GMAS		Y	1	50,000	-	-	-	-	
2002	General Plant	IT	Applications	Interruptions Application Lifecycle		Y	1	100,000	-	-	-	-	
2003	General Plant	IT	Applications	IPCC Enhancements Program		Y	1	75,000	-	-	-	-	
2004	General Plant	IT	Applications	Itron FCS Upgrade		Y	1	25,000	-	-	-	-	
2005	General Plant	IT	Applications	Material Traceability Implementation		Y	1	500,000	-	-	-	-	
2006	General Plant	IT	Applications	New Service Offerings		Y	1	50,000	-	-	-	-	
2007	General Plant	IT	Applications	ProjectWise Upgrade (TRIM)		Y	1	125,000	-	-	-	-	
2008	General Plant	IT	Applications	RiskMaster Upgrade		Y	1	100,000	-	-	-	-	
2009	General Plant	IT	Applications	Sitecore CMS Upgrade 2018		Y	1	100,000	-	-	-	-	
2010	General Plant	IT	Applications	Sitecore CMS Upgrade 2019		Y	1	15,000	-	-	-	-	
2011	General Plant	IT	Applications	Unionline Customer Experience Enhancement Program		Y	1	200,000	-	-	-	-	
2012	General Plant	IT	Applications	WCMS Program		Y	1	100,000	-	-	-	-	
2013	General Plant	IT	Applications	Web Analytics Replacement		Y	1	40,000	-	-	-	-	
2014	General Plant	IT	Applications	SCADA Enhancements/CRM		Y	1	300,000	-	-	-	-	
2015	General Plant	IT	Applications	SCADA Upgrades		Y	1	700,000	-	-	-	-	
2016	General Plant	IT	Hardware	Data/Voice Network Sustainment		Y	1	1,348,000	-	-	-	-	
2017	General Plant	IT	Hardware	Desktop Lifecycle/Sustainment		Y	1	2,294,500	-	-	-	-	
2018	General Plant	IT	Hardware	Plotter Lifecycle		Y	1	50,000	-	-	-	-	
2019	General Plant	IT	Hardware	Server Lifecycle/Sustainment		Y	1	2,607,880	-	-	-	-	
2020	General Plant	IT	IT Technologies	BO Suite Upgrade 2019		Y	1	200,000	-	-	-	-	
2021	General Plant	IT	IT Technologies	CARS Discoverer Migration		Y	1	150,000	-	-	-	-	
2022	General Plant	IT	IT Technologies	FTP Server Lifecycle 2019		Y	1	5,000	-	-	-	-	
2023	General Plant	IT	IT Technologies	Internal Web Environment Lifecycle 2018		Y	1	50,000	-	-	-	-	

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Unique Identifier	Investment Category	Asset/Growth Category	Portfolio	Description	ICM - Eligible	Mandatory	Priority	2019 ($)	2020 ($)	2021 ($)	2022 ($)	2023 ($)	Potential for LTC
2024	General Plant	IT	IT Technologies	Oracle Upgrade 2019		Y	1	200,000	-	-	-	-	
2025	General Plant	IT	IT Technologies	SAP Replication Server Replacement		Y	1	230,000	-	-	-	-	
2026	General Plant	IT	IT Technologies	SQL Server 2018 Upgrade		Y	1	40,000	-	-	-	-	
2027	General Plant	IT	IT Technologies	TFS Upgrade 2019		Y	1	20,000	-	-	-	-	
2028	General Plant	IT	IT Technologies	Windows 10 Application Compatibility Program		Y	1	250,000	-	-	-	-	
2029	General Plant	IT	IT Technologies	Windows Server 2008 Lifecycle Program		Y	1	250,000	-	-	-	-	
2274	General Plant	IT	Applications	Banner		Y	1	-	3,500,000	2,100,000	2,100,000	2,250,000	
2275	General Plant	IT	Applications	CARE		Y	1	-	6,100,000	11,150,000	10,150,000	9,175,000	
2276	General Plant	IT	Applications	CARS		Y	1	-	300,000	7,200,000	7,350,000	7,350,000	
2277	General Plant	IT	Applications	ConTrax		Y	1	-	100,000	350,000	250,000	120,000	
2278	General Plant	IT	Applications	Corrosion		N	3	-	1,500,000	2,000,000	250,000	-	
2279	General Plant	IT	Applications	Customer Interaction Centre		Y	1	-	75,000	75,000	75,000	50,000	
2280	General Plant	IT	Applications	Emergency Service Address Listings		Y	1	-	150,000	-	-	-	
2281	General Plant	IT	Applications	Enterprise Data Warehouse		Y	1	-	200,000	200,000	200,000	200,000	
2282	General Plant	IT	Applications	GIS		N	3	-	1,500,000	750,000	6,000,000	6,000,000	
2283	General Plant	IT	Applications	ProjectWise		Y	1	-	100,000	-	100,000	-	
2284	General Plant	IT	Applications	Service Suite		N	2	-	500,000	1,000,000	500,000	500,000	
2285	General Plant	IT	Applications	Underground Storage Suite		Y	1	-	-	500,000	-	-	
2286	General Plant	IT	Applications	UnionGas.com		Y	1	-	150,000	150,000	215,000	150,000	
2287	General Plant	IT	Applications	UnionLine		Y	1	-	10,000	50,000	25,000	25,000	
2288	General Plant	IT	Applications	SCADA		Y	1	-	1,000,000	1,000,000	1,000,000	1,100,000	
2289	General Plant	IT	Applications	SAP		N	3	-	500,000	250,000	250,000	250,000	
2290	General Plant	IT	Applications	Meters & Measurement		Y	1	-	3,910,000	150,000	550,000	125,000	
2291	General Plant	IT	Applications	Asset Management Program		Y	1	-	1,200,000	450,000	300,000	200,000	
2292	General Plant	IT	Applications	Material Traceability		N	3	-	500,000	750,000	250,000	100,000	
2294	General Plant	IT	Applications	Applications - Other		Y	1	-	1,070,000	630,000	510,000	3,530,000	
2295	General Plant	IT	Applications	Applications - Cloud		Y	1	-	350,000	600,000	850,000	-	
2297	General Plant	IT	Hardware	Hardware - Blanket		Y	1	-	4,385,625	4,359,857	4,560,650	5,386,481	
2298	General Plant	IT	Hardware	Corrosion		Y	1	-	-	275,000	-	-	
2299	General Plant	IT	Hardware	Customer Interaction Centre		Y	1	-	-	-	100,000	450,000	
2300	General Plant	IT	Hardware	GIS		Y	1	-	-	50,000	-	60,000	
2302	General Plant	IT	Hardware	STO Smartphones / Lone Worker		Y	1	-	-	275,000	-	-	
2303	General Plant	IT	Hardware	USR Smartphones		Y	1	-	300,000	-	-	325,000	
2304	General Plant	IT	Hardware	USR Toughbooks		Y	1	-	2,750,000	-	-	-	
2305	General Plant	IT	Hardware	Meters & Measurement		Y	1	-	-	1,425,000	-	115,000	
2306	General Plant	IT	IT Technologies	IT Technologies - Blanket		Y	1	-	1,105,000	1,350,000	1,115,000	1,260,000	

Project Listing for UGL (2019-2023)

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400	General Plant	LNG	Tools	STO CAPITAL TOOLS ADDITIONS - HAGAR LNG		N	2	22,258	-	-	-	-	
401	General Plant	LNG	Tools	STO CAPITAL TOOLS REPL - HAGAR LNG		N	2	22,258	-	-	-	-	
1035	System Renewal	LNG	LNG - Possible Large Projects	KVGR and Cycle Mix Cooler		N	3	-	-	-	6,242,400	-	
1042	System Renewal	LNG	LNG Capital Maintenance	L10 Liquid Nitrogen Upgrades		Y	1	-	21,224	-	-	-	
1545	System Renewal	LNG	Compressor and Dehy Capital Maintenance	STO IROQUOIS FALLS VIBRATION MONITOR		N	3	-	-	-	-	80,010	
24	General Plant	Measurement	Measurement Electronics Upgrades	ENG - LAB FACILITIES UPGRADE		Y	1	70,000	-	-	-	-	
30	System Service	Measurement	Odourant Upgrades	ENG - Odourant Upgrade		Y	1	1,024,932	-	-	-	-	
42	System Renewal	Measurement	Obsolete RTU Equipment	ENG -Bristol 3330 Replacement Program		N	3	1,364,775	-	-	-	-	
52	General Plant	Measurement	Tools	ENG -Technician Tools Additions		N	2	50,000	-	-	-	-	
54	System Service	Measurement	Measurement Electronics Upgrades	ENG -Turbine Meter Automatic Oilers		N	2	34,340	-	-	-	-	
56	System Renewal	Measurement	Labour Cost for exchanges (maint.)	Meter & Regulator Inst Repl-Company		Y	1	621,478	-	-	-	-	
60	System Renewal	Measurement	Labour Cost for exchanges (maint.)	Meter & Regulator Inst Repl-Company		Y	1	589,447	-	-	-	-	
66	System Renewal	Measurement	Labour Cost for exchanges (maint.)	Meter & Regulator Inst Repl-Company		Y	1	1,855,576	-	-	-	-	
72	System Renewal	Measurement	Labour Cost for exchanges (maint.)	Meter & Regulator Inst Repl-Company		Y	1	432,005	-	-	-	-	
78	System Renewal	Measurement	Labour Cost for exchanges (maint.)	Meter & Regulator Inst Repl-Company		Y	1	1,183,758	-	-	-	-	
82	System Renewal	Measurement	Labour Cost for exchanges (maint.)	Meter & Regulator Inst Repl-Company		Y	1	630,579	-	-	-	-	
92	System Renewal	Measurement	Labour Cost for exchanges (maint.)	Meter & Regulator Inst Repl-Company		Y	1	614,849	-	-	-	-	
99	System Renewal	Measurement	Labour Cost for exchanges (maint.)	Meter & Regulator Inst Repl-Company		Y	1	1,175,826	-	-	-	-	
108	System Renewal	Measurement	Labour Cost for exchanges (maint.)	Meter & Regulator Inst Repl-Company		Y	1	746,090	-	-	-	-	
121	System Renewal	Measurement	Labour Cost for exchanges (maint.)	Meter & Regulator Inst Repl-Company		Y	1	825,808	-	-	-	-	
129	System Renewal	Measurement	Labour Cost for exchanges (maint.)	Meter & Regulator Inst Repl-Company		Y	1	401,781	-	-	-	-	
139	System Renewal	Measurement	Labour Cost for exchanges (maint.)	Meter & Regulator Inst Repl-Company		Y	1	578,631	-	-	-	-	
176	System Renewal	Measurement	Labour Cost for exchanges (maint.)	Meter & Regulator Inst Repl-Contractor		Y	1	605,965	-	-	-	-	
178	System Renewal	Measurement	Labour Cost for exchanges (maint.)	Meter & Regulator Inst Repl-Contractor		Y	1	1,291,973	-	-	-	-	
180	System Renewal	Measurement	Labour Cost for exchanges (maint.)	Meter & Regulator Inst Repl-Contractor		Y	1	261,594	-	-	-	-	
384	System Renewal	Measurement	Labour Cost for exchanges (maint.)	Meter & Regulator Inst Repl-Contractor		Y	1	707,274	-	-	-	-	
386	System Renewal	Measurement	Labour Cost for exchanges (maint.)	Meter & Regulator Inst Repl-Contractor		Y	1	1,029,519	-	-	-	-	
388	System Renewal	Measurement	Labour Cost for exchanges (maint.)	Meter & Regulator Inst Repl-Contractor		Y	1	1,053,787	-	-	-	-	
491	System Renewal	Measurement	Meter Exchange Program	SMC-Meter & Regulator Replacements North		Y	1	5,541,546	-	-	-	-	
620	System Renewal	Measurement	Meter Exchange Program	SMC-Meter & Regulator Replacements South		Y	1	14,672,477	-	-	-	-	
925	System Renewal	Measurement	Measurement Electronics Upgrades	Billing Communication - lifecycle		N	3	-	102,000	102,000	102,000	102,000	
926	General Plant	Measurement	Tools	Electronic Technician Tools		N	2	-	50,000	50,000	50,000	50,000	
927	System Renewal	Measurement	Meter Exchange Program	Gas Meters and Devices - Plant Item Costs		Y	1	-	15,593,827	15,879,514	16,084,744	16,773,539	
929	General Plant	Measurement	Measurement Electronics Upgrades	Lab Upgrades		Y	1	-	70,000	70,000	70,000	70,000	
930	System Renewal	Measurement	Meter Exchange Program	Labour Cost for exchanges (maint.)		Y	1	-	14,561,450	14,681,955	14,681,955	15,048,875	
932	System Renewal	Measurement	Measurement Electronics Upgrades	Measurement replacement at low flow odorant sites		Y	1	-	51,000	102,000	102,000	102,000	

Project Listing for UGL (2019-2023)

Unique Identifier	Investment Category	Asset/Growth Category	Portfolio	Description	ICM - Eligible	Mandatory	Priority	2019 ($)	2020 ($)	2021 ($)	2022 ($)	2023 ($)	Potential for LTC
933	System Service	Measurement	Odourant Upgrades	Odourant Upgrade		Y	1	-	1,428,000	1,020,000	1,020,000	1,020,000	
934	System Renewal	Measurement	Obsolete RTU Equipment	Replacement of Obsolete RTUs		N	3	-	3,050,000	3,050,000	2,540,000	2,030,000	
32	Overheads	Overheads	Overheads	3rd Party Pre-Work		Y	1	323,360	-	-	-	-	
49	Overheads	Overheads	Overheads	3rd Party Pre-Work		Y	1	275,000	-	-	-	-	
61	Overheads	Overheads	Overheads	3rd Party Pre-Work		Y	1	260,580	-	-	-	-	
73	Overheads	Overheads	Overheads	3rd Party Pre-Work		Y	1	400,000	-	-	-	-	
94	Overheads	Overheads	Overheads	3rd Party Pre-Work		Y	1	50,000	-	-	-	-	
109	Overheads	Overheads	Overheads	3rd Party Pre-Work		Y	1	120,000	-	-	-	-	
141	Overheads	Overheads	Overheads	3rd Party Pre-Work		Y	1	50,000	-	-	-	-	
170	Overheads	Overheads	Overheads	2019 Contractor Fixed Overhead-STIP		Y	1	1,268,680	-	-	-	-	
201	Overheads	Overheads	Overheads	O&M Capitalized for OEB		Y	1	59,234,618	-	-	-	-	
831	Overheads	Overheads	Overheads	3rd Party Pre-Work - New Business		Y	1	127,786	-	-	-	-	
832	Overheads	Overheads	Overheads	3rd Party Pre-Work - New Business		Y	1	325,000	-	-	-	-	
833	Overheads	Overheads	Overheads	3rd Party Pre-Work - New Business		Y	1	200,000	-	-	-	-	
834	Overheads	Overheads	Overheads	3rd Party Pre-Work - New Business		Y	1	100,000	-	-	-	-	
835	Overheads	Overheads	Overheads	3rd Party Pre-Work - New Business		Y	1	100,000	-	-	-	-	
836	Overheads	Overheads	Overheads	3rd Party Pre-Work - New Business		Y	1	30,000	-	-	-	-	
837	Overheads	Overheads	Overheads	3rd Party Pre-Work - New Business		Y	1	60,000	-	-	-	-	
1193	Overheads	Overheads	Overheads	Overheads		Y	1	-	49,264,138	58,291,176	71,367,050	60,613,858	
1564	Overheads	Overheads	Overheads	ICM Capitalized OH	Y	Y	1	19,100,492	-	-	-	-	
2357	Overheads	Overheads	Overheads	Overheads Allocation ICM	Y	Y	1	-	30,735,862	21,708,824	8,632,950	19,386,142	
1	System Service	Pipelines	Other	King- Isolation Valves - District - Inst		Y	1	124,955	-	-	-	-	
5	System Access	Pipelines	Municipal Replacement	Plan-(B)-Dist-Repl-Contr-Mains Municipal		Y	1	1,549,799	-	-	-	-	
7	System Access	Pipelines	Municipal Replacement	Plan-(B)-Dist-Repl-Contr-Mains Municipal		Y	1	6,201,817	-	-	-	-	
9	System Access	Pipelines	Municipal Replacement	Plan-(B)-Dist-Repl-Compy-Mains Municipal		Y	1	120,995	-	-	-	-	
11	System Access	Pipelines	Municipal Replacement	Plan-(B)-Dist-Repl-Compy-Mains Municipal		Y	1	104,473	-	-	-	-	
14	General Plant	Pipelines	Other	Indirect Materials-Replacements		Y	1	51,841	-	-	-	-	
17	General Plant	Pipelines	Other	Indirect Materials-Replacements		Y	1	46,038	-	-	-	-	
18	System Renewal	Pipelines	Other	NW_Lateral Clamp Cut Outs_ATIKOKAN		Y	1	-	-	-	2,400,000	-	
28	System Access	Pipelines	Municipal Replacement	Plan-(B)-Dist-Repl-Contr-Mains Municipal		Y	1	3,147,110	-	-	-	-	
31	General Plant	Pipelines	Other	Indirect Materials-Replacements		Y	1	125,569	-	-	-	-	
33	System Renewal	Pipelines	Anodes	ANODES		Y	1	1,147,503	-	-	-	-	
37	System Access	Pipelines	Municipal Replacement	Plan-(B)-Dist-Repl-Contr-Mains Municipal		Y	1	226,828	-	-	-	-	
39	General Plant	Pipelines	Other	Indirect Materials-Replacements		Y	1	22,671	-	-	-	-	
40	System Access	Pipelines	Municipal Replacement	Vidal St Municipal		Y	1	800,000	-	-	-	-	
46	System Access	Pipelines	Municipal Replacement	Plan-(B)-Dist-Repl-Contr-Mains Municipal		Y	1	2,670,650	-	-	-	-	

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Unique Identifier	Investment Category	Asset/Growth Category	Portfolio	Description	ICM - Eligible	Mandatory	Priority	2019 ($)	2020 ($)	2021 ($)	2022 ($)	2023 ($)	Potential for LTC
50	System Renewal	Pipelines	Anodes	ANODES		Y	1	593,415	-	-	-	-	
62	System Renewal	Pipelines	Anodes	ANODES		Y	1	997,375	-	-	-	-	
69	System Access	Pipelines	Municipal Replacement	Plan-(B)-Dist-Repl-Contr-Mains Municipal		Y	1	4,149,144	-	-	-	-	
70	General Plant	Pipelines	Land Rights	Land Rights-Replacements		Y	1	15,000	-	-	-	-	
74	System Renewal	Pipelines	Anodes	ANODES		Y	1	1,662,019	-	-	-	-	
79	System Access	Pipelines	Municipal Replacement	Plan-(B)-Dist-Repl-Contr-Mains Municipal		Y	1	1,804,307	-	-	-	-	
80	General Plant	Pipelines	Land Rights	Land Rights-Replacements		Y	1	15,000	-	-	-	-	
90	System Renewal	Pipelines	Other	King- Casing Upgrade District various -		Y	1	100,643	-	-	-	-	
91	System Access	Pipelines	Municipal Replacement	Plan-(B)-Dist-Repl-Compy-Mains Municipal		Y	1	651,285	-	-	-	-	
93	General Plant	Pipelines	Other	Indirect Materials-Replacements		Y	1	55,645	-	-	-	-	
95	System Renewal	Pipelines	Anodes	ANODES		Y	1	525,486	-	-	-	-	
96	System Renewal	Pipelines	Cathodic Protection Advancements	King- Sectionalization Various -District		Y	1	163,127	-	-	-	-	
107	General Plant	Pipelines	Land Rights	Land Rights-Replacements		Y	1	10,200	-	-	-	-	
110	System Renewal	Pipelines	Anodes	ANODES		Y	1	589,781	-	-	-	-	
111	System Renewal	Pipelines	Cathodic Protection Advancements	Northwest 2019 Sectionalization		Y	1	412,721	81,600	81,600	81,600	-	
119	System Access	Pipelines	Municipal Replacement	Plan-(B)-Dist-Repl-Contr-Mains Municipal		Y	1	181,905	-	-	-	-	
120	General Plant	Pipelines	Land Rights	Land Rights-Replacements		Y	1	12,500	-	-	-	-	
122	General Plant	Pipelines	Other	Misc Materials-Company		Y	1	5,565	-	-	-	-	
123	System Renewal	Pipelines	Anodes	Anodes		Y	1	299,162	-	-	-	-	
124	System Renewal	Pipelines	Cathodic Protection Advancements	Sudbury/SSmarie Sectionalization		Y	1	96,431	100,000	100,000	100,000	-	
128	General Plant	Pipelines	Land Rights	Land Rights-Replacements		Y	1	10,200	-	-	-	-	
137	System Access	Pipelines	Municipal Replacement	Plan-(B)-Dist-Repl-Contr-Mains Municipal		Y	1	181,905	-	-	-	-	
138	General Plant	Pipelines	Land Rights	Land Rights-Replacements		Y	1	12,500	-	-	-	-	
142	System Renewal	Pipelines	Anodes	Anodes		Y	1	433,126	-	-	-	-	
143	System Renewal	Pipelines	Cathodic Protection Advancements	North Bay/Orillia Sectionalization		Y	1	382,326	108,000	108,000	108,000	-	
173	System Service	Pipelines	Class Location	Class Location Change Progam		Y	1	20,350,417	-	-	-	-	
175	System Renewal	Pipelines	Integrity Management Program	ENG - Integrity Management Program		Y	1	14,642,739	-	-	-	-	
182	System Renewal	Pipelines	Bruce Lake	Bruce Lake Lateral - c/o 2018		N	3	9,500,000	-	-	-	-	
212	System Renewal	Pipelines	Windsor Line	Windsor Line Ph 1	Y	N	2	3,000,000	-	-	-	-	Y
220	System Renewal	Pipelines	London Lines	LOND-London Lines	Y	N	3	-	4,000,000	107,000,000	3,000,000	-	Y
236	General Plant	Pipelines	Tools	Capital Tools- Additions-Dist Ops		N	2	60,892	-	-	-	-	
237	General Plant	Pipelines	Tools	Capital Tools- Repl- Dist Ops		N	2	44,698	-	-	-	-	
240	General Plant	Pipelines	Tools	Capital Tools-Additions-Dist Ops		N	2	19,339	-	-	-	-	
241	General Plant	Pipelines	Tools	Capital Tools-Repl-Dist Ops		N	2	26,782	-	-	-	-	
244	General Plant	Pipelines	Tools	Capital Tools- Additions-Dist Ops		N	2	150,000	-	-	-	-	
245	General Plant	Pipelines	Tools	Capital Tools- Repl- Dist Ops		N	2	110,000	-	-	-	-	

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251	System Renewal	Pipelines	Leakage	Plan-(B)-Dist-Repl-Contr-Mains Leakage		N	3	499,984	-	-	-	-	
252	System Renewal	Pipelines	Service Replacement	Plan-(B)-Dist-Repl-Contr-Services		N	3	285,256	-	-	-	-	
254	System Renewal	Pipelines	General Mains	Plan-(B)-Dist-Repl-General Mains		N	3	253,468	-	-	-	-	
255	System Renewal	Pipelines	Service Replacement	Plan-(B)-Dist-Repl-Compy-Services		N	3	522,571	-	-	-	-	
260	System Renewal	Pipelines	Leakage	Plan-(B)-Dist-Repl-Contr-Mains Leakage		N	3	70,917	-	-	-	-	
261	System Renewal	Pipelines	Service Replacement	Plan-(B)-Dist-Repl-Contr-Services		N	3	61,621	-	-	-	-	
262	System Renewal	Pipelines	General Mains	Plan-(B)-Dist-Repl-General Mains		N	3	40,317	-	-	-	-	
263	System Renewal	Pipelines	Service Replacement	Plan-(B)-Dist-Repl-Compy-Services		N	3	49,751	-	-	-	-	
266	System Renewal	Pipelines	Service Replacement	Plan-(B)-Dist-Repl-Contr-Services		N	3	71,545	-	-	-	-	
267	System Renewal	Pipelines	Service Replacement	Plan-(B)-Dist-Repl-Compy-Services		N	3	94,800	-	-	-	-	
276	System Renewal	Pipelines	Leakage	Plan-(B)-Dist-Repl-Contr-Mains Leakage		N	3	299,100	-	-	-	-	
277	System Renewal	Pipelines	Service Replacement	Plan-(B)-Dist-Repl-Contr-Services		N	3	71,545	-	-	-	-	
278	System Renewal	Pipelines	General Mains	Plan-(B)-Dist-Repl-Contr-Other-Scattered		N	3	253,203	-	-	-	-	
280	System Renewal	Pipelines	General Mains	Plan-(B)-Dist-Repl-General Mains		N	3	125,293	-	-	-	-	
281	System Renewal	Pipelines	Service Replacement	Plan-(B)-Dist-Repl-Compy-Services		N	3	224,472	-	-	-	-	
282	General Plant	Pipelines	Tools	Capital Tools-Additions-Dist Ops		N	2	79,000	-	-	-	-	
283	General Plant	Pipelines	Tools	Capital Tools-Repl-Dist Ops		N	2	106,000	-	-	-	-	
286	System Renewal	Pipelines	Leakage	Plan-(B)-Dist-Repl-Contr-Mains Leakage		N	3	199,970	-	-	-	-	
287	System Renewal	Pipelines	Service Replacement	Plan-(B)-Dist-Repl-Contr-Services		N	3	107,849	-	-	-	-	
294	System Renewal	Pipelines	Service Replacement	Plan-(B)-Dist-Repl-Contr-Services		N	3	339,725	-	-	-	-	
295	System Renewal	Pipelines	General Mains	Plan-(B)-Dist-Repl-Contr-Other-Scattered		N	3	199,905	-	-	-	-	
297	System Renewal	Pipelines	General Mains	Plan-(B)-Dist-Repl-General Mains		N	3	199,959	-	-	-	-	
298	General Plant	Pipelines	Tools	Capital Tools-Additions-Dist Ops		N	2	50,000	-	-	-	-	
299	General Plant	Pipelines	Tools	Capital Tools-Repl-Dist Ops		N	2	110,000	-	-	-	-	
307	System Renewal	Pipelines	Leakage	Plan-(B)-Dist-Repl-Contr-Mains Leakage		N	3	587,656	-	-	-	-	
308	System Renewal	Pipelines	Service Replacement	Plan-(B)-Dist-Repl-Contr-Services		N	3	378,842	-	-	-	-	
310	System Renewal	Pipelines	General Mains	Plan-(B)-Dist-Repl-General Mains		N	3	239,224	-	-	-	-	
311	System Renewal	Pipelines	Service Replacement	Plan-(B)-Dist-Repl-Compy-Services		N	3	271,937	-	-	-	-	
312	General Plant	Pipelines	Tools	Capital Tools-Additions-Dist Ops		N	2	27,000	-	-	-	-	
313	General Plant	Pipelines	Tools	Capital Tools-Repl-Dist Ops		N	2	131,750	-	-	-	-	
319	System Renewal	Pipelines	Leakage	Plan-(B)-Dist-Repl-Contr-Mains Leakage		N	3	180,310	-	-	-	-	
320	System Renewal	Pipelines	Service Replacement	Plan-(B)-Dist-Repl-Contr-Services		N	3	683,869	-	-	-	-	
322	System Renewal	Pipelines	General Mains	Plan-(B)-Dist-Repl-General Mains		N	3	358,761	-	-	-	-	
323	System Renewal	Pipelines	Service Replacement	Plan-(B)-Dist-Repl-Compy-Services		N	3	236,085	-	-	-	-	
329	System Renewal	Pipelines	Service Replacement	Plan-(B)-Dist-Repl-Compy-Services		N	3	309,402	-	-	-	-	
330	General Plant	Pipelines	Tools	Capital Tools Add-Eastern Dist		N	2	121,000	-	-	-	-	

Project Listing for UGL (2019-2023)

Unique Identifier	Investment Category	Asset/Growth Category	Portfolio	Description	ICM - Eligible	Mandatory	Priority	2019 ($)	2020 ($)	2021 ($)	2022 ($)	2023 ($)	Potential for LTC
331	General Plant	Pipelines	Tools	Capital Tools-Repl-Eastern District		N	2	50,000	-	-	-	-	
334	General Plant	Pipelines	Tools	Capital Tools-Adds-Dist Ops		N	2	101,439	-	-	-	-	
335	General Plant	Pipelines	Tools	Capital Tools-Repl-Dist Ops		N	2	101,439	-	-	-	-	
343	System Renewal	Pipelines	Leakage	Plan-(B)-Dist-Repl-Contr-Mains Leakage		N	3	137,190	-	-	-	-	
344	System Renewal	Pipelines	Service Replacement	Plan-(B)-Dist-Repl-Contr-Services		N	3	48,725	-	-	-	-	
346	System Renewal	Pipelines	General Mains	Plan-(B)-Dist-Gen Mains		N	3	186,320	-	-	-	-	
347	System Renewal	Pipelines	Service Replacement	Plan-(B)-Dist-Repl-Comp-Services		N	3	141,577	-	-	-	-	
348	General Plant	Pipelines	Tools	Capital Tools-Adds-Dist Ops		N	2	43,500	-	-	-	-	
349	General Plant	Pipelines	Tools	Capital Tools-Repl-Dist Ops		N	2	51,500	-	-	-	-	
357	System Renewal	Pipelines	Leakage	Plan-(B)-Dist-Repl-Contr-Mains Leakage		N	3	137,190	-	-	-	-	
358	System Renewal	Pipelines	Service Replacement	Plan-(B)-Dist-Repl-Contr-Services		N	3	48,725	-	-	-	-	
360	System Renewal	Pipelines	General Mains	Plan-(B)-Dist-Gen Mains		N	3	186,320	-	-	-	-	
361	System Renewal	Pipelines	Service Replacement	Plan-(B)-Dist-Repl-Comp-Services		N	3	141,577	-	-	-	-	
362	General Plant	Pipelines	Tools	Capital Tools-Adds-Dist Ops		N	2	43,500	-	-	-	-	
363	General Plant	Pipelines	Tools	Capital Tools-Repl-Dist Ops		N	2	51,500	-	-	-	-	
374	General Plant	Pipelines	Tools	STO CAPITAL TOOLS REPL - S&T		N	2	22,258	-	-	-	-	
375	General Plant	Pipelines	Tools	STO CAPITAL TOOLS ADDITIONS - S&T		N	2	22,258	-	-	-	-	
378	General Plant	Pipelines	Tools	Tech Training - Tools Addition		N	2	25,000	-	-	-	-	
379	General Plant	Pipelines	Tools	Tech Training - Tools Replacement		N	2	25,000	-	-	-	-	
381	General Plant	Pipelines	Tools	Tools Corrosion Engineering		N	2	50,000	-	-	-	-	
389	General Plant	Pipelines	Other	Misc Materials-Company		Y	1	5,565	-	-	-	-	
396	System Renewal	Pipelines	Leakage	Plan-(B)-Dist-Repl-Compy-Mains Leakage		N	3	41,678	-	-	-	-	
397	System Renewal	Pipelines	Service Replacement	Plan-(B)-Dist-Repl-Compy-Services		N	3	139,343	-	-	-	-	
398	System Renewal	Pipelines	Leakage	Plan-(B)-Dist-Repl-Compy-Mains Leakage		N	3	41,678	-	-	-	-	
399	System Renewal	Pipelines	Service Replacement	Plan-(B)-Dist-Repl-Compy-Services		N	3	68,844	-	-	-	-	
405	System Renewal	Pipelines	Leakage - Discreet	WIND-Tecumseh Rd E Leakage Ph1-Windsor		N	3	-	-	1,351,687	-	-	
406	System Renewal	Pipelines	Other	WIND_Meresea Rd 2 Ph1 Repl_Leamington		N	3	-	1,368,481	-	-	-	
408	System Renewal	Pipelines	Leakage - Discreet	Oak St. Ph 2		N	3	-	-	895,839	-	-	
410	System Renewal	Pipelines	Leakage - Discreet	WIND-Tecumseh Rd E Leakage Ph2-Windsor		N	3	-	1,384,975	-	-	-	
414	System Renewal	Pipelines	Other	WIND_Tuscarora & McDougall Repl_Windsor		N	3	-	647,795	-	-	-	
415	System Renewal	Pipelines	Leakage - Discreet	Mersea Rd 2 Ph 2		N	3	-	-	589,009	842,228	-	
418	System Renewal	Pipelines	Other	CHAT-Jane Rd Repl-Zone Twp		N	3	-	142,330	-	-	-	
420	System Renewal	Pipelines	Bare and Unprotected steel	SARN:Christina&Lakeshore Leakeage-Sarnia		N	2	1,181,616	-	-	-	-	
428	System Renewal	Pipelines	Bare and Unprotected steel	LOND: Mt Brydges B Leakage		N	2	697,902	-	-	-	-	
437	System Renewal	Pipelines	Bare and Unprotected steel	LOND: Thompson Rd Leakage- London		N	2	400,000	-	-	-	-	
439	System Renewal	Pipelines	Bare and Unprotected steel	LOND: Short & Fairhaven Leakage-London		N	2	400,000	-	-	-	-	

Project Listing for UGL (2019-2023)

Unique Identifier	Investment Category	Asset/Growth Category	Portfolio	Description	ICM - Eligible	Mandatory	Priority	2019 ($)	2020 ($)	2021 ($)	2022 ($)	2023 ($)	Potential for LTC
445	System Renewal	Pipelines	Bare and Unprotected steel	HAMI-FiddlersGreenRdLeakage-Ancaster		N	2	748,819	-	-	-	-	
448	System Renewal	Pipelines	Other	HAMI-Hwy6NPS10Replacement-Caledonia		N	3	-	2,005,396	-	-	-	Y
458	System Renewal	Pipelines	Other	REPL Crowe River Crossing		N	3	-	596,084	-	-	-	
459	System Renewal	Pipelines	Other	REPL Bath and Days Rd		N	2	329,941	-	-	-	-	
464	System Renewal	Pipelines	Emo Sched 10	Schedule 10 Replacement Emo		N	3	2,821,046	-	-	-	-	
466	System Service	Pipelines	Depth of Cover <30% SMYS	NW_Centennial 8" Exposed_TBAY		N	3	-	550,564	-	-	-	
467	System Service	Pipelines	Other	Northwest Valve Installations		N	3	-	172,669	-	-	-	
472	System Renewal	Pipelines	Bridge Crossings	North Bay-Lamorie Bridge Repl		N	3	-	396,253	-	-	-	
505	System Renewal	Pipelines	Bare and Unprotected steel	WIND_East Ruscom River Repl_Lakeshore		N	2	144,087	-	-	-	-	
512	System Renewal	Pipelines	Other	WIND_Chatham St Repl_Windsor		N	3	-	134,887	-	-	-	
514	System Renewal	Pipelines	Water Crossings	CHAT_Fourteenth Line Repl_Raleigh		N	3	-	35,092	-	-	-	
527	System Renewal	Pipelines	Bare and Unprotected steel	BRAN-Lierman Dam Rd & Old Mill Rd Leakag		N	2	668,808	-	-	-	-	
528	System Renewal	Pipelines	Bare and Unprotected steel	BRAN-Hewitt Rd Leakage Repl BU-Vittoria		N	2	88,000	-	-	-	-	
529	System Renewal	Pipelines	Bare and Unprotected steel	BRAN-Talbot & Big Creek Rd Leak BU Delhi		N	2	105,000	-	-	-	-	
533	System Renewal	Pipelines	Bridge Crossings	WAT-Weber St N Bridge Crossing Repl,Wloo		N	3	-	-	450,000	-	-	
555	System Renewal	Pipelines	Bare and Unprotected steel	WAT-Church St S Repl (Vine to Moore)		N	2	84,000	-	-	-	-	
565	System Renewal	Pipelines	Pipeline Integrity > 30% SMYS	NPS36 Valve Oper Repl, Beachville		N	3	-	108,268	-	-	-	
569	System Renewal	Pipelines	Other	King- Ingredian -Cardinal - Remove exist		N	3	-	-	-	614,058	-	
581	System Renewal	Pipelines	Cathodic Protection Advancements	North Bay/Orillia Rectifiers		Y	1	154,131	-	-	-	-	
611	System Renewal	Pipelines	Cathodic Protection Advancements	Walker Rd Repl.		Y	1	58,977	-	-	-	-	
617	System Renewal	Pipelines	Cathodic Protection Advancements	Sudbury/SSmarie Rectifiers		Y	1	148,033	-	-	-	-	
890	System Renewal	Pipelines	Anodes	anodes		Y	1	-	6,400,000	6,400,000	6,400,000	6,400,000	
897	System Service	Pipelines	Class Location	Class Location		Y	1	-	20,000,000	20,000,000	15,000,000	15,000,000	
898	General Plant	Pipelines	Tools	DO Tools		N	2	-	1,300,000	1,300,000	1,300,000	1,300,000	
900	System Renewal	Pipelines	General Mains	General Mains		N	2	-	3,364,046	3,364,046	3,364,046	3,364,046	
902	System Renewal	Pipelines	Integrity Management Program	Integrity Management Program		Y	1	-	14,065,000	13,865,000	12,907,000	12,350,000	
903	System Renewal	Pipelines	Leakage	Leakage		N	2	-	4,268,934	4,268,934	4,268,934	4,268,934	
906	System Service	Pipelines	MOP Verification	MOP Verification		Y	1	-	-	-	-	5,000,000	
907	System Access	Pipelines	Municipal Replacement	Municipal Replacement		Y	1	-	24,000,000	24,000,000	24,000,000	24,000,000	
910	System Renewal	Pipelines	Service Replacement	Service Replacement		Y	1	-	4,429,166	4,505,790	4,583,741	4,663,039	
913	System Renewal	Pipelines	Windsor Line	Windsor Line	Y	N	3	-	83,000,000	2,000,000	-	-	Y
1204	System Renewal	Pipelines	Bare and Unprotected steel	LOND: Tecumseh & Edward - London		N	2	-	270,504	-	-	-	
1205	System Renewal	Pipelines	Bare and Unprotected steel	LOND: Hamilton & Hydro - London		N	2	464,000	-	-	-	-	
1206	System Renewal	Pipelines	Bare and Unprotected steel	LOND: Talbot Line - Talbotville		N	2	-	124,848	-	-	-	
1207	System Renewal	Pipelines	Bare and Unprotected steel	LOND: St George & Talbot - St Thomas		N	2	-	52,020	-	-	-	
1208	System Renewal	Pipelines	Bare and Unprotected steel	WAT-Scott St-Windham		N	2	-	199,293	-	-	-	

Project Listing for UGL (2019-2023)

Unique Identifier	Investment Category	Asset/Growth Category	Portfolio	Description	ICM - Eligible	Mandatory	Priority	2019 ($)	2020 ($)	2021 ($)	2022 ($)	2023 ($)	Potential for LTC
1209	System Renewal	Pipelines	Bare and Unprotected steel	WIND-Riverside from Arlington to Kensington Replacement		N	2	-	396,913	-	-	-	
1210	System Renewal	Pipelines	Bare and Unprotected steel	LOND: Hale & Dundas - London		N	2	-	62,424	-	-	-	
1211	System Renewal	Pipelines	Bare and Unprotected steel	LOND: Ashland & Brydges		N	2	-	124,848	-	-	-	
1212	System Renewal	Pipelines	Bare and Unprotected steel	LOND: Hickson & Belgrave		N	2	-	72,828	-	-	-	
1213	System Renewal	Pipelines	Bare and Unprotected steel	LOND: Little Hill & Hamilton		N	2	-	124,848	-	-	-	
1214	System Renewal	Pipelines	Bare and Unprotected steel	LOND: Lovett & Rectory		N	2	-	62,424	-	-	-	
1215	System Renewal	Pipelines	Bare and Unprotected steel	LOND: Brisbin & Hamilton		N	2	-	312,120	-	-	-	
1216	System Renewal	Pipelines	Bare and Unprotected steel	LOND: Hydro & Hamilton		N	2	-	187,272	-	-	-	
1217	System Renewal	Pipelines	Bare and Unprotected steel	LOND: Vauxhall & Egerton		N	2	-	124,848	-	-	-	
1218	System Renewal	Pipelines	Bare and Unprotected steel	SARN: Lynwood & Elmhurst - Sarnia		N	2	-	243,454	-	-	-	
1219	System Renewal	Pipelines	Bare and Unprotected steel	SARN: Lakeshore C - Sarnia		N	2	-	728,280	-	-	-	
1220	System Renewal	Pipelines	Bare and Unprotected steel	HAMI-Kerr-Oakville		N	2	-	676,260	-	-	-	
1221	System Renewal	Pipelines	Bare and Unprotected steel	WAT-Peel-Delhi		N	2	-	556,449	-	-	-	
1222	System Renewal	Pipelines	Bare and Unprotected steel	WAT- Bay 1 - Port Rowan		N	2	-	76,467	-	-	-	
1223	System Renewal	Pipelines	Bare and Unprotected steel	WAT-Catherine - Port Rowan		N	2	-	45,960	-	-	-	
1224	System Renewal	Pipelines	Bare and Unprotected steel	WAT-Croton - Delhi		N	2	-	832,320	-	-	-	
1225	System Renewal	Pipelines	Bare and Unprotected steel	WAT-Dalton- Delhi		N	2	-	495,230	-	-	-	
1227	System Renewal	Pipelines	Bare and Unprotected steel	WIND-Maidstone & Talbot Replacement		N	2	-	204,126	-	-	-	
1228	System Renewal	Pipelines	Bare and Unprotected steel	WIND-Arthur & Talbot Replacement		N	2	-	39,691	-	-	-	
1229	System Renewal	Pipelines	Bare and Unprotected steel	WIND- Laird from Alice to Victor Replacement		N	2	-	453,614	-	-	-	
1230	System Renewal	Pipelines	Bare and Unprotected steel	WIND-Lacasse from St Denis to Tecumseh Rd E Replacement		N	2	-	113,404	-	-	-	
1231	System Renewal	Pipelines	Bare and Unprotected steel	LOND:St Julien & Tommy Hunter		N	2	-	31,212	-	-	-	
1232	System Renewal	Pipelines	Bare and Unprotected steel	LOND: Jellicoe & Blake		N	2	-	239,292	-	-	-	
1233	System Renewal	Pipelines	Bare and Unprotected steel	SARN: Woodrow & Egmond		N	2	-	718,916	-	-	-	
1234	System Renewal	Pipelines	Bare and Unprotected steel	SARN: O'dell & Colborne		N	2	-	143,575	-	-	-	
1235	System Renewal	Pipelines	Bare and Unprotected steel	HAMI-John St - Hagersville		N	2	-	148,777	-	-	-	
1236	System Renewal	Pipelines	Bare and Unprotected steel	HAMI-Haldimand Trail - Dunn		N	2	-	338,130	-	-	-	
1237	System Renewal	Pipelines	Bare and Unprotected steel	WAT- Archibald		N	2	-	111,037	-	-	-	
1238	System Renewal	Pipelines	Bare and Unprotected steel	WIND-Hagerty & Amy (Thames River) Aeriel Crossing Replacement		N	2	-	136,084	-	-	-	
1239	System Renewal	Pipelines	Bare and Unprotected steel	HAMI- HWY 6 Seneca		N	2	-	208,080	-	-	-	
1240	System Renewal	Pipelines	Bare and Unprotected steel	LOND: Central & Talbot		N	2	-	-	83,232	-	-	
1241	System Renewal	Pipelines	Bare and Unprotected steel	LOND: St Clair & Michigan		N	2	-	-	5,202	-	-	
1242	System Renewal	Pipelines	Bare and Unprotected steel	WIND-Erie Shore & Bisnett Replacement - Harwich		N	2	-	-	40,784	-	-	
1243	System Renewal	Pipelines	Bare and Unprotected steel	WIND-County Rd 27 (south of County Rd 42) Replacement		N	2	-	-	1,794,690	-	-	
1244	System Renewal	Pipelines	Bare and Unprotected steel	LOND: Kent & Talbot		N	2	-	-	130,050	-	-	
1245	System Renewal	Pipelines	Bare and Unprotected steel	LOND: Grosvenor & Gammage		N	2	-	-	43,697	-	-	
1246	System Renewal	Pipelines	Bare and Unprotected steel	LOND: Dalmage & Forward		N	2	-	-	59,303	-	-	

Project Listing for UGL (2019-2023)

Unique Identifier	Investment Category	Asset/Growth Category	Portfolio	Description	ICM - Eligible	Mandatory	Priority	2019 ($)	2020 ($)	2021 ($)	2022 ($)	2023 ($)	Potential for LTC
1247	System Renewal	Pipelines	Bare and Unprotected steel	LOND: Eastman & Highbury		N	2	-	-	348,534	-	-	
1248	System Renewal	Pipelines	Bare and Unprotected steel	LOND:Wavell & Saskatoon		N	2	-	-	41,616	-	-	
1249	System Renewal	Pipelines	Bare and Unprotected steel	LOND:Brydges & Fellner		N	2	-	-	312,120	-	-	
1250	System Renewal	Pipelines	Bare and Unprotected steel	LOND:Cathcart Blvd		N	2	-	-	846,886	-	-	
1251	System Renewal	Pipelines	Bare and Unprotected steel	LOND: Pantry School Road		N	2	-	-	52,020	-	-	
1252	System Renewal	Pipelines	Bare and Unprotected steel	LOND: Michigan & St Clair		N	2	-	-	124,848	-	-	
1253	System Renewal	Pipelines	Bare and Unprotected steel	LOND:Arthur & Victoria		N	2	-	-	99,878	-	-	
1254	System Renewal	Pipelines	Bare and Unprotected steel	LOND:Ernest & Alfred		N	2	-	-	31,212	-	-	
1255	System Renewal	Pipelines	Bare and Unprotected steel	LOND: Church & Water-Beachville		N	2	-	-	104,040	-	-	
1256	System Renewal	Pipelines	Bare and Unprotected steel	LOND: Bee, Burth & Main St - Woodstock		N	2	-	-	197,676	-	-	
1257	System Renewal	Pipelines	Bare and Unprotected steel	LOND: Delatre & Dundas-Woodstock		N	2	-	-	243,454	-	-	
1258	System Renewal	Pipelines	Bare and Unprotected steel	LOND:John & Kains 2		N	2	-	-	62,424	-	-	
1259	System Renewal	Pipelines	Bare and Unprotected steel	LOND:John & Kains 1		N	2	-	-	62,424	-	-	
1260	System Renewal	Pipelines	Bare and Unprotected steel	LOND: Horton & Kains		N	2	-	-	62,424	-	-	
1261	System Renewal	Pipelines	Bare and Unprotected steel	LOND:Princess & Center		N	2	-	-	31,212	-	-	
1262	System Renewal	Pipelines	Bare and Unprotected steel	LOND: St Anne's Place		N	2	-	-	41,616	-	-	
1263	System Renewal	Pipelines	Bare and Unprotected steel	LOND: St George St.-Yarmouth		N	2	-	-	41,616	-	-	
1264	System Renewal	Pipelines	Bare and Unprotected steel	HAMI-Sydenham-Flambourough		N	2	-	162,302	-	-	-	
1265	System Renewal	Pipelines	Bare and Unprotected steel	WAT-Forest - Cambridge		N	2	-	-	166,077	-	-	
1266	System Renewal	Pipelines	Bare and Unprotected steel	WAT- Aberdeen- Cambridge		N	2	-	-	143,774	-	-	
1267	System Renewal	Pipelines	Bare and Unprotected steel	WAT- Churchill - Cambridge		N	2	-	-	43,809	-	-	
1268	System Renewal	Pipelines	Bare and Unprotected steel	WAT-Millvue- Cambridge		N	2	-	-	164,826	-	-	
1269	System Renewal	Pipelines	Bare and Unprotected steel	WAT- Centre - Norwich		N	2	-	-	196,966	-	-	
1270	System Renewal	Pipelines	Bare and Unprotected steel	WAT-Seventh Road - Norwich Twp.		N	2	-	-	31,212	-	-	
1271	System Renewal	Pipelines	Bare and Unprotected steel	WAT- St Patrick - Port Dover		N	2	-	-	20,808	-	-	
1272	System Renewal	Pipelines	Bare and Unprotected steel	WAT- Ada - Brantford		N	2	-	-	205,062	-	-	
1273	System Renewal	Pipelines	Bare and Unprotected steel	LOND- Whetter & Wellington		N	2	-	-	93,636	-	-	
1274	System Renewal	Pipelines	Bare and Unprotected steel	LOND- Belgrave @ Chester		N	2	-	-	72,828	-	-	
1275	System Renewal	Pipelines	Bare and Unprotected steel	LOND-Sycamore & Hume		N	2	-	-	124,848	-	-	
1276	System Renewal	Pipelines	Bare and Unprotected steel	LOND-Wood & Forward		N	2	-	-	83,232	-	-	
1277	System Renewal	Pipelines	Bare and Unprotected steel	LOND-Lecaron Ave & Colborne - Sarnia		N	2	-	-	684,063	-	-	
1278	System Renewal	Pipelines	Bare and Unprotected steel	LOND-Michigan & Arthur		N	2	-	-	18,727	-	-	
1279	System Renewal	Pipelines	Bare and Unprotected steel	HAMI-Inglewood - Burlington		N	2	-	-	338,130	-	-	
1281	System Renewal	Pipelines	Bare and Unprotected steel	WAT- Concession Rd. 12 - Townsend Twp.		N	2	-	-	196,126	-	-	
1282	System Renewal	Pipelines	Bare and Unprotected steel	WAT- Concession Rd. 6 - Townsend Twp.		N	2	-	-	519,339	-	-	
1283	System Renewal	Pipelines	Bare and Unprotected steel	WAT-Woolley - Woodhouse Twp.		N	2	-	-	100,364	-	-	

Project Listing for UGL (2019-2023)

Unique Identifier	Investment Category	Asset/Growth Category	Portfolio	Description	ICM - Eligible	Mandatory	Priority	2019 ($)	2020 ($)	2021 ($)	2022 ($)	2023 ($)	Potential for LTC
1284	System Renewal	Pipelines	Bare and Unprotected steel	WAT- Huron - Brantford		N	2	-	-	54,563	-	-	
1285	System Renewal	Pipelines	Bare and Unprotected steel	WAT- Ryerse Blvd - Port Ryerse		N	2	-	-	162,660	-	-	
1286	System Renewal	Pipelines	Bare and Unprotected steel	HAMI- Napier - Hamilton		N	2	-	-	101,439	-	-	
1287	System Renewal	Pipelines	Bare and Unprotected steel	HAMI-HWY 6 Argyle - Caledonia		N	2	-	-	297,554	-	-	
1288	System Renewal	Pipelines	Bare and Unprotected steel	WAT- Salisbury Avenue - Cambridge		N	2	-	-	139,060	-	-	
1289	System Renewal	Pipelines	Bare and Unprotected steel	WAT - Crescent - Cambridge		N	2	-	-	42,296	-	-	
1290	System Renewal	Pipelines	Bare and Unprotected steel	WAT- Beverly - Cambridge		N	2	-	-	31,212	-	-	
1291	System Renewal	Pipelines	Bare and Unprotected steel	WAT-Rooshill - Cambridge		N	2	-	-	136,446	-	-	
1292	System Renewal	Pipelines	Bare and Unprotected steel	WAT- King St South - Port Ryerse		N	2	-	-	108,010	-	-	
1293	System Renewal	Pipelines	Bare and Unprotected steel	WAT-Creekside Ln - Port Ryerse		N	2	-	-	70,175	-	-	
1294	System Renewal	Pipelines	Bare and Unprotected steel	SARN: Errol East		N	2	-	-	-	1,083,056	-	
1295	System Renewal	Pipelines	Bare and Unprotected steel	WAT- Otterville road 1		N	2	-	-	-	1,560,600	-	
1296	System Renewal	Pipelines	Bare and Unprotected steel	WAT- Otterville road 2		N	2	-	-	-	468,180	-	
1297	System Renewal	Pipelines	Bare and Unprotected steel	WAT- Otterville road 3		N	2	-	-	-	728,280	-	
1298	System Renewal	Pipelines	Bare and Unprotected steel	WAT- Norfolk		N	2	-	-	-	65,751	-	
1299	System Renewal	Pipelines	Bare and Unprotected steel	WIND- County road 31 & Essex County road 2 Replacement		N	2	-	-	-	1,136,637	-	
1300	System Renewal	Pipelines	Bare and Unprotected steel	LOND: St Neots & Ridout		N	2	-	-	-	83,232	-	
1301	System Renewal	Pipelines	Bare and Unprotected steel	LOND: Curry & Piccadilly		N	2	-	-	-	83,232	-	
1302	System Renewal	Pipelines	Bare and Unprotected steel	LOND: Josephine & Maud		N	2	-	-	-	83,232	-	
1303	System Renewal	Pipelines	Bare and Unprotected steel	LOND: Stevenson & Brydges 1		N	2	-	-	-	1,300,500	-	
1304	System Renewal	Pipelines	Bare and Unprotected steel	LOND: Stevenson & Brydges 2		N	2	-	-	-	780,300	-	
1305	System Renewal	Pipelines	Bare and Unprotected steel	LOND: Newell & Michigan - Sarnia		N	2	-	-	-	355,817	-	
1306	System Renewal	Pipelines	Bare and Unprotected steel	LOND: Highbury Pk & Christina		N	2	-	-	-	62,424	-	
1307	System Renewal	Pipelines	Bare and Unprotected steel	LOND: Young St - Woodstock		N	2	-	-	-	124,848	-	
1308	System Renewal	Pipelines	Bare and Unprotected steel	LOND: Cathcart & Alma - Ingersoll		N	2	-	-	-	72,828	-	
1309	System Renewal	Pipelines	Bare and Unprotected steel	WIND-Renaud & Demarse Replacement-Tecumseh		N	2	-	-	-	47,858	-	
1310	System Renewal	Pipelines	Bare and Unprotected steel	HAMI-Brookfield-Dunnville		N	2	-	-	-	297,554	-	
1311	System Renewal	Pipelines	Bare and Unprotected steel	WAT- Wellington East - Otterville		N	2	-	-	-	23,132	-	
1312	System Renewal	Pipelines	Bare and Unprotected steel	CHAT: Thomas & Van Allen MUB Replacement		N	2	-	-	-	23,929	-	
1313	System Renewal	Pipelines	Bare and Unprotected steel	WIND-Canal & Riverside Replacement		N	2	-	-	-	155,540	-	
1314	System Renewal	Pipelines	Bare and Unprotected steel	HAMI-Glassco Avenue - Hamilton		N	2	-	-	162,302	-	-	
1315	System Renewal	Pipelines	Bare and Unprotected steel	HAMI-Brant Street-Dunnville		N	2	-	-	108,202	-	-	
1316	System Renewal	Pipelines	Bare and Unprotected steel	HAMI-Holmesdale Ave -Hamilton		N	2	-	-	135,252	-	-	
1317	System Renewal	Pipelines	Bare and Unprotected steel	HAMI-David Street-Dundas		N	2	-	-	121,727	-	-	
1318	System Renewal	Pipelines	Bare and Unprotected steel	HAMI-Sutor - Rainham		N	2	-	-	405,756	-	-	
1319	System Renewal	Pipelines	Bare and Unprotected steel	SARN: Errol & Christina		N	2	-	-	-	-	716,836	

Project Listing for UGL (2019-2023)

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1320	System Renewal	Pipelines	Bare and Unprotected steel	WAT-Albert St - Langton		N	2	-	-	-	1,077,650	-	
1321	System Renewal	Pipelines	Bare and Unprotected steel	LOND: Seeley Street		N	2	-	-	-	-	62,424	
1322	System Renewal	Pipelines	Bare and Unprotected steel	LOND: Elworthy & Edward		N	2	-	-	-	-	104,040	
1323	System Renewal	Pipelines	Bare and Unprotected steel	LOND: Malcolm Street		N	2	-	-	-	-	62,424	
1324	System Renewal	Pipelines	Bare and Unprotected steel	LOND: Summit & Oxford		N	2	-	-	-	-	62,424	
1325	System Renewal	Pipelines	Bare and Unprotected steel	LOND: Pall Mall & William		N	2	-	-	-	-	62,424	
1326	System Renewal	Pipelines	Bare and Unprotected steel	LOND: Grand & Wellington		N	2	-	-	-	-	83,232	
1327	System Renewal	Pipelines	Bare and Unprotected steel	LOND: Elmwood Place		N	2	-	-	-	-	83,232	
1328	System Renewal	Pipelines	Bare and Unprotected steel	LOND: King & Adelaide		N	2	-	-	-	-	20,808	
1329	System Renewal	Pipelines	Bare and Unprotected steel	LOND: Riverside dr. & Wharncliffe rd.		N	2	-	-	-	-	72,828	
1330	System Renewal	Pipelines	Bare and Unprotected steel	LOND: Tweedsmuir - London		N	2	-	-	-	-	52,020	
1331	System Renewal	Pipelines	Bare and Unprotected steel	LOND: Easy street & Creston		N	2	-	-	-	-	41,616	
1332	System Renewal	Pipelines	Bare and Unprotected steel	LOND: Spruce & Haig		N	2	-	-	-	-	156,060	
1333	System Renewal	Pipelines	Bare and Unprotected steel	LOND: Spruce & Scott		N	2	-	-	-	-	156,060	
1334	System Renewal	Pipelines	Bare and Unprotected steel	LOND:Haig & Spruce		N	2	-	-	-	-	89,474	
1335	System Renewal	Pipelines	Bare and Unprotected steel	LOND Scott & Spruce		N	2	-	-	-	-	104,040	
1336	System Renewal	Pipelines	Bare and Unprotected steel	LOND: Parkway & Huron		N	2	-	-	-	-	124,848	
1337	System Renewal	Pipelines	Bare and Unprotected steel	LOND: Parkway & Sunset		N	2	-	-	-	-	20,808	
1338	System Renewal	Pipelines	Bare and Unprotected steel	LOND: Cheapside & Linwood		N	2	-	-	-	-	12,485	
1339	System Renewal	Pipelines	Bare and Unprotected steel	LOND: Fellner & Langmuir		N	2	-	-	-	-	624,240	
1340	System Renewal	Pipelines	Bare and Unprotected steel	LOND: Wilton & Fellner		N	2	-	-	-	-	305,878	
1341	System Renewal	Pipelines	Bare and Unprotected steel	LOND: Langmuir & Oakland		N	2	-	-	-	-	312,120	
1342	System Renewal	Pipelines	Bare and Unprotected steel	LOND:Copeland & Oxford		N	2	-	-	-	-	405,756	
1343	System Renewal	Pipelines	Bare and Unprotected steel	LOND: Eastlawn & Vroom		N	2	-	-	-	-	349,574	
1344	System Renewal	Pipelines	Bare and Unprotected steel	WAT-Concession road 12 - (Albert St)		N	2	-	-	-	60,800	-	
1345	System Renewal	Pipelines	Bare and Unprotected steel	WAT- George Street 1		N	2	-	-	-	99,830	-	
1346	System Renewal	Pipelines	Bare and Unprotected steel	WAT- Grey Street - Langton		N	2	-	-	-	84,696	-	
1347	System Renewal	Pipelines	Bare and Unprotected steel	WAT- George Street 2		N	2	-	-	-	139,393	-	
1348	System Renewal	Pipelines	Bare and Unprotected steel	WAT-James street		N	2	-	-	-	64,201	-	
1349	System Renewal	Pipelines	Bare and Unprotected steel	WAT-Queen St - langton		N	2	-	-	-	166,555	-	
1350	System Renewal	Pipelines	Bare and Unprotected steel	WAT- Buck's Park		N	2	-	-	-	74,556	-	
1351	System Renewal	Pipelines	Bare and Unprotected steel	WAT- Head N - Simcoe		N	2	-	-	-	110,638	-	
1352	System Renewal	Pipelines	Bare and Unprotected steel	WAT-Windham - Simcoe		N	2	-	-	-	47,952	-	
1353	System Renewal	Pipelines	Bare and Unprotected steel	WAT-King Lane - Simcoe		N	2	-	-	-	71,768	-	
1354	System Renewal	Pipelines	Bare and Unprotected steel	WAT-Tyrell - Simcoe		N	2	-	-	-	189,718	-	
1355	System Renewal	Pipelines	Bare and Unprotected steel	HAMI- Central - dunnville		N	2	-	-	-	446,332	-	

Project Listing for UGL (2019-2023)

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1356	System Renewal	Pipelines	Bare and Unprotected steel	HAMI- South Cayuga - Dunnville		N	2	-	-	-	405,756	-	
1357	System Renewal	Pipelines	Bare and Unprotected steel	HAMI- Haddon - Hamilton		N	2	-	-	-	67,626	-	
1358	System Renewal	Pipelines	Bare and Unprotected steel	HAMI-South Coast - Walpole		N	2	-	-	-	67,626	-	
1359	System Renewal	Pipelines	Bare and Unprotected steel	HAMI - Dunkirk - Hamilton		N	2	-	-	-	74,389	-	
1360	System Renewal	Pipelines	Bare and Unprotected steel	HAMI - HWY 6 - Walpole		N	2	-	-	-	236,691	-	
1375	System Renewal	Pipelines	Bare and Unprotected steel	WAT- Schafer 1 - Middleton		N	2	-	-	-	-	25,928	
1376	System Renewal	Pipelines	Bare and Unprotected steel	WAT- Schafer 2 - Middleton		N	2	-	-	-	-	1,320,421	
1377	System Renewal	Pipelines	Bare and Unprotected steel	WAT- Lawrence Road - Charlotteville twp		N	2	-	-	-	-	74,317	
1378	System Renewal	Pipelines	Bare and Unprotected steel	HAMI- Locke - Dunnville		N	2	-	-	-	838,562	-	
1379	System Renewal	Pipelines	Bare and Unprotected steel	WAT- Murray - Vittoria		N	2	-	-	-	-	224,821	
1380	System Renewal	Pipelines	Bare and Unprotected steel	WAT- New - Vittoria		N	2	-	-	-	-	37,358	
1381	System Renewal	Pipelines	Bare and Unprotected steel	WAT- Water - Vittoria		N	2	-	-	-	-	132,623	
1382	System Renewal	Pipelines	Bare and Unprotected steel	WAT- Rebecca - Vittoria		N	2	-	-	-	-	76,547	
1383	System Renewal	Pipelines	Bare and Unprotected steel	WAT- Colborne - Brantford		N	2	-	-	-	-	38,411	
1384	System Renewal	Pipelines	Bare and Unprotected steel	WAT- Hamilton - Cambridge		N	2	-	-	-	-	476,166	
1385	System Renewal	Pipelines	Bare and Unprotected steel	WAT-Glen Morris		N	2	-	-	-	-	156,060	
1386	System Renewal	Pipelines	Bare and Unprotected steel	HAMI- King William - Caledonia		N	2	-	-	-	74,389	-	
1387	System Renewal	Pipelines	Bare and Unprotected steel	HAMI - Haldimand road 12 - Rainham		N	2	-	-	-	-	74,389	
1388	System Renewal	Pipelines	Bare and Unprotected steel	HAMI- Taylor - Dunnville		N	2	-	-	-	-	74,389	
1389	System Renewal	Pipelines	Bare and Unprotected steel	HAMI- Albion - York		N	2	-	-	-	-	74,389	
1390	System Renewal	Pipelines	Bare and Unprotected steel	HAMI- Port Maitland - Dunn		N	2	-	-	-	-	148,777	
1401	System Renewal	Pipelines	Bare and Unprotected steel	HAMI- Upper Wellington - Hamilton		N	2	-	-	-	-	29,755	
1402	System Renewal	Pipelines	Bare and Unprotected steel	HAMI- Rainham Road - Walpole		N	2	-	-	-	-	845,325	
1418	System Renewal	Pipelines	Bare and Unprotected steel	HAMI - Reg road 8 - Rainham		N	2	-	-	-	-	101,439	
1419	System Renewal	Pipelines	Bare and Unprotected steel	HAMI - Concession 10 - Walpole		N	2	-	-	-	-	74,389	
1420	System Renewal	Pipelines	Bare and Unprotected steel	HAMI - Third Street - Walpole		N	2	-	-	-	-	74,389	
1421	System Renewal	Pipelines	Bare and Unprotected steel	HAMI - King Street - Hagersville		N	2	-	-	-	-	94,676	
1422	System Renewal	Pipelines	Bare and Unprotected steel	SARN: Sarnia Various		N	2	-	-	-	-	312,120	
1423	System Renewal	Pipelines	Bare and Unprotected steel	SARN: Moore Twp Various		N	2	-	-	-	-	416,160	
1424	System Renewal	Pipelines	Bare and Unprotected steel	SARN: Sombra Various		N	2	-	-	-	-	156,060	
1476	System Renewal	Pipelines	Bare and Unprotected steel	WIND_Huron Church Repl_Windsor		N	2	114,403	-	-	-	-	
1477	System Renewal	Pipelines	Bare and Unprotected steel	BRAN-Otterville Rd Leak Repl BU -Norfolk		N	2	404,539	-	-	-	-	
1478	System Renewal	Pipelines	Other	SSM Wallace Terrace Bridge Crossing		N	3	-	34,169	-	-	-	
1484	System Renewal	Pipelines	Bare and Unprotected steel	WIND-Laird from Hanlan to Day Replacement		N	2	-	208,080	-	-	-	
1522	System Renewal	Pipelines	Other	Atikokan Landfill Crossing NPS 10 Repl		Y	1	571,194	-	-	-	-	
1523	System Renewal	Pipelines	Other	WIND_Somme Valve Repl_Windsor		N	3	-	68,543	-	-	-	

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1524	System Renewal	Pipelines	Other	WIND_Red Zoo Valve Repl_Kingsville		N	3	-	219,657	-	-	-	
1525	System Renewal	Pipelines	Other	WIND_Mersea Rd 6 Aerial Repl_Leamington		N	3	-	40,770	-	-	-	
1526	System Renewal	Pipelines	Bridge Crossings	WIND_River Canard Bridge Repl_Lasalle		N	3	-	-	547,085	-	-	
1534	System Renewal	Pipelines	Other	HAMI-MohawkandUpperParadiseRepl-Hamilton		N	3	-	251,956	-	-	-	
1536	System Renewal	Pipelines	Other	NE - Old Hwy 69 PLPRs		N	3	-	235,699	-	-	-	
1568	System Renewal	Pipelines	Cathodic Protection Advancements	WIND_Devonshire Rectifier Bed_Windsor		Y	1	24,480	-	-	-	-	
1569	System Renewal	Pipelines	Cathodic Protection Advancements	WAT-Cambridge Sectionalization		Y	1	100,000	-	-	-	-	
1570	System Renewal	Pipelines	Cathodic Protection Advancements	WAT-Owen Sound Sectionalization		Y	1	187,172	-	-	-	-	
1572	System Renewal	Pipelines	Leakage - Discreet	HAMI-BartonStLeakage-Hamilton		N	2	1,296,483	-	-	-	-	
1573	System Renewal	Pipelines	Bare and Unprotected steel	HAMI-JohnStRepl-Dunnville		N	2	994,392	-	-	-	-	
2031	System Renewal	Pipelines	Bare and Unprotected steel	HAMI-FennellAveELeakage-Hamilton		N	2	727,496	-	-	-	-	
2032	System Renewal	Pipelines	Bridge Crossings	HALT-BronteCreekBridge-Oakville		N	3	-	-	744,190	-	-	
2033	System Renewal	Pipelines	Bare and Unprotected steel	WAT- Bay 2 - Port Rowan		N	2	-	20,471	-	-	-	
2034	System Renewal	Pipelines	Leakage - Discreet	HAMI-BartonStLeakage Phase 2-Hamilton		N	3	-	2,000,000	2,000,000	2,000,000	2,000,000	
2035	System Renewal	Pipelines	Cathodic Protection Advancements	HAMI - 20" Shorted Casing on Hwy 5 -Phase 1		N	3	-	-	3,000,000	-	-	
2036	System Renewal	Pipelines	Cathodic Protection Advancements	HAMI - 20" Shorted Casing on Hwy 5 - Phase 2		N	3	-	-	-	3,000,000	-	
2037	System Renewal	Pipelines	Cathodic Protection Advancements	HAMI - 8" Dunnville Shorted Casing		N	3	-	150,000	-	-	-	
2081	System Renewal	Pipelines	Other	Couchiching, Fort Frances		Y	1	-	-	-	-	1,000,000	
2083	System Renewal	Pipelines	Bridge Crossings	Kapuskasing Bridge		N	3	-	250,000	-	-	-	
2084	System Renewal	Pipelines	Bridge Crossings	Hwy 130 Bridge over Kam River 4" relocation		Y	1	-	600,000	-	-	-	
2086	System Service	Pipelines	Depth of Cover <30% SMYS	Atikokan Lateral - TP8 - Depth of Cover		Y	1	-	-	-	300,000	-	
2087	System Service	Pipelines	Depth of Cover <30% SMYS	Atikokan Lateral - TP14 - Exposed Pipe		Y	1	-	60,000	-	-	-	
2090	System Renewal	Pipelines	Bridge Crossings	WATE - Concession St Bridge Crossing Cambridge		N	3	-	-	-	-	500,000	
2092	System Renewal	Pipelines	Bridge Crossings	WATE - Shade St. Bridge Crossing New Hamburg		N	3	-	-	-	500,000	-	
2093	System Renewal	Pipelines	Bridge Crossings	WATE - 378 Wellington Rd 18 Water Crossing Nichol Twp		N	3	-	100,000	-	-	-	
2210	System Renewal	Pipelines	Other	101 Main St E North Bay		N	3	-	30,000	-	-	-	
2211	System Renewal	Pipelines	Other	133 Main St E North Bay		N	3	-	-	32,000	-	-	
2212	System Renewal	Pipelines	Other	361 Main St E North Bay		N	3	-	-	-	33,000	-	
2213	System Renewal	Pipelines	Other	128 McIntyre St W North Bay		N	3	-	-	-	-	34,000	
2226	System Renewal	Pipelines	Other	Mckeown Ave Repair North Bay		N	3	-	-	-	-	150,000	
2228	System Renewal	Pipelines	Other	Garson Mine Service Replacement Garson		N	3	-	-	-	200,000	-	
2229	System Renewal	Pipelines	Other	Great Northern Rd - Roof Top Meters SSM		N	3	-	-	85,000	-	-	
2230	System Renewal	Pipelines	Other	205 Main St E, North Bay		N	3	-	-	-	-	35,000	
2231	System Renewal	Pipelines	Other	XBOR Lasalle Blvd, Sudbury		N	3	-	-	-	110,000	-	
2241	System Renewal	Pipelines	Other	65 Larch St Valve Cut out (Leak), Sudbury		N	3	-	-	30,000	-	-	
2242	System Renewal	Pipelines	Other	Kingsway Valve repair, Sudbury		N	3	-	-	30,000	-	-	

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2245	System Service	Pipelines	Depth of Cover <30% SMYS	119 Whittaker St Lowering, North Bay		N	3	-	-	-	45,000	-	
2246	System Renewal	Pipelines	Bridge Crossings	Mattawa Bridge		N	3	-	-	-	-	65,000	
2254	System Renewal	Pipelines	Other	Flour Mill Easement, Sudbury		N	3	-	15,000	-	-	-	
2255	System Renewal	Pipelines	Other	inside service on Elgin St., Sudbury		N	3	-	-	10,000	-	-	
2256	System Renewal	Pipelines	Other	unused PLPRs Hamner, Sudbury		N	3	-	20,000	-	-	-	
2258	System Service	Pipelines	Depth of Cover <30% SMYS	Shallow main, Sudbury		N	3	-	-	-	40,000	-	
2259	System Renewal	Pipelines	Other	Crossings through concrete drainage structures, Sudbury		N	3	-	-	25,000	-	-	
2260	System Service	Pipelines	Depth of Cover <30% SMYS	863 Attlee St shallow main, Sudbury		N	3	-	-	-	80,000	-	
2261	System Renewal	Pipelines	Bridge Crossings	Bridge in levack, Sudbury		N	3	-	-	-	-	20,000	
2262	System Renewal	Pipelines	Other	Ironbridge @ Right of Way, SSM		N	3	-	25,000	-	-	-	
2263	System Renewal	Pipelines	Bridge Crossings	Old Garden River Road Bridge Crossing, SSM		N	3	-	-	125,000	-	-	
2265	System Renewal	Pipelines	Other	Day's Inn Bay street, SSM		N	3	-	10,000	-	-	-	
2266	System Renewal	Pipelines	Other	123 March Street, SSM		N	3	-	-	40,000	-	-	
2267	System Renewal	Pipelines	Other	Kingsmount bannister tees, SSM		N	3	-	-	-	20,000	-	
2273	System Renewal	Pipelines	Other	Grasshopper to old levack mine, Sudbury		N	3	-	-	35,000	-	-	
2311	System Renewal	Pipelines	Other	Roseland Phase 1 & 2		N	3	-	-	687,500	-	-	
2313	System Renewal	Pipelines	Bare and Unprotected steel	St Anne from Arbour to County Rd 22 Replacement		N	2	-	-	360,300	-	-	
2315	System Service	Pipelines	Depth of Cover <30% SMYS	5585 Eighth Line Replacement		N	3	-	-	100,000	-	-	
2319	System Renewal	Pipelines	Leakage - Discreet	Chatham Head Office Valve Replacement		N	3	-	115,000	-	-	-	
2326	System Renewal	Pipelines	Other	Erie St N Aerial Crossing		N	3	-	-	-	75,000	-	
2330	System Renewal	Pipelines	Bare and Unprotected steel	Gordon & Elm Replacement		N	2	51,412	-	-	-	-	
2334	System Renewal	Pipelines	Bare and Unprotected steel	Major & East Puce Replacement		N	2	170,000	-	-	-	-	
2337	System Renewal	Pipelines	Leakage - Discreet	Prince Albert and McNaughton Replacement		N	3	-	-	901,117	-	-	
2338	System Renewal	Pipelines	Bare and Unprotected steel	Regent St Replacement		N	2	-	-	150,000	-	-	
2341	System Renewal	Pipelines	Other	Sarnia Line Aerial Crossings		N	3	-	300,000	-	-	-	
2343	System Renewal	Pipelines	Bare and Unprotected steel	Stowe St & Victoria St		N	2	-	140,000	-	-	-	
2349	System Renewal	Pipelines	Leakage - Discreet	Tecumseh Rd E Replacement Phases 3-7		N	3	-	-	-	-	1,701,497	
2350	System Renewal	Pipelines	Other	King- Casing Upgrade District various -		Y	1	-	124,955	124,955	124,955	124,955	
2351	System Service	Pipelines	Other	King- Isolation Valves - District - Inst		Y	1	-	100,643	100,643	100,643	100,643	
2352	System Renewal	Pipelines	Cathodic Protection Advancements	King- Sectionalization Various -District		Y	1	-	163,127	163,127	163,127	163,127	
2413	System Renewal	Pipelines	Bare and Unprotected steel	WAT - Temperance - Waterford		N	2	600,000	-	-	-	-	
2414	System Renewal	Pipelines	Bare and Unprotected steel	HAMI - Thorpe-Dundas		N	2	380,000	-	-	-	-	
2415	System Renewal	Pipelines	Bare and Unprotected steel	WIND - County Rd 22 (from Beechwood to Maplewood) Replacement		N	2	650,000	-	-	-	-	
3	System Renewal	Stations	Replacement of Vaulted Stations	HAMI-KingStETRStn16X-106R-Dundas		N	3	-	-	-	-	500,000	
13	System Renewal	Stations	Stations Capital Maintenance	Plan(T)-Dist-Stn Measuring/Corrosion Stn		N	3	141,337	-	-	-	-	
16	System Renewal	Stations	Stations Capital Maintenance	Plan(T)-Dist-Stn Measuring/Corrosion Stn		N	3	141,337	-	-	-	-	

Project Listing for UGL (2019-2023)

Unique Identifier	Investment Category	Asset/Growth Category	Portfolio	Description	ICM - Eligible	Mandatory	Priority	2019 ($)	2020 ($)	2021 ($)	2022 ($)	2023 ($)	Potential for LTC
206	System Renewal	Stations	Station Painting	Station Painting		Y	1	1,500,000	-	-	-	-	
253	System Renewal	Stations	Stations Capital Maintenance	Plan(T)-Dist-Stn Measuring/Corrosion Stn		N	3	286,091	-	-	-	-	
279	System Renewal	Stations	Stations Capital Maintenance	Plan(T)-Dist-Stn Measuring/Corrosion Stn		N	3	70,475	-	-	-	-	
296	System Renewal	Stations	Stations Capital Maintenance	Plan(T)-Dist-Stn Measuring/Corrosion Stn		N	3	29,385	-	-	-	-	
309	System Renewal	Stations	Stations Capital Maintenance	Plan(T)-Dist-Stn Measuring/Corrosion Stn		N	3	127,321	-	-	-	-	
321	System Renewal	Stations	Stations Capital Maintenance	Plan(T)-Dist-Stn Measuring/Corrosion Stn		N	3	53,051	-	-	-	-	
328	System Renewal	Stations	Stations Capital Maintenance	Plan(T)-Dist-Stn Measuring/Corrosion Stn		N	3	208,645	-	-	-	-	
345	System Renewal	Stations	Stations Capital Maintenance	Plan(T)-Dist-Stn Mea./Cor		N	3	81,423	-	-	-	-	
359	System Renewal	Stations	Stations Capital Maintenance	Plan(T)-Dist-Stn Mea./Cor		N	3	81,423	-	-	-	-	
409	System Renewal	Stations	Obsolete Heating Equipment	WIND_03D-306R Mersea-Gosfield Stn_Leam		N	3	-	-	1,051,696	-	-	
416	System Renewal	Stations	Obsolete Heating Equipment	WIND_03D-301 Leamington North Gate_Leam		N	3	-	220,183	-	-	-	
417	System Renewal	Stations	Obsolete Heating Equipment	WIND_05C-501 Essex Trans Boiler_Essex		N	3	-	246,913	-	-	-	
419	System Renewal	Stations	Obsolete Heating Equipment	CHAT_08F-601 Dover Centre Station_Dove		N	3	-	867,727	-	-	-	
423	System Renewal	Stations	Stations Capital Maintenance	SARN: Suncor Hydrogen Filter Replacement		N	3	-	192,050	-	-	-	
424	System Renewal	Stations	Stations Capital Maintenance	SARN: Oakdale Header Regulator Replacmnt		N	3	-	136,954	-	-	-	
429	System Renewal	Stations	Frost Heave	LOND: Lambeth Leakage - London		N	3	-	683,400	-	-	-	
433	System Renewal	Stations	Stations Capital Maintenance	LOND: Hensall Gate Station Rebuild		N	3	-	685,470	-	-	-	
435	System Renewal	Stations	Obsolete Heating Equipment	LOND: Melrose Gate Boiler Replacement		N	3	-	147,327	-	-	-	
443	System Renewal	Stations	Stations Capital Maintenance	WAT-St Jacobs Trans Stn 20S-602		N	3	-	-	378,630	-	-	
444	System Renewal	Stations	Obsolete Heating Equipment	WAT-Wloo Erbville Gate Stn 19S-602		N	3	-	253,891	-	-	-	
452	System Renewal	Stations	Replacement of Vaulted Stations	HAMI-Hwy5&BrockRdStn17W-605R-Dundas		N	3	-	-	-	594,134	-	
453	System Renewal	Stations	Obsolete Heating Equipment	HAMI-HamiltonGate3Stn16X-601-Hamilton		N	3	-	1,122,297	-	-	-	
455	System Renewal	Stations	Replacement of Vaulted Stations	HALT-CampbellvilleStn19W-601R-Milton		N	3	-	-	500,000	-	-	
460	System Renewal	Stations	Obsolete Heating Equipment	STN Trenton TBS Line Heater		N	3	-	118,739	-	-	-	
461	System Renewal	Stations	Obsolete Heating Equipment	STN Cardinal TBS Lineheater		N	3	-	171,562	-	-	-	
470	System Renewal	Stations	Stations Capital Maintenance	Coniston- Primary Control Valve Repl		N	3	-	265,282	-	-	-	
471	System Renewal	Stations	Stations Capital Maintenance	Espanola DRS		N	3	-	127,748	-	-	-	
508	System Renewal	Stations	Stations Capital Maintenance	WIND_06C-102R Tecumseh&Arlington_Tecumse		N	3	-	52,351	-	-	-	
520	System Renewal	Stations	Stations Capital Maintenance	Dawn Concession 8 Station Repairs		N	3	-	55,197	-	-	-	
526	System Renewal	Stations	Obsolete Heating Equipment	BRAN-Hawtrey Trans Stn 13T-402 Norwich S		N	3	-	112,490	-	-	-	
532	System Renewal	Stations	Frost Heave	WAT-Guelph Hwy 24 19U-601 - Guelph		N	3	-	-	112,490	-	-	
534	System Renewal	Stations	Obsolete Heating Equipment	WAT-Strausburg Trans Stn 18T-501, Wloo		N	3	-	-	905,986	-	-	
535	System Renewal	Stations	Obsolete Heating Equipment	HAMI-LyndenGateStn16V-604-Lynden		N	3	-	185,610	-	-	-	
536	System Renewal	Stations	Replacement of Vaulted Stations	HAMI-SouthBend&UpperJamesStn16X-225R-Ham		N	3	-	-	-	-	500,000	
537	System Renewal	Stations	Replacement of Vaulted Stations	HAMI-TireRd&BurlingtonStStn16Y-110R-Hami		N	3	-	-	500,000	-	-	
538	System Renewal	Stations	Obsolete Heating Equipment	HAMI-SummitTransStn16W-203-Dunnville		N	3	-	-	150,000	-	-	
540	System Renewal	Stations	Replacement of Vaulted Stations	HALT-CorporateDr&ApplebyLnStn18Y-425R-Bu		N	3	-	448,097	-	-	-	

Project Listing for UGL (2019-2023)

Unique Identifier	Investment Category	Asset/Growth Category	Portfolio	Description	ICM - Eligible	Mandatory	Priority	2019 ($)	2020 ($)	2021 ($)	2022 ($)	2023 ($)	Potential for LTC
612	System Renewal	Stations	Stations Capital Maintenance	LOND- Confined Space Removal-Woodstock		N	3	-	398,800	-	-	-	
615	System Renewal	Stations	Obsolete Heating Equipment	King- Cobourg E TBS - Cobourg - Lineheat		N	3	-	-	118,739	-	-	
1174	System Renewal	Stations	Stations Capital Maintenance	Distribution Operations Station Maintenance Blankets		N	2	-	2,012,907	2,012,907	2,012,907	2,012,907	
1175	System Renewal	Stations	Station Painting	Distribution Operations Station Painting		Y	1	-	2,000,000	2,000,000	2,000,000	2,000,000	
1178	System Renewal	Stations	Regulators/Reliefs	Maintenance - Meter Shop Overhead Costs (Regs)		N	2	-	55,189	55,189	55,189	55,189	
1179	System Renewal	Stations	Regulators/Reliefs	Maintenance - Plant Item Costs (Filters/Strainers)		N	2	-	90,378	90,378	90,378	90,378	
1180	System Renewal	Stations	Regulators/Reliefs	Maintenance - Plant Item Costs (Regs)		N	2	-	7,217,229	7,217,229	7,217,229	7,217,229	
1181	System Renewal	Stations	Regulators/Reliefs	Maintenance - Plant Item Costs (Reliefs)		N	2	-	1,667,766	1,550,452	1,541,944	1,806,750	
1182	System Renewal	Stations	Stations Capital Maintenance	Obsolete equipment		N	3	-	1,000,000	100,000	100,000	100,000	
1186	System Renewal	Stations	Stations Capital Maintenance	Regulator Freeze off		N	3	-	1,000,000	100,000	100,000	100,000	
1442	System Renewal	Stations	Stations Capital Maintenance	Class 7 Cambridge		N	3	-	25,000	-	-	-	
1445	System Renewal	Stations	Stations Capital Maintenance	SSM Second Line E Valve		N	3	-	72,782	-	-	-	
1521	System Service	Stations	Hamilton Gate	HAMI - Hamilton Gate 1 and 2 Rebuild		N	3	1,966,237	-	-	-	-	
1527	System Renewal	Stations	Obsolete Heating Equipment	WIND_06B-401 Grand Marais Station Heater		N	2	-	456,651	-	-	-	
1528	System Renewal	Stations	Obsolete Heating Equipment	WIND_06B-301 Lauzon Rd Station Heater Re		N	2	402,469	-	-	-	-	
1529	System Renewal	Stations	Replacement of Vaulted Stations	WIND_03D-101 Kingsville Gate Valve Repl		N	3	-	126,443	-	-	-	
1531	System Renewal	Stations	Obsolete Heating Equipment	LOND: London North Gate Boiler Replaceme		N	3	1,377,485	-	-	-	-	
2040	System Renewal	Stations	Replacement of Vaulted Stations	HALT-Third Line and QEW Vault Station		N	3	-	-	500,000	-	-	
2041	System Renewal	Stations	Frost Heave	HALT-Milton TBS		N	3	-	100,000	-	-	-	
2044	System Renewal	Stations	Frost Heave	HAMI-Airport Rd Station		N	3	-	-	300,000	-	-	
2046	System Access	Stations	Regulators/Reliefs	HAMI - HSR		N	3	-	30,000	-	-	-	
2048	System Renewal	Stations	Obsolete Heating Equipment	HALT - Parkway Transmission		N	3	-	150,000	-	-	-	
2052	System Renewal	Stations	Replacement of Vaulted Stations	HALT-ApplebyLn and Mainway Vault Station		N	3	-	500,000	-	-	-	
2053	System Renewal	Stations	Replacement of Vaulted Stations	HAMI-Cascade and Lake Vault Station		N	3	-	500,000	-	-	-	
2054	System Renewal	Stations	Replacement of Vaulted Stations	HAMI-Malta and Montrose Vault Station		N	3	-	-	500,000	-	-	
2057	System Renewal	Stations	Stations Capital Maintenance	HALT - Procor Lrd		N	3	-	-	15,000	-	-	
2059	System Renewal	Stations	Stations Capital Maintenance	HAMI - Guelph Line and Mt Nemo Station		N	3	-	-	30,000	-	-	
2063	System Renewal	Stations	Replacement of Vaulted Stations	HAMI-Kenora and Bancroft Vault Station		N	3	-	-	500,000	-	-	
2064	System Renewal	Stations	Replacement of Vaulted Stations	HALT-Centennial and Guelph Line Vault station		N	3	-	-	500,000	-	-	
2065	System Renewal	Stations	Replacement of Vaulted Stations	HAMI-Industrial St Vault Station		N	3	-	-	500,000	-	-	
2067	System Renewal	Stations	Frost Heave	HALT-New Oakville Hospital		N	3	-	-	-	50,000	-	
2068	System Renewal	Stations	Replacement of Vaulted Stations	HALT-Winston Churchill and 10 Side Rd Vault Station		N	3	-	-	-	500,000	-	
2069	System Renewal	Stations	Replacement of Vaulted Stations	HAMI-Binkley Rd Vault Station		N	3	-	-	-	500,000	-	
2072	System Renewal	Stations	Replacement of Vaulted Stations	HALT-Plymouth Dr and Winston Churchill Vault Station		N	3	-	-	-	-	500,000	
2103	System Renewal	Stations	Stations Capital Maintenance	Cornwall East TBS rebuild		N	3	-	-	-	-	200,000	
2105	System Renewal	Stations	Frost Heave	LOND: Huron and Clarke		N	3	-	-	32,000	-	-	

Project Listing for UGL (2019-2023)

Unique Identifier	Investment Category	Asset/Growth Category	Portfolio	Description	ICM - Eligible	Mandatory	Priority	2019 ($)	2020 ($)	2021 ($)	2022 ($)	2023 ($)	Potential for LTC
2106	System Renewal	Stations	Obsolete Heating Equipment	LOND: Kerwood Transmission Station		N	3	-	-	-	175,000	175,000	
2107	System Renewal	Stations	Obsolete Heating Equipment	LOND: Ingersoll Transmission Station		N	3	-	-	498,485	-	-	
2108	System Renewal	Stations	Frost Heave	LOND:Autoneum		N	3	-	-	-	22,000	22,000	
2109	System Renewal	Stations	Frost Heave	LOND: Bryanston Gate		N	3	-	-	-	13,000	13,000	
2110	System Renewal	Stations	Frost Heave	LOND: Belton Gate Station		N	3	-	73,000	-	-	-	
2120	System Renewal	Stations	Obsolete Heating Equipment	SARN: NOVACOR (CORUNNA)		N	3	-	-	500,000	-	-	
2123	System Renewal	Stations	Obsolete Heating Equipment	LOND: WHITE OAKS		N	3	-	-	750,000	-	-	
2128	System Renewal	Stations	Obsolete Heating Equipment	LOND: CANADA CEMENT TRANSMISSION STN		N	3	-	-	600,000	-	-	
2130	System Renewal	Stations	Stations Capital Maintenance	LOND: Bonduelle 1st Stage		N	3	-	40,000	-	-	-	
2137	System Renewal	Stations	Station Painting	LOND: Medway Creek Station		Y	1	-	10,000	-	-	-	
2142	System Renewal	Stations	Stations Capital Maintenance	Clarke St. DRS Rebuild		N	3	-	250,000	-	-	-	
2161	System Renewal	Stations	Stations Capital Maintenance	WAT-Waterloo Gate Station 19S-601		N	2	-	90,000	-	-	-	
2162	System Renewal	Stations	Stations Capital Maintenance	WAT-Waterloo Gate Station 19S-601		N	2	-	-	65,000	-	-	
2163	System Renewal	Stations	Frost Heave	WAT-Floradale Gate Station 21S-602		N	3	-	-	112,490	-	-	
2167	System Renewal	Stations	Obsolete Heating Equipment	WAT-Fergus First Stage 21S-601		N	3	-	-	-	-	175,000	
2168	System Renewal	Stations	Obsolete Heating Equipment	WAT-Fergus Second Stage 21U-101		N	3	-	-	-	175,000	-	
2173	System Renewal	Stations	Obsolete Heating Equipment	WAT-Salem Gate Stn 21T-301		N	3	-	-	-	-	175,000	
2174	System Renewal	Stations	Obsolete Heating Equipment	BRAN-Frnlea Farm Trans Stn 12S-202		N	3	-	-	-	112,490	-	
2181	System Renewal	Stations	Obsolete Heating Equipment	WAT-Southampton Trans Stn 30N-501		N	3	-	-	-	200,000	-	
2182	System Renewal	Stations	Obsolete Heating Equipment	WAT-Port Elgin Stn 29N-101		N	3	-	-	-	-	200,000	
2183	System Renewal	Stations	Stations Capital Maintenance	Electrical & Control Integrity Mitigation		N	2	-	100,000	100,000	100,000	100,000	
2186	System Renewal	Stations	Stations Capital Maintenance	AC Mitigation		N	2	-	200,000	200,000	200,000	200,000	
2196	System Renewal	Stations	Stations Capital Maintenance	Espanola DRS		N	3	-	-	-	375,000	-	
2199	System Renewal	Stations	Frost Heave	Rutherglen TBS		N	3	-	-	-	-	500,000	
2201	System Renewal	Stations	Frost Heave	Powassan PRS Rebuild		N	3	-	-	85,000	-	-	
2205	System Renewal	Stations	Stations Capital Maintenance	Sunset PRS Rebuild		N	3	-	-	-	65,000	-	
853	System Service	System Growth	Panhandle	Panhandle Reinforcement		Y	1	500,000	-	-	-	-	
857	System Service	System Growth	Kingsville Transmission Reinf Project	Kingsville Transmission Reinf P*C/O 2018	Y	Y	1	92,471,290	-	-	-	-	Y
1199	System Service	System Growth	Sarnia Industrial System	Sarnia Industrial System	Y	Y	1	3,008,957	60,416,597	1,324,444	-	-	Y
1438	System Service	System Growth	Kingsville Transmission Reinf Project	Kingsville Transmission Reinf Project	Y	Y	1	-	2,757,452	-	-	-	Y
2411	System Service	System Growth	Dawn Parkway System	2015 Dawn to Parkway		Y	1	1,504,000	-	-	-	-	
2412	System Service	System Growth	Dawn Parkway System	2017 Dawn to Parkway		Y	1	6,960,399	-	-	-	-	
204	System Service	Underground Storage	Storage Integrity	STO STORAGE WELL UPGRADES		Y	1	250,000	-	-	-	-	
383	System Service	Underground Storage	Storage Improvements	Well Optimization Program		N	2	372,814	-	-	-	-	
403	System Service	Underground Storage	Storage Improvements	Wellhead Upgrade Project		N	3	-	568,857	-	-	-	
1155	System Service	Underground Storage	Storage Improvements	Emergency Shutdown Valve Installation		N	3	-	950,000	800,000	800,000	900,000	

Project Listing for UGL (2019-2023)

Unique Identifier	Investment Category	Asset/Growth Category	Portfolio	Description	ICM - Eligible	Mandatory	Priority	2019 ($)	2020 ($)	2021 ($)	2022 ($)	2023 ($)	Potential for LTC
1156	System Service	Underground Storage	Storage Integrity	Well Integrity - Maintenance Capital upgrades (STO - STORAGE WELL UPGRADES)		Y	1	-	250,000	250,000	250,000	250,000	
1158	System Service	Underground Storage	Storage Improvements	Well Optimization program		N	2	-	372,814	372,814	372,814	372,814	

ENBRIDGE GAS INC.
Answer to Interrogatory from
Building Owners and Managers Association of Greater Toronto (BOMA)

Reference: Exhibit C1, Tab 1, Schedule 1; Utility System Plan/EGD, p27

Question:

For each of Union and EGD, what are the percentage capitalized overheads added to the consolidated capital budget? Please itemize the parts of overhead and explain the company's capitalization policies and relevant accounting policy for each part.

Response

The percentage of capitalized overheads added to the EGD budget is 28.5%.

The percentage of capitalized overheads added to the UG budget is 15.5%.

Please refer to Exhibit I.STAFF.32 for an explanation of the components of overhead.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Building Owners and Managers Association of Greater Toronto (BOMA)

Reference: Exhibit C1, Tab 1, Schedule 1; Utility System Plan/EGD, p28

Question:

Please compare EGD's Lifetime Risk Return on Investment approach and Union's prioritization and risk ranking methodology used to develop their respective capital plans. Please provide a document that illustrates the use of each of these methods in arriving at EGD's and Union's capital plans, including the prioritization of the constituent capital projects.

Response

Please see Exhibit I.VECC.12.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Building Owners and Managers Association of Greater Toronto (BOMA)

Reference: Exhibit C1, Tab 1, Schedule 1; Utility System Plan/EGD, p29

Question:

a) Please itemize and describe how "opportunities outside of core business activities that have different funding … mechanisms and supported through public and governmental policies/regulations" are dealt with in the prioritization process. Do they rank ahead of all of the core business opportunities, behind all core business activities, or otherwise. Please explain.

b) As among price, safety, and reliability, which do customers of each rate zone rank first, second, and third priority?

Response

a) Non-core business activities are not considered in the prioritization process of core capital and follow a separate approval process. As indicated on page 29 in the Company's USP, filed at Exhibit C1, Tab 1, Schedule 1, opportunities outside of core business activities that have different funding mechanisms and are driven and supported through public and governmental policies/regulations, (such as Community Expansion, renewable natural gas, etc.), do not flow through the prioritization process.

b) The Customer Engagement survey in the EGD rate zone did not ask customers to prioritize between price, safety, or reliability.

In the Union rate zones, as indicated on page 10 in the Customer Engagement survey filed at Exhibit D1, Tab 2, Schedule 1, customers generally rate price as the top priority followed by safety and reliability. Some business customers prioritize reliability over safety.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Building Owners and Managers Association of Greater Toronto (BOMA)

Reference: Exhibit C1, Tab 1, Schedule 1; Utility System Plan/EGD, pp30-31

Question:

Please provide the extent to which current EGD and Union programs are able to "meter measure" the results of their CDM programs.

Response

Both of Enbridge Gas's Run it Right and Run Smart program offerings estimate cumulative cubic metres ("CCM") of natural gas savings by leveraging the metered gas consumption from each participating facility.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Building Owners and Managers Association of Greater Toronto (BOMA)

Reference: Exhibit C1, Tab 1, Schedule 1; Utility System Plan/EGD, pp31-32

Question:

Please describe the in-field studies on CDM impacts on infrastructure demand currently underway, and state when they will be available.

Response

The two in-field case studies that are currently underway are at various states of implementation / completion. Information from the case study underway in Ingelside Ontario will be available late 2019 or early 2020 and information from the case study in Deep River ON is anticipated to be available later in 2020.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Building Owners and Managers Association of Greater Toronto (BOMA)

Reference: Exhibit C1, Tab 1, Schedule 1; Utility System Plan/EGD, p33

Question:

Please confirm that the utilities' integrity capital management programs are part of annual OM&A and/or budgets. Please provide details of each utility's integrity capital management program for 2019.

Response

Confirmed.

The EGD rate zone's integrity capital management program for 2019 can be found at Exhibit C1, Tab 2, Schedule 1, section 5.2.4, page 113.

The Union rate zones' integrity capital management program for 2019 can be found at Exhibit C1 Tab 3 Schedule 1, page 84.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Building Owners and Managers Association of Greater Toronto (BOMA)

Reference: Exhibit C1, Tab 1, Schedule 1; Utility System Plan/EGD, p34

Question:

Please explain why the capital expenditure plans are made for a ten year period. Please provide details. Has the ten year forecast always been used by each utility? How does the five year EGD and Union utility system plan and, eventually, the single Enbridge Gas system plan, get distilled from the ten year plans? Please provide prioritized lists of projects to be initiated in each of the five years of each utility system plan.

Response

Capital expenditure plans are made over a 10 year horizon to identify future needs for asset investments and make proactive decisions whenever possible. It supports the organizations in its ability to plan, resource and execute the work and consider proactive life cycle management decisions and rate impacts over a longer term. The EGD rate zone has completed a 10 year asset plan since 2013, and the Union rate zone has completed a 10 year asset plan since 2016.

Enbridge Gas's utility system plan is the first five years of the EGD and Union rate zones' 10-year Asset Management Plans for regulated capital.

Please see Exhibit I.BOMA.22 for a listing of all projects for both the EGD and Union rate zones.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Building Owners and Managers Association of Greater Toronto (BOMA)

Reference: Exhibit C1, Tab 1, Schedule 1; Utility System Plan/EGD, p35

Question:

Please explain what EGD meant by "tacit knowledge". Your evidence suggests that EGD and Union currently use two different risk assessment approaches in their capital planning. What are the relative strengths and weaknesses of each approach? How do you propose to reconcile those two approaches to achieve the best possible approach for the new combined utility?

Response

The EGD rate zone uses the term tacit knowledge to distinguish information that comes from people, and information that comes from databases and other structured sources. In the context of risk assessment, it is often necessary to rely on tacit knowledge to identify hazards, and to establish their likelihood and potential consequence.

Both the EGD and Union rate zones use tacit knowledge extensively in risk assessments. Union has used a 5 x 5 matrix to define the severity of the risk whereas EGD has developed more quantitative risk assessments.

Risk assessment methods can range from qualitative through semi-quantitative and quantitative. The strength of a more qualitative approach is that it can be done relatively quickly if the risk is clearly low (requiring no further action) or clearly high (requiring mitigation). A qualitative assessment is not as useful if there are a number of potential hazards that may interact and lead to consequences that are magnified by the interaction of the potential hazards. Conversely, a quantitative risk assessment can account for increased complexity with many contributing and escalating factors and layers of protection. The weakness of the quantitative risk assessment is that it requires a lot of data and a lot of time from risk specialists and those that are knowledgeable about the process that is under examination. These methods are all widely used and are appropriate based on the purpose of the risk assessment.

As per the response at STAFF.34, Enbridge Gas is still assessing its future asset management processes.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Building Owners and Managers Association of Greater Toronto (BOMA)

Reference: Exhibit C1, Tab 1, Schedule 1; Utility System Plan/EGD, p37

Question:

(a) In Tables 6, 7, 8, 9, 10, and 11, what is meant by the phrase "direct capital" along the vertical access? For each of EGD and Union, what other capital, in addition to direct capital, is forecast to be spent over the ten year planning period by each? How much in 2019? Please discuss in detail.

(b) Will the projects "under development", currently not included in EGD's and Union's forecast ten year spending, be added to that spend? In approximately which year, and in what amounts? Please provide ranges if exact amounts not available. Will these projects, if they receive the authority to proceed, displace existing projects in the current five and ten year project lists, or will they require additional capital, to be financed by ICM funding, or otherwise?

Response

a) Figures 6, 7, 8, 9, 10, and 11 are incorrectly labelled and should read ‘net capital’ along the vertical axis as they include both direct and indirect capital.

b) Projects “under development” will be included in Enbridge Gas’s spend when their scope, timing, and cost are more developed.

Please refer to section 6.3, page 391, in EGD rate zone’s AMP filed at Exhibit C1, Tab 2, Schedule 1 for the approximate year and amounts of these projects for EGD. In Union rate zone, the only project that has been identified as under development in the Union rate zone for which capital expenditures are not yet estimated is for the Dawn to Parkway System expansion Exhibit C1, Tab 3, Schedule 3 page 75. Cost estimates are currently under development. The known details of this project are outlined in Exhibit I.FRPO.25.

If these projects receive authority to proceed, the capital requirements will be considered along with all other capital requirements over the 10 year horizon.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Building Owners and Managers Association of Greater Toronto (BOMA)

Reference: Exhibit C1, Tab 1, Schedule 1; Utility System Plan/EGD, p36; Table 2

Question:

For each of EGD and Union, how much of system access (in millions of dollars) is accounted for by mandatory projects in each year? BOMA defines mandatory projects to be projects required by law, for example, replacements due to road widening, other municipal infrastructure, or other projects requiring compliance. What do EGD and Union include in the category of compliance projects or mandatory projects over and above the projects EGD and Union are legally required to do, as described in this question? Please describe for each of EGD and Union, the capital projects in their respective prioritized list of projects are ones required to mitigate what they describe as an intolerable risk. Please define what they consider to be an intolerable risk, and provide examples.

Response

"System access investments are additions and modifications (including asset relocation) to a distributor's system that a distributor is obligated to perform in order to provide a customer or group of customers with access to natural gas services via the distribution system."[1]

In the EGD rate zone, 96% of the System Access capital requirements are classified mandatory. In the Union rate zones 100% of the System Access capital requirements are classified mandatory. The EGD and Union rate zones' capital expenditure for the 10 year planning period for all categories are provided in the USP.[2]

Mandatory and compliance projects are defined in the EGD rate zone's AMP at Exhibit C1, Tab 2, Schedule 1, Table 4.1-4, page 74. Excerpts are provided below.

> A risk that must be addressed within its required time window. Mandatory risks can be the result of:

[1] Exhibit C1, Tab 1, Schedule 1, page 35.
[2] Ibid., page 40 – 41.

- Compliance requirements
- Exceeding a risk limit where the risk is assessed within EGD's intolerable risk region
- Third-party relocation driven
- Program work with sufficient history and risk to warrant continuation[3]

Compliance is defined as:

"Required adherence with applicable laws and regulations, industry codes, standards, and internal policies."[4]

The Union rate zones define mandatory projects at Exhibit C1, Tab 3, Schedule 1, page 57. Mandatory projects are considered Priority 1 and are related to:

- Compliance-related items
- Growth
- Contractual Obligations
- Risk Rank 1 Items

Where, "Risk Rank 1 projects are considered a significant risk that is intolerable and requires notification to the president within 48 hours of discovery. Short-term mitigation plans must be put in place in less than four weeks and the target to implement long-term mitigations is less than six months. In cases where this is not possible, specific approvals must be attained."[5]

The system access category does not contain any projects with an intolerable risk classification.

Please see Exhibit I.BOMA.22 for a complete listing of projects in the Enbridge Gas asset plans.

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[3] Exhibit C1, Tab 2, Schedule 1, Table 4.1-4, page 74.
[4] Ibid.
[5] Exhibit C1, Tab 3, Schedule 1, page 57.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Building Owners and Managers Association of Greater Toronto (BOMA)

Reference: Exhibit C1, Tab 1, Schedule 1; Utility System Plan/EGD, p43

Question:

Please explain what Table 3 is intended to show.

Response

Please see Exhibit I.STAFF.39.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Building Owners and Managers Association of Greater Toronto (BOMA)

Reference: Exhibit C1, Tab 1, Schedule 1; Utility System Plan/EGD, p45

Question:

For 2019, for each of EGD and Union rate zones, please prioritize all capital projects within each category of the capital budget, eg. system access, system renewal, etc.

Response

Please see Exhibit I.BOMA.22 for a complete summary of all projects in the Enbridge Gas asset plans.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Building Owners and Managers Association of Greater Toronto (BOMA)

Reference: Exhibit C1, Tab 1, Schedule 1; Utility System Plan/EGD, p47

Question:

Please provide the lifecycle calculations and 5x5 matrix underlying EGD's and Union's respective risk assessment methodologies.

Response

The EGD rate zone quantifies its risk and uses the risk matrix as a tool to present risks and opportunities for informational purposes. The EGD rate zone's risk methodology and 7x7 matrix can be found in section 4.2.1, filed at Exhibit C1, Tab 2, Schedule 1, page 79.

The EGD rate zone's lifecycle information can be found Exhibit C1, Tab 2, Schedule 1, Section 5, pages 95 to 374.

The Union rate zones' utilizes a 5x5 risk matrix to evaluate risk. Details of the risk management process can be found at Exhibit C1, Tab 3, Schedule 1, pages 51 to 58. The Union rate zones' methodology for determining the overall risk is qualitative and as such does not generally rely on calculation to arrive at the overall risk level.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Building Owners and Managers Association of Greater Toronto (BOMA)

Reference: Exhibit C1, Tab 1, Schedule 1; Utility System Plan/EGD, p48

Question:

Please explain how the examples given for "maintenance projects", Dawn C Plant Replacement, Windsor Line Replacement, and SCOR Meter Area upgrade, are funded. Please provide amounts broken down into capital and OM&A.

Response

Enbridge Gas is not seeking any relief for the projects specified in the question in 2019. Accordingly, Enbridge Gas declines to respond.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Building Owners and Managers Association of Greater Toronto (BOMA)

Reference: Exhibit C1, Tab 1, Schedule 1; Utility System Plan/EGD, p49

Question:

a) Please provide, for each project, for which EGD or Union is seeking ICM treatment in 2019, the amount to be expended in the 2019 capex, the 2019 assets in-service, and the impact on the 2019 revenue requirement, the project capital expenditures, and in-service assets for each year 2020, 2021, 2022, and 2023, and revenue requirement for each of those years.

b) For the Sudbury Lateral Replacement, please provide the year in which it entered service, the capital expenditure for each year from its initiative to its in-service date in 2018.

c) How does the Sudbury project meet ICM criteria?

d) Does EGD intend to ask for ICM treatment for all the projects listed in Table 49 over the term of the five year plan? If not, for which projects?

Response

a) Please see Exhibit B1, Tab 2, Schedule 1, Appendix E, pages 1 to 4 for the detailed revenue requirement calculations for the projects with 2019 assets in-service for each year 2020, 2021, 2022 and 2023. Appendix E, page 3 has been updated and is filed along with the interrogatory response.

b) Please see Exhibit I.EP.16.

c) Please see Exhibit I.STAFF.24 part (a).

d) All of the projects listed in Exhibit C1, Tab 1, Schedule 1, page 49, Table 6 represent potential ICM Projects over the five year plan.

Kingsville Transmission Reinforcement - ICM Project Revenue Requirement

Line No.	Particulars ($000's)	2019 (a)	2020 (b)	2021 (c)	2022 (d)	2023 (e)
	Incremental Rate Base Investment					
1	Capital Expenditures	118,183	3,171	-	-	-
2	Average Rate Base	14,677	118,411	117,650	115,287	112,924
	Incremental Revenue Requirement Calculation:					
	Return on Incremental Rate Base: (1)					
3	Long-term Debt Interest	588	4,740	4,709	4,615	4,520
4	Short-term Debt Interest	(0)	(1)	(1)	(1)	(1)
5	Preference Shares	12	99	98	96	94
6	Equity	472	3,807	3,782	3,706	3,630
7	Total Return on Incremental Rate Base	1,072	8,645	8,589	8,417	8,244
	Incremental Operating Expenses:					
8	Operating and Maintenance Expenses	-	-	-	-	-
9	Depreciation Expense (2)	192	2,331	2,363	2,363	2,363
10	Property Taxes (3)	45	270	274	278	282
11	Total Incremental Operating Expenses	237	2,601	2,637	2,641	2,645
	Incremental Income Taxes:					
12	Return on Equity and Preference Shares (line 5 + line 6)	484	3,906	3,881	3,803	3,725
	Utility Timing Differences					
13	Add: Depreciation Expense (line 9)	192	2,331	2,363	2,363	2,363
14	Less: Current Year Tax Deductions	(13,617)	(8,948)	(7,985)	(7,209)	(6,527)
15	Taxable Income (line 12 + line 13 + line 14)	(12,941)	(2,711)	(1,741)	(1,044)	(439)
16	Income Taxes Before Gross Up (line 15 x 26.5%) (4)	(3,429)	(719)	(461)	(277)	(116)
17	Total Incremental Income Taxes After Gross Up (line 16 / (1-26.5%) (4) (5)	(4,666)	(978)	(628)	(376)	(158)
18	Total Incremental Revenue Requirement (line 7 + line 11 + line 17)	(3,358)	10,269	10,598	10,681	10,731

Notes:

(1) The return on rate base is calculated based on Union's 2013 Board-approved capital structure:

Capital Structure	Component %	Cost Rate	Return Component
Long-term Debt	61.30%	6.53%	4.00%
Short-term Debt	-0.03%	1.31%	0.00%
Preference Shares	2.74%	3.05%	0.08%
Equity	36.00%	8.93%	3.21%
Total	100.00%		7.30%

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

(3) Incremental property tax costs as a result of the project facilities.

(4) Union's current provincial and federal tax rate is equal to 26.5%.

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

ENBRIDGE GAS INC.
Answer to Interrogatory from
Building Owners and Managers Association of Greater Toronto (BOMA)

Reference: Exhibit C1, Tab 1, Schedule 1; Utility System Plan/EGD, pp51-53; Tables 9, 10, and 11

Question:

(a) What is the total amount of projects in-service with proposed ICM financing:

(i) in 2019;

(ii) over the five year period 2019-2023; and

(iii) amounts in 2019 and 2020-2023, including overhead.

(b) What would be the impact on the revenue requirement of implementing the proposed ICM projects in 2019, in each year from 2020 to 2023?

(c) Please provide the actual and normalized ROE compared to allowed ROE for each of EGD and Union, in each of the last five years, 2018, 2017, 2016, 2015, and 2014.

Response

a) i) The total amounts of projects in service with proposed ICM funding can be found at Exhibit B1, Tab 2, Schedule 1, Table 8.

ii-iii) The 2019 ICM projects and potential ICM projects for 2020 – 2023 can be found at Exhibit C1, Tab 1, Schedule 1, Table 6.

b) The revenue requirement of each of the 2019 ICM projects for 2020 to 2023 can be found at Exhibit B1, Tab 2, Schedule 1, Appendix E, pages 1-4. Please refer to Exhibit B1, Tab 2, Schedule 1, page 35 for Enbridge Gas's ICM unit rate proposal for 2019 – 2023.

c) Please see Table 1 below for the EGD and Union rate zones' ROE's for 2013-2018.

Table 1
UNION ROE 2013-2018 (%)

	2013 (1)	2014 (1)	2015 (1)	2016 (1)	2017 (2)	2018 (3)
Actual ROE (4)	10.67	10.69	9.89	9.24	9.16	9.66
Weather Normalized ROE (4)	9.73	9.23	9.46	9.78	9.55	9.36
Board-Approved ROE	8.93	8.93	8.93	8.93	8.93	8.93

EGD ROE 2013-2018 (%)

	2013 (1)	2014 (1)	2015 (1)	2016 (1)	2017 (1)	2018 (3)
Actual ROE (4)	11.13	12.39	10.41	8.76	9.71	11.41
Weather Normalized ROE (4)	10.41	10.46	9.82	9.42	10.27	10.66
Board-Approved ROE	8.93	9.36	9.30	9.19	8.78	9.00

Notes:

(1) EB-2017-0306/0307, Exhibit C.LPMA.18, Pages 2-3.
(2) EB-2018-0105, Exhibit A, Tab 2, Appendix B, Schedule 1/Exhibit A, Tab 5, Page 5.
(3) 2018 Return on equity figures draft. The actual amounts will be filed later this year as part of Enbridge Gas's 2018 Earning Sharing Mechanism and Deferral and Variance Account proceeding.
(4) Actual and weather normalized ROE's do not reflect the impact of earnings sharing amounts where applicable.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Building Owners and Managers Association of Greater Toronto (BOMA)

Reference: Exhibit C1, Tab 2, Schedule 1, p17; EGD Asset Management Plan

Question:

Please provide a copy of ISO 5500X.

Response

ISO 5500X refers to a suite of ISO Asset Management guidelines:

- ISO 55000: *Asset Management – What to do and Why*
- ISO 55001: *Asset Management - Management Systems: Requirements*
- ISO 55002: *Guidelines for the application of ISO 55001*

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ENBRIDGE GAS INC.
Answer to Interrogatory from
Building Owners and Managers Association of Greater Toronto (BOMA)

Reference: Exhibit C1, Tab 2, Schedule 1, p19

Question:

Please provide a copy of the revised Strategic Plan in 2018.

Response

The 2018 Strategic Plan summary referenced in EGD's Asset Management Plan is filed as Attachment 1.

2018 Strategic Plan Summary

ENBRIDGE
Life Takes Energy

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Long-Term Vision

Our vision is to be the leading energy delivery company in North America, and our five strategic intents represent our long-term road map for the future. They guide our decision making at both big-picture strategic and day-to-day tactical levels. They establish our direction to build a sustainable, successful Enbridge for decades to come.

The five strategic intents are:

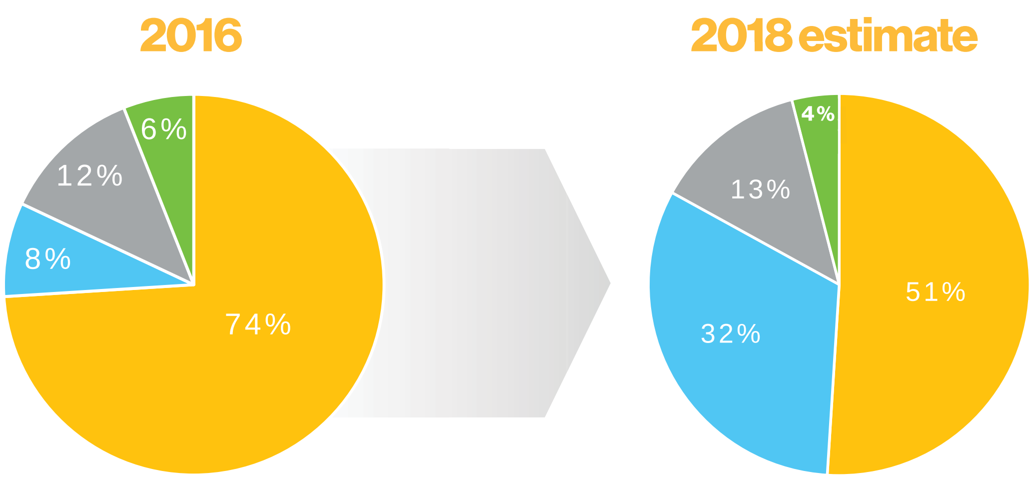
- Be an energized and proud team
- Deliver the energy people need and want
- First choice of our customers
- Trusted by our stakeholders
- A must-own investment

The New Enbridge

At Enbridge, we exist to fuel people's quality of life.

We are North America's premier energy infrastructure company, connecting key supply basins with consuming markets to move a very large slice of North America's oil, natural gas and natural gas liquids, safely and reliably. As a leading, global-scale infrastructure company, we are critical to the North American economy.

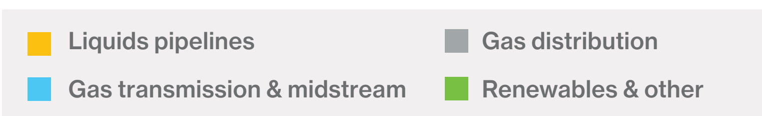
Today, Enbridge is balanced between oil and natural gas, including North America's premium natural gas transmission franchise, our world-class liquids pipeline business and our top-notch gas utility business. This footprint provides us with scale and diversity to compete, to grow and to provide the energy people need and want.



EBITDA* = C$6.9B
Total Assets = C$86B

EBITDA* = ~ C$12.5B
Total Assets = ~ C$171B

* Earnings before interest, taxes, depreciation and amortization



Strategic Plan

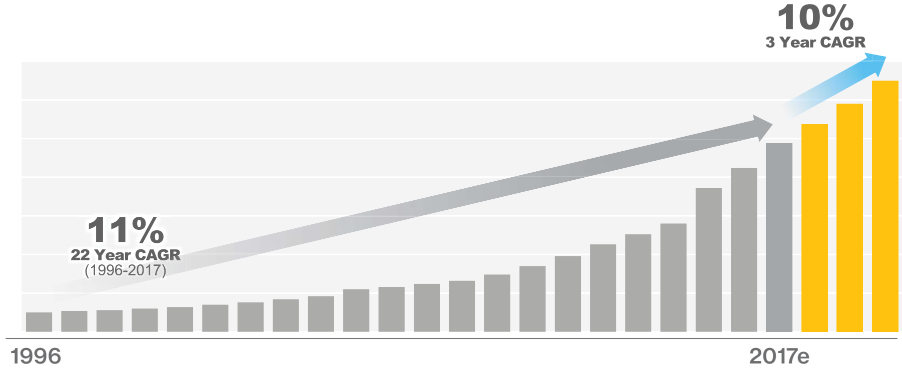
Enbridge's Strategic Plan sets out a course for the company with a forward outlook focused on the next three years. The Plan reflects a critical assessment of our much larger asset base, and it takes into account the current business environment, characterized by lower commodity prices in our near-term planning horizon, intensified competition and ongoing opposition to pipeline development.

Our goal is to not just be the biggest, but the best performing company in our industry.

Our three-year Plan will achieve that by focusing our attention on what we do best—growing our 'crown jewel' pipeline and utility assets, and selling or monetizing assets that do not fit this model. Our core assets have highly predictable cash flows, align with our low risk value proposition and a large set of organic growth opportunities through which to expand and extend our existing assets. While we have strong competitive advantages in each business, we must continuously get better at what we do and lower our cost structure. With a significant amount of growth capital already secured through 2020, project execution, cost management and maintaining our financial strength and flexibility remain critical to our long-term success.

Successful execution of our Strategic Plan will enable us to grow cash flow on average by approximately 10% annually through 2020, which supports our ability to deliver on a commensurate average compound annual growth rate of 10% through 2020.

Dividend Growth Outlook



Our Strategic Priorities

Based on external and internal factors, our strategic plan is focused on the following six strategic priorities:

1. Safety & Operational Reliability

2. Execute Capital Program

3. Maximize Value of Core Business

4. Position for Long-term Growth

5. Strengthen Financial Position

6. Complete Integration & Transformation

Maintain the Foundation

- Uphold Enbridge Values
- Maintain the trust of our stakeholders
- Attract, retain & develop highly capable people

Our Six Strategic Priorities

1. Focus on Safety and Operational Reliability

Above all else, safety and reliability of our operations remains our number one priority. If we fail to meet our safety and operational goals, our business as a whole cannot deliver the outcomes laid out in this strategic plan. We will continue to strive for industry safety and reliability leadership and drive a strong performance-based safety culture.

2. Execute Capital Program

Over the next three years, we plan to spend $22 billion on organic growth opportunities within our core assets. Our secured capital program includes projects such as the Line 3 Replacement, NEXUS, Dawn-Parkway Expansion and the Hohe See Offshore Wind project. Project execution is both integral to our near-term financial performance and balance sheet strength, but also to positioning the business for the long-term. It therefore remains a critical priority for execution teams to manage challenges and engage proactively with regulators and communities.

3. Maximize Value of Core Business

We are re-focusing Enbridge's asset mix to a pure regulated pipeline and utility business model: liquids pipelines and terminals; gas transmission and storage; and natural gas utilities. This will enable us to continue to deliver on our low-risk, reliable value proposition. These core assets have similar characteristics:

- **Strategic asset positioning** – linking key supply basins with large, growing demand markets;
- **Strong commercial underpinnings** – long-term contracts, established customers, strong risk-adjusted returns; and
- **Organic growth opportunities** – the ability to create value by repurposing, reconfiguring and replacing assets already in the ground.

4. Position for Long-Term Growth

A company of our size requires a large opportunity set to sustain growth. We will continue to evaluate new opportunities within our core businesses that fit our value proposition and position Enbridge for the energy mix of the future. As we grow, we are committed to being part of the transition to a lower carbon economy across all our businesses. Natural gas will play an important role and we continue to see significant opportunities in offshore wind.

5. Strengthen Financial Position

To execute on our secured capital program and to position the company for long-term growth, it will be important to further bolster the balance sheet and provide additional funding flexibility. Our funding plan is designed to sustain strong investment-grade credit ratings, which are key to efficiently funding future growth. We have already begun taking actions to ensure we maintain an industry-leading balance sheet.

6. Complete Integration & Transformation

We will remain focused on transforming how we do business by optimizing our systems and processes, and driving cost efficiencies to ensure we remain highly competitive and effective in the future. To maintain a competitive cost structure, we must achieve top quartile cost performance, which will require a renewed focus on how and where we spend our money.

Non-core Businesses

Our non-core assets include certain non-regulated natural gas midstream gathering and processing (G&P) businesses and onshore renewable assets. Our plan is to monetize or sell a portion or all of those businesses over time. These are valuable assets, but they no longer fit the profile of our core businesses and will be more valuable to another player.

This is not an exit from renewables. We may only sell a portion of our onshore business and we will continue to invest in offshore wind. Investing in these projects remains integral to our longer-term positioning of Enbridge's energy infrastructure mix.

Attractive Investor Value Proposition

Our Strategic Plan emphasizes our attractive investor value proposition. We offer investors a unique combination of strong organic growth and a stable, low risk business model that enables premium dividend growth. In the last three years alone we have grown the dividend by 62% and we're confident that our Strategic Plan will continue to deliver superior shareholder value.

Maintain the Foundation

Underpinning the Strategic Plan are the foundational elements of our company: adhering to our values; maintaining trust of our stakeholders; and developing our people.

Uphold Enbridge Values

We adhere to a strong set of core values that govern how we conduct our business and pursue strategic priorities, as articulated in our value statement: “Enbridge employees demonstrate integrity, safety and respect in support of our communities, the environment and each other.” Employees are expected to uphold these values in their interactions with each other, customers, suppliers, landowners, community members and all others with whom we deal, and to ensure our business decisions are consistent with these values.

Maintain the Trust of Our Stakeholders

Earning and maintaining the trust of our stakeholders is critical to our ability to execute on our growth plans. We are increasingly focused on building long-term relationships by understanding, accommodating and resolving public concerns related to our projects and operations. We engage our key stakeholders through collaboration and by demonstrating openness and transparency in our communication. We also publicly advocate company positions on key issues and policies that are critical to our business. Ultimately, we strive to build awareness of the role that energy plays in people’s lives and how the energy our company generates and delivers contributes in a meaningful way to their standard of living, health and prosperity.

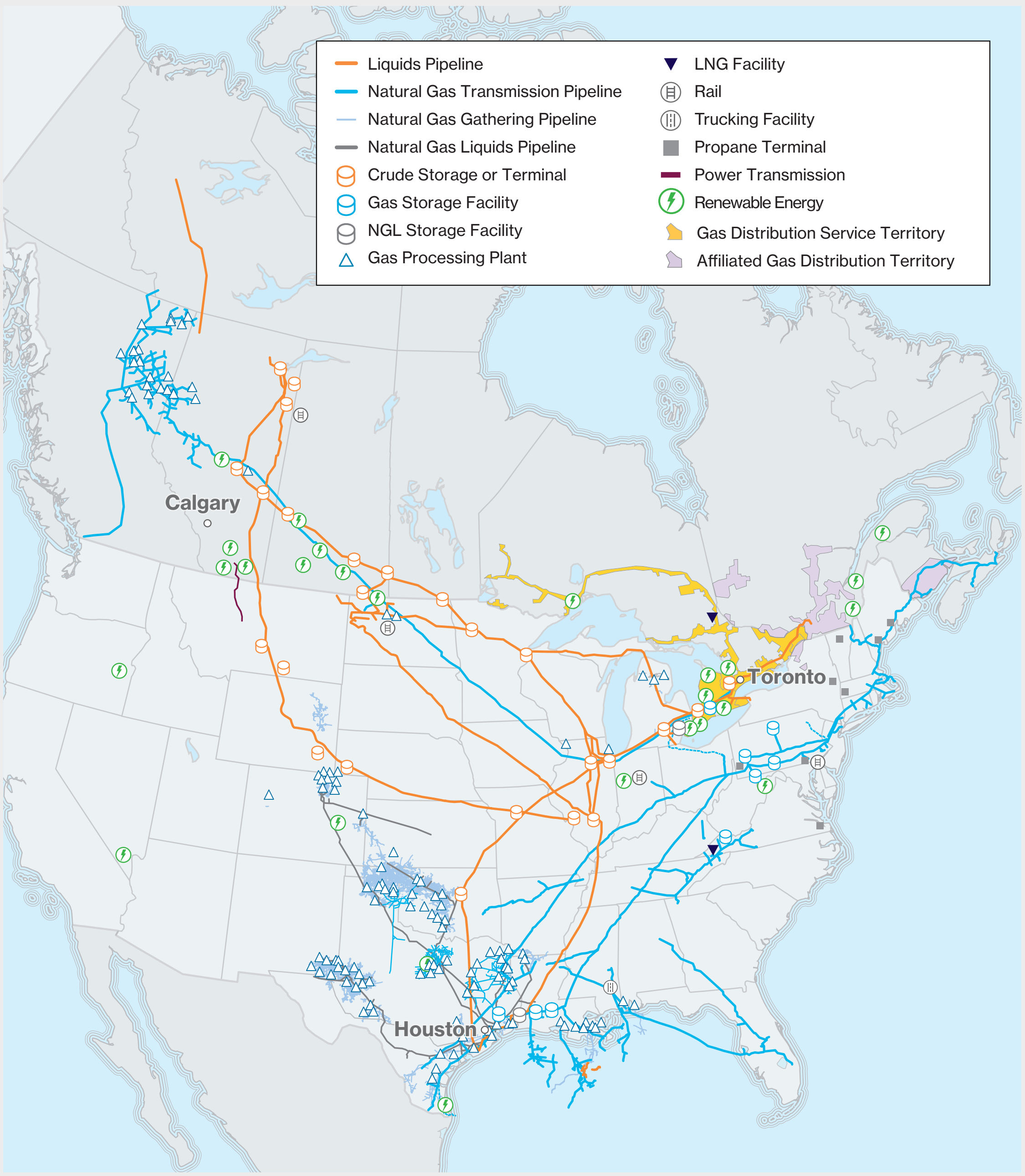
Develop our Highly Capable People

Our employees are fundamental to executing our Strategic Plan, to leading through large-scale change and to delivering on the long-term success of our organization. We all need to think and act like owners of the business—this is our company. Greater ownership and accountability will lead to an energized, engaged and proud team.

Business Units

The overarching strategy for each of our business units is to: maximize the value of our core business, execute on major projects and position the business for growth until 2020 and beyond. The following pages provide an overview of each core business, including our competitive advantage for each area, and how Enbridge will continue to be the first choice for our customers.

Enbridge Operations



Liquids Pipelines

Enbridge's world-class pipeline network is North America's premier crude system. The size and scale, and geographic reach, along with the absolute criticality of our system to producers and refiners, gives our system a strong competitive position.

Over the last few years, Enbridge's crude oil and liquids network has evolved to offer customers unparalleled market access and flexibility. The Mainline System, which moves Western Canadian crude to markets in Eastern Canada and the U.S. Midwest, remains the heart of our portfolio. It ships 2.85 million barrels per day of light and heavy crudes along with natural gas liquids and refined products.

Liquids Pipelines

We operate approximately 30,040 kilometers (18,666 miles) of liquids pipelines—making it the world's longest and most complex crude oil and liquids transportation system.

Execute Capital Program

Our main priority over the next three years is to ensure our Mainline System remains full and to protect our dominant competitive position. We will continue to focus on mainline expansion by increasing capacity and optimizing the system. Execution of the Line 3 Replacement project – expected to be in service in late 2019 – is a critical element of the liquids strategy. We will also increase capacity of our Southern Access Pipeline to move incremental western Canadian barrels.

Post-2019 we see opportunities for staged capacity expansion across our mainline, should either Keystone XL or the Trans Mountain Expansion project not move ahead as scheduled.

Position for Long-term Growth

In addition to the mainline suite of growth projects post-2019, other opportunities for growth through expansion include:

- Expansion capability on Flanagan South/Seaway systems;
- Involvement in the potential Capline reversal, connecting Patoka to the eastern Gulf Coast;
- Expansion potential for the Express/Platte and Dakota Access lines; and
- Opportunity to establish a strategic footprint in the U.S. Gulf Coast terminal and pipeline business.

We also see other development opportunities within key supply basins, including the Oil Sands, North Dakota and the Permian.

Gas Transmission and Midstream (GTM)

Enbridge's gas transmission assets are unrivaled in the industry due to their scale, scope and connectivity. What sets us apart is our first and last mile advantage; we connect North America's most prolific supply areas to the continent's major demand centres.

This competitive advantage has helped drive our base business. Our customer base consists largely of stable and growing gas and electric companies, and when our customers grow, we grow by supporting them.

GTM has solid, low-risk revenues that underpin the business.

Execute Capital Program

In addition to our 'rock solid' base business, we have visible, contractually secured growth for the next three years. Our secured growth program will extend our system and provide geographic diversity.

Position for Long-Term Growth

We believe the next wave of projects will be regional in scope, rather than the massive, multi-state projects we've built in the past. We will participate in future growth by leveraging our significant asset footprint. We see growth opportunities in the following regions:

- Rising demand in the Gulf Coast, the rapidly growing epicenter of America's liquefied natural gas (LNG) and Mexican exports;
- Retiring electricity generation sources, such as coal, being replaced by natural gas in the U.S. Northeast and New England;
- Continued growth in natural gas-fired power generation in the U.S. Southeast; and
- Expansions in Western Canada to support producers looking for egress solutions out of the Montney and Duvernay regions.

Gas Transmission and Midstream

Our gas pipelines cover more than 54,700 kilometers (34,000 miles) in 31 U.S. states, five Canadian provinces and offshore in the U.S. Gulf of Mexico. In the United States, we are no longer a south-to-north pipeline system. Our Texas Eastern system is a fully bi-directional pipeline that delivers gas from the Marcellus and Utica basins to markets in the East, South and Midwest U.S.

We have connections to utilities in Manhattan and Philadelphia; we are the largest supplier to New England, the Southeast and virtually all of Florida; and our transmission network also webs its way throughout the Gulf Coast.

In Western Canada, our pipelines directly link supply areas like the Montney to markets in southern British Columbia, the Pacific Northwest and the U.S. Midwest.

Utilities

Enbridge has the best situated natural gas utility business in Canada. We are located in major growth centres and are connected to diverse gas supplies. Our utilities business is an extremely strong growth platform as we provide gas to heat homes, run businesses and transport goods.

We deliver energy to 3.6 million homes and businesses in Ontario, Quebec, New Brunswick and New York State—a number that is growing.

Our priorities over the next three years are to support customer growth and rate base renewal, including delivering energy to new communities, and expansion of our Dawn Hub.

Execute Capital Program

Customer Growth

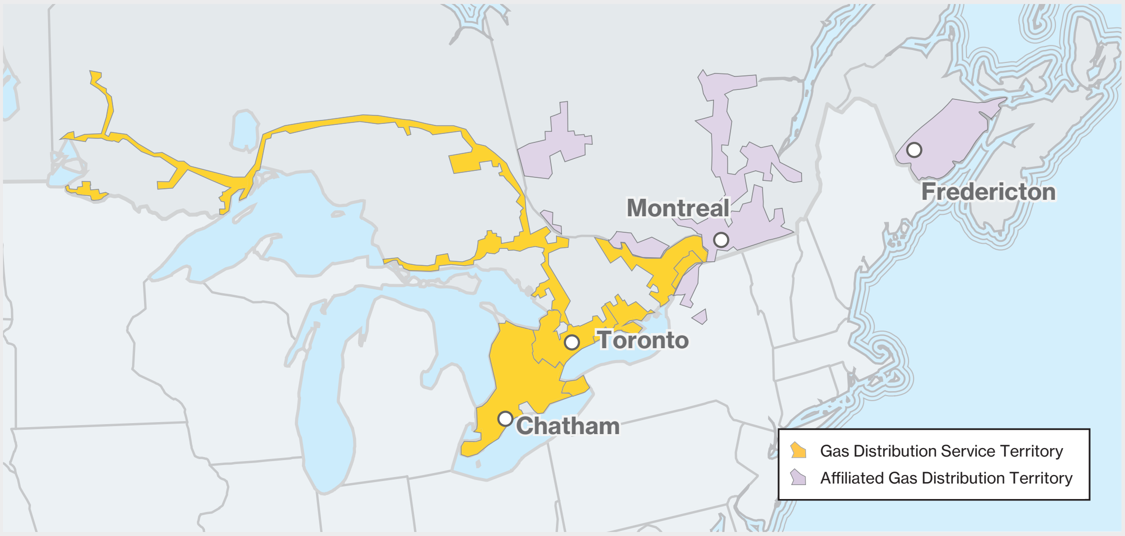
Each year, our utilities add over 50,000 customers and deploy capital in excess of $1 billion to maintain and grow our assets. We expect customer growth to remain strong, driven by Ontario population growth and demand for natural gas as a cost effective source of energy. In Ontario, natural gas can cost as little as one-third of alternatives. We are also expanding into new markets in Ontario, partially supported by a government grant program to help bring natural gas to remote locations, including Indigenous communities.

We will continue to build connecting pipelines and expansions to support commercial growth in southwestern Ontario.

Transportation and Storage

Our storage facilities in Ontario, including Dawn and Tecumseh in the southwestern part of the province, feature a total of 278 billion cubic feet of storage—the energy equivalent of more than 60% of Ontario’s annual electricity consumption. Our storage is connected to supply basins across North America, including the Utica and Marcellus in the U.S. Northeast and the Montney and Duvernay in Western Canada.

Gas Distribution



Utility Amalgamation Plan

We applied to the OEB to amalgamate Enbridge Gas Distribution and Union Gas on January 1, 2019—a development that would create the single largest natural gas utility in North America in terms of send-out volumes, and third largest in terms of customers.

This harmonization would drive efficiencies and synergies, leverage greater supply-chain strength, create new opportunities for growth, and form a stronger platform to deliver strong, predictable returns to shareholders and superior value and service to customers.

Position for Long-Term Growth

We will continue to develop opportunities over the next several years to support a lower carbon future in Ontario, including:

- Expanding generation and capture of Renewable Natural Gas (RNG) from landfill waste;
- Increasing the use of Compressed Natural Gas (CNG) in transportation, particularly in urban transportation systems like buses and garbage trucks as well as heavy-haul transportation; and
- Integration of gas and electric infrastructures using technologies like combined heat and power, geothermal loops and hydrogen storage and blending.

Forward Looking Information

This document includes references to forward-looking information. By its nature this information applies certain assumptions and expectations about future outcomes, so we remind you it is subject to risks and uncertainties that affect every business, including ours. The more significant factors and risks that might affect future outcomes for Enbridge are outlined in "Forward-Looking Information", slide four of the Enbridge Investor Days Opening Remarks slide presentation, available here: **https://www.enbridge.com/~/media/Enb/Documents/Investor%20Relations/2017/2017_ENBDays_OpeningRemarks.pdf**

ENBRIDGE®
Life Takes Energy®

ENBRIDGE GAS INC.
Answer to Interrogatory from
Building Owners and Managers Association of Greater Toronto (BOMA)

Reference: Exhibit C1, Tab 2, Schedule 1, p20

Question:

a) Please provide a copy of Pipeline Integrity Management Program document. Please define what integrity means. How do "integrity mains" differ from distribution steel mains? What are length, diameter, and pressures of integrity mains? Please distinguish vital mains from integrity mains. Please define CSAT Risk.

b) Please discuss the various categories of mains, their risk/opportunities. What are typical end of life ages for those categories of mains?

c) Please describe how "leak projections" are made.

d) Please summarize the leak survey intervals for each category of mains. Are there any exceptions to those time periods?

Response

a) The Pipeline Integrity Management Program is described in further detail in Exhibit C1, Tab 2, Schedule 1, pages 113 to115.

Please define what integrity means.

System Integrity is described in Table 5.2-1 “Maintain the natural gas distribution system to meet or exceed codes, standards, and the requirements of applicable governmental authorities for safety and operational effectiveness.” (Reference: Exhibit C1, Tab 2, Schedule 1, page 106)

How do “integrity mains” differ from distribution steel mains?

Integrity Mains are defined as “Integrity Management Program (IMP) mains are all pipelines operating at stress levels of 30% Specified Minimum Yield Strength (SMYS) and greater, and targeted Vital Mains that operate at stress levels less than 30% SMYS.” (Exhibit C1, Tab 2, Schedule 1, page 113)

Distribution Steel Mains are steel pipelines operating less than 30% SMYS and do not include IMP steel mains.

<u>What are length, diameter, and pressures of integrity mains?</u>

There are 403 km of Integrity Mains as inventoried within Table 5.2-3 (Exhibit C1, Tab 2, Schedule 1, page 109). The diameter and pressures vary but are specified as "all pipelines operating at stress levels of 30% Specified Minimum Yield Strength (SMYS) and greater, and targeted Vital Mains that operate at stress levels less than 30% SMYS." (Exhibit C1, Tab 2, Schedule 1, page 113)

<u>Please distinguish vital mains from integrity mains.</u>

Vital Mains consist of all NEB regulated lines, integrity lines, transmission lines and select distribution lines. Vital mains are critical to the safe and reliable operation of the gas distribution system.

Integrity Mains (as defined above) are a subset of Vital Mains.

<u>Please define CSAT Risk.</u>

Customer Satisfaction Risk (CSAT) is a risk category that is comprised of the following risk dimensions:

i. Emissions (GHG)
ii. Rehabilitation
iii. Operational Reliability
iv. Reputational

(Exhibit C1, Tab 2, Schedule 1, Page 81)

b) Please refer to table 5.2.3. (Exhibit C1, Tab 2, Schedule 1, Pages 110 to 111)

c) As outlined in Exhibit C1, Tab 2, Schedule 1, page 132 – section 5.2.6.1: "…leak projection model created by applying a structured methodology to convert historical failure data into a statistical model that forecasts the probability of failure (PoF). The leak projections are refined with input obtained through direct assessment, internal and external industry studies, and SMA input." ("SMA" is a Subject Matter Advisor)

d) A leak survey is conducted every five years for distribution steel mains and distribution plastic mains as indicated in the "Maintenance Strategy" within table 5.2.3. (Exhibit C1, Tab 2, Schedule 1, Page 110); exceptions are given for vital mains and pipelines identified with extensive hard surface cover, for which they are surveyed annually.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Building Owners and Managers Association of Greater Toronto (BOMA)

Reference: Exhibit C1, Tab 2, Schedule 1, p21

Question:

(a) Please provide a copy of the 1977 – 1985 plastic main integrity assessment.

(b) Do you proactively replace plastic mains on basis of age alone? Please discuss.

(c) Do you conduct condition assessments of all mains assets?

(d) How many copper ICMs services mains in operation? What is the average age? What are plans to replace them?

(e) How do you determine when a valve on a pipe is leaking?

(f) Please distinguish between system reinforcement, asset replacement, and asset removal.

(g) What steps are being taken to address valves in poor condition?

Response

a) The integrity assessment on 1977 to 1985 plastic main is a proposed strategy for that specific asset sub-class. The assessment will be initiated in 2019 and targeted for completion over the next 5 years.

b) No. The current focus of the vintage plastic replacement program is to replace the mains that have shown the effect of rapid degradation due to stress factors such as rock impingement.

c) Not on all mains. Condition of Integrity Mains is assessed through in-line inspection, while direct assessments are performed opportunistically on distribution mains during maintenance activities. The condition information obtained from this direct assessment is used in our predictive analytics to support the development of statistical models to help inform asset health. (Exhibit C1, Tab 2 / Schedule 1, page 113 to 114, section 5.2.4.1)

d) There are no copper mains in the system, only copper services. The average age of the remaining active copper services is approximately 49 years. (Exhibit C1, Tab 2 Schedule 1, page 21, section 1.8.2). There are approximately 5,100 active copper services in operation at the time the Asset Plan was written. The current plan is to replace all copper services with steel or plastic services over the next 10 years. (Exhibit C1, Tab 2, Schedule 1, page 143, figure 5.2 to 41)

e) When a potential leak is detected through the Leak Survey program or when a suspected gas leak is reported by the public to Enbridge Gas, a leak investigation is conducted to confirm if it is a natural gas leak and to determine the gas source. Leaks on valves can also be detected during the valve inspection program.

f) As per Exhibit C1, Tab 2, Schedule 1, page 159, section 5.2.11:

> System Reinforcement projects involve the installation or modification of existing gas distribution assets to maintain minimum required system pressures, maintain distribution capacity, and meet growing natural gas demands. These projects are primarily driven by increased customer demand, customer growth and system reliability considerations.

Asset replacement pertains to the like-for-like replacement of an asset to address condition issues.

Asset removal refers to the removal from service, either physically or more commonly by abandonment in place where the asset is disconnected from the distribution system and replaced by a new asset under asset replacement.

g) When an issue is identified on a valve, it will be assessed by field operations to determine if the issue can be remedied through maintenance work or repair. In the event where the valve is not repairable, it will be replaced.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Building Owners and Managers Association of Greater Toronto (BOMA)

Reference: Exhibit C1, Tab 2, Schedule 1, p31

Question:

(a) Have the April 2018 federal methane reduction regulations come into force? Please provide a copy, or a link to where the regulations can be found. What steps are Union and EGD taking to comply with the regulations?

(b) Please confirm that any revenue from the sale of buildings or facilities in 2019 will accrue to the ratepayers. Does either EGD or Union intend to sell land or facilities in 2019? Which ones?

Response

a) Environment and Climate Change Canada ("ECCC") published the final "Regulations Respecting the Release of Methane and Certain Volatile Organic Compounds (Upstream Oil and Gas Sector)" (the "methane regulation"), to reduce methane emissions from Canada's Oil and Gas Sector in Canada Gazette, Part II, on April 28th, 2018. The methane regulation applies to the upstream oil and gas sector which includes the transmission and storage segment of the natural gas industry, but not the distribution segment. A copy of the regulation can be found at https://laws-lois.justice.gc.ca/eng/gregulations/SOR-2018-66/. Beginning in 2020, the following regulatory requirements will come into force:

- Annual measurement requirements and emission limits for reciprocating compressor unit rod packing and centrifugal compressor unit seals

- Leak Detection and Repair ("LDAR") requirements for natural gas storage and transmission facilities

Enbridge Gas is in the process of developing a plan to ensure compliance with the 2020 regulatory requirements, for legacy Union and legacy EGD facilities. Key steps in the plan include preliminary testing (2018/2019) of rod packing and seal emissions from compressor units in order to identify potential compliance issues and development of a resource plan and schedule to meet the new LDAR requirements for 2020. Future work will include an assessment of high bleed pneumatic devices and other venting sources in order to ensure compliance with additional regulatory requirements coming into force in 2023. Enbridge, in conjunction with the natural gas industry, is also continuing consultation with ECCC, to provide further clarity on the implementation of the regulatory requirements.

Based on testing completed to date, EGD has developed and began implementing plans in order to meet the regulated emission rate for some of its large bore reciprocating compressors.

b) Not confirmed. At present, Enbridge Gas does not have any planned land or facility sales for 2019.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Building Owners and Managers Association of Greater Toronto (BOMA)

Reference: Exhibit C1, Tab 2, Schedule 1, p45

Question:

(a) Please explain what Fig. 1.9-2 is intended to show.

(b) Please confirm that for 2019, $364M represents the base capital.

(c) Please confirm that the only EGD ICM request for 2019 is the NPS Don River Replacement. What is the amount being requested for 2019 in-service capital? In what year did the remainder of the capital for Don River Replacement come into service, and in what amounts? Please provide the business case.

(d) Please provide a priority listing, and a business case, if one is not already in evidence, for each of the other ICM eligible capital projects listed in Fig. 1.9-5.

(e) Please describe the steps EGD takes to establish its proposed 2019 capex. Please show how each step leads to the prioritized project list requested above.

Response

a) Figure 1.9-2 is an illustration from the EGD rate zone's PowerPlan Asset Management Planning ("PP-AMP") levelling tool that shows the profile of capital spend from 2019 to 2028 (excluding total overheads) prior to the annual portfolio optimization process. "*The initial spend profile is the result of the previous optimization and approved portfolio, with the addition of new business cases and updates to existing ones*".[1]

The different colour blocks illustrate the various projects and programs, the hatched area illustrates those that are mandatory and fixed, and the red line from years 2019 to 2023 illustrates the optimization capital as derived from Table 1.9-3.[2]

[1] Exhibit C1, Tab 2, Schedule 1, page 44.
[2] Ibid.

b) $364 million represents the total capital prior to the EGD rate zone's optimization process (excluding overhead) for the year 2019; this includes base capital and ICM-eligible capital.

c) Confirmed, the Don River Replacement project is the only project in the EGD rate zone for which ICM treatment is being requested. The 2019 in-service capital is $34.2 million. The remaining capital comes into service in 2020 and amounts to $1.1 million. Please refer to Table 9 in Exhibit B1, Tab 2, Schedule 1. As shown in Table 8 in Exhibit B1, Tab 2, Schedule 1, the Company is seeking for partial funding for the Don River Replacement project of $13.1 million due to the amount of ICM capital exceeding the maximum eligible incremental capital amount. The business case for this project can be found in Exhibit C1, Tab 2, Schedule 1, page 699.

d) The table below shows the 2019 ICM-eligible project and future potential ICM projects listed in Table 1.9-5 with reference to the respective business cases.

Project Name	**Business Case Reference**
NPS 30 Don River Replacement	Exhibit C1, Tab 2, Schedule 1, page 699
NPS 20 Don River Relocation	Exhibit C1, Tab 2, Schedule 1, page 694
SCOR: Meter Area Upgrade	Exhibit C1, Tab 2, Schedule 1, page 1176
NPS 12 St. Laurent Ottawa North Main Replacement	Exhibit C1, Tab 2, Schedule 1, page 708
Kennedy Road Expansion	Exhibit C1, Tab 2, Schedule 1, page 1292
NPS 12 Martin Grove Road Main Replacement Phase 2	Exhibit C1, Tab 2, Schedule 1, page 703
VPC Core and Shell Obsolescence	Exhibit C1, Tab 2, Schedule 1, page 1332
SMOC/Coventry Consolidated Facility	Exhibit C1, Tab 2, Schedule 1, page 1282

e) The EGD rate zone's Asset Management process of establishing its proposed capital expenditure budget is illustrated at Figure 4.2-1.[3] The relevant steps described for this response include steps 1, 2, 3a, 3b, 6, 7, 8, 9, 10.

<u>Step in EGD's Asset Management Core Process (from Figure 4.2-1):</u>	**<u>Description of how this informs capital budget:</u>**
1. Risk/Opportunity Identification 2. Business Case Initiation 3a. Quantitative Risk Assessment (Ro)	Risks and opportunities are identified by the business and preliminary risk is assessed. A business case is created in PP-AMP. [Refer to Exhibit C1, Tab 2, Schedule 1, Page 79-82 for details.]
3b. Quantitative Risk Assessment (Ro, Rn) 6. Business Case Scope Development & Cost Estimation 7. Asset Manager Review & Approval of Business Case	Solution scope and cost estimation is developed by the business. Risk assessment is advanced with solution planning. Completed risk assessment and solution details are incorporated on the business case in PP-AMP. Asset Class Manager (ACM) reviews and approves the business case for consideration in portfolio optimization. [Refer to Exhibit C1, Tab 2, Schedule 1, Page 83-84 for details.]
8. Portfolio Optimization 9. Review & Approval of Asset Class Optimized Portfolio 10. Approved Portfolio	In the process of portfolio optimization at EGD the "Annual Net Direct Capital is constrained, and the lifetime pre- and post-solution risks determined by QRAs are analyzed to minimize the total risk associated with the portfolio over a specific timeframe" " [Exhibit C1, Tab 2, Schedule 1, Page 84]. All ACM endorsed project and program business cases are considered in portfolio optimization. An overview of the process is described in Exhibit C1, Tab 2, Schedule 1, Page 84-86. *"Running the leveling tool (as outlined in Section 4.2.3) at the defined optimization capital (Table 6.1-1), an optimized solution could not be obtained. This was due to the level of fixed and mandatory projects. To resolve this, business cases that met the incremental capital criteria (Table 6.1-2) were removed from the leveling process and leveling was repeated until an optimized solution was obtained. Since ICM-eligible capital is different in kind from initiatives carried out through base capital, removing these initiatives from levelling provided EGD with the best understanding of an optimized typical base spend profile. ICM eligible business cases (presented in Table 6.1-3) were considered in addition to the optimized result. Where possible, through subsequent reviews of the results, ICM-eligible capital was proposed within the optimization capital and treated as base (Table 6.1-1). The optimized result is illustrated in Figure 6.1-2."* [Exhibit C1, Tab 2, Schedule 1, Page 377].

[3] Exhibit C1, Tab 2, Schedule 1, page 78.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Building Owners and Managers Association of Greater Toronto (BOMA)

Reference: Exhibit C1, Tab 2, Schedule 1, p47

Question:

Please provide the amount of capitalized overhead costs, as defined in Table 1.10-1, that is not included in that number, and the components of capital overhead costs.

Response

The amount of capitalized overhead can be found in table 1.9-3, page 44 in EGD rate zone's AMP filed at Exhibit C1, Tab 2, Schedule 1.

Please see Exhibit I.STAFF.32 part (c) for an explanation of the components of capital overhead costs.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Building Owners and Managers Association of Greater Toronto (BOMA)

Reference: Exhibit C1, Tab 2, Schedule 1, p48

Question:

Please provide copies of any third party Asset Condition/Management studies utilized to determine the proposed capex in 2019 for each of EGD and Union.

Response

EGD and Union use the results of consultant studies, internal and external data, and tacit knowledge to identify risks and opportunities that may require investment. The various solutions that are considered to address the risk or opportunity are developed within EGI. It is these solutions that would be the primary drivers of the capex required to address the risk or opportunity.

At Legacy EGD, the decision to include or exclude an investment from the capex is the result of the asset management process which is depicted in section 4.2, page 77 in EGD rate zone's AMP filed at Exhibit C1, Tab 2, Schedule 1.

At Legacy Union, the decision to include or exclude an investment from the capex is the result of the portfolio prioritization process which is described on page 34 to 65 in Union rate zone's AMP, filed at Exhibit C1, Tab 3, Schedule 1.

As such, there are no consultant studies that determine the proposed capex explicitly.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Building Owners and Managers Association of Greater Toronto (BOMA)

Reference: Exhibit C1, Tab 2, Schedule 1, p49

Question:

Please discuss what is meant by "reliability engineering". How does it work? How is it distinguished from, for example, engineering, civil engineering, mechanical engineering, electrical engineering?

Response

Reliability Engineering focuses on the continued ability of an asset or component to perform its intended function. The key is to understand the function of the component within the system as a whole, and to establish how it might fail (failure modes) and the consequences related to each failure mode.

To establish the reliability of a system as a whole, it is important to understand the failure frequencies and consequences related to each of the system's components. For this reason, Reliability Engineering is often focused on failure and consequence data, as well as predictive analytics.

Reliability Engineers can have a background in any Engineering discipline, including those mentioned above.

As defined on page 47 in EGD rate zone's AMP, filed at Exhibit C1, Tab 2, Schedule 1, reliability engineering describes the role of data and predictive analytics in establishing asset health.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Building Owners and Managers Association of Greater Toronto (BOMA)

Reference: Exhibit D1, Tab 1, p5

Question:

For EGD, have there been any surveys done since August 2017, the delivery date of the Final IPSOS Report? Please describe generically, who are rate 6 customers – typical rate 6 business customers.

Response

Please see Exhibit I.BOMA.8.

As per EGD's Rate Handbook, the applicability of Rate 6: General Service is defined as follows:

"To any applicant needing to use the Company's natural gas distribution network to have transported a supply of natural gas to a single terminal location ("Terminal Location") for non-residential purposes"

Typical customers taking Rate 6 include the following:

Apartment and condominium buildings;
Office buildings;
Schools;
Hospitals and other medical buildings;
Churches;
Hotels and motels;
Shopping malls;
Warehouses;
Various retail buildings and stores;
Restaurants

ENBRIDGE GAS INC.
Answer to Interrogatory from
Building Owners and Managers Association of Greater Toronto (BOMA)

Reference: Exhibit D1, Tab 1, pp5-7

Question:

Please describe the impact of the margin of error for the four cohorts on the usefulness of the survey data.

Response

The margin of error is a statistic expressing the confidence one should have in the sampling error for survey results. The statistic considers the total size of the survey universe and the size of the survey sample. Generally, the larger the sample size the lower the margin of error. Also, the larger the universe generally means that a larger sample size would be more appropriate. For context, an industry standard sample size for the population of Ontario (18+ adults) is n=800 interviews.

As a measure of sampling error the impact of the margin of error means that the results of the Residential customer survey can be considered accurate between plus or minus 3%, the results of the General Service customer survey can be considered accurate between plus or minus 4%, the results of the Rate 6 Business customer survey can be considered accurate between plus or minus 6%, and the Large Volume customer survey can be considered accurate between plus or minus 13%.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Building Owners and Managers Association (BOMA)

Reference: Exhibit D1, Tab 1, p8

Question:

(a) The data for satisfactory customer service, 72% Rate 6, 66% Rate 6, 66%R, GS (65%) seems rather low, with only two-thirds of customers expressing satisfaction.
(b) Given that satisfaction with value for money also were 72% (6), 66%LV, 66%R, 65T GS, what steps is EGD planning to increase these numbers for both customer service and value for money?

Response

Please see Exhibit I.STAFF.77.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Building Owners and Managers Association (BOMA)

Reference: Exhibit D1, Tab 1, pp15-17

Question:

(a) Why have a significantly higher percentage of general service customers experienced outages than the residential rate 6, or large volume customers?
(b) Why have general service and rate 6 customers who experienced one unplanned outage over the last five years, also on average experienced 2.6 outages per year?

Response

a) The research indicates that General Service customers are more likely to experience an unplanned natural gas outage compared to Residential customers (8% vs 5%, respectively). There is no statistically significant difference with self-reported experiences of unplanned natural gas outages between General Service and Rate 6 or Large Volume customers.

Ipsos cannot comment why a higher proportion of General Service customers, compared to Residential customers, have ever experienced an unplanned natural gas outage.

b) To clarify, question 3 (Q4 for LVC customers) asks respondents if they have ever experienced an unplanned natural gas outage. Question 4 (Q5 for LVC customers) asks, among those who indicate that they have ever experienced an unplanned natural gas outage, how many unplanned outages they have experienced in the past 5 years.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Building Owners and Managers Association (BOMA)

Reference: Exhibit D1, Tab 1, p19

Question:

A large minority of large volume customers expressed some concerns about EGD. Of those, 24% mention high costs for new natural gas service, and 16% had meter reading accuracy. What steps is EGD taking to deal with these complaints, in particular, meter reading accuracy?

Response

Please see Exhibit I.STAFF.77.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Building Owners and Managers Association (BOMA)

Reference: Exhibit D1, Tab 1, p21

Question:

EGD has stated that the average business customer bill will have to increase by 3% per year starting 2019, until 2023, a total of 15% over the five year plan term. What is the equivalent percentage increase in EGD's delivery charge in 2019 and over the five year term? Approximately what percentage of the average total bill for each of residential, rate 6, GS, and large volume customers does the delivery charge represent?

Response

The rate impact in the customer engagement survey was based on a high level estimate at the time of the study. Please see below for the equivalent percentage increase in EGD's delivery charge for 2019 as filed in this application.

The Customer Bill Impacts for the EGD rate zone for 2019 are filed at Exhibit F1, Tab 1, Rate Order, Working Papers, Schedule 3 for all rate classes. Schedule 3, page 3 and 4 show the typical impacts for Rate 6 customers (average business customer), the delivery charge for 2019 is forecast to increase by approximately 1%.

For a typical residential sales service customer (Rate 1) consuming 2,400 m3 annually, the delivery charge represents approximately 53% of their total bill.

For a typical commercial sales service customer (Rate 6) consuming 22,606 m3, the delivery charge represents approximately 39% of their total bill.

For a typical large volume sales service customer (Rate 110) consuming 9,976,121 m3, the delivery charge represents approximately 14% of their total bill.

For 2020 to 2023, the applicant does not have the rate impact as the parameters underlying the rate setting mechanism are not known.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Building Owners and Managers Association (BOMA)

Reference: Exhibit D1, Tab 1, pp21-22

Question:

(a) Why was the increase expressed differently for each of the four cohorts?
(b) Please confirm that fewer than half of rate 6 and general service customers believe that the increase in bills of 3% annually for five years is reasonable or necessary, and that only 56% of large volume customers believe that raising rates by 1.5% annually for five years is reasonable or necessary.

Response

a) The increase is expressed differently to account for the different amount of natural gas consumed on average by the various customer groups.

b) Correct. To confirm fewer than half (44%) of Rate 6 customers believe that an increase in bills of 3% annually for five years is reasonable or necessary to maintain currently levels of safety and reliability. Also, slightly more than half (56%) of Large Volume customers believe that an increase in bills of 1.5% annually for five years is reasonable or necessary.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Building Owners and Managers Association (BOMA)

Reference: ROE

Question:

Please confirm that due to the timing of the studies, they did not ask questions about the impact of the federal carbon program.

Response

Confirmed. The studies did not ask questions about the impact of the federal carbon program.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Building Owners and Managers Association (BOMA)

Reference: Exhibit D1, Tab 1, pp 33

Question:

BOMA does not understand what the question on blending RNG is about. What is meant by "additional blending"?

Response

The previous question asked about a baseline blending amount for a fee, this follow-up question asked how much more customers would be willing to pay to blend more RNG into the system.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Building Owners and Managers Association (BOMA)

Reference: Exhibit D1, Tab 1, p42

Question:

For rate 6 customers, what would the increase in delivery charge be for 2019, and over the period 2019-2023, inclusive, at three volume/demand points, low, medium, and high?

Response

The rate impact in the customer engagement survey was based on a high level estimate at the time of the study. Please see below for the increase in EGD's delivery charge for 2019 as filed in this application.

Customer Bill Impacts for the EGD rate zone for 2019 are filed at Exhibit F1, Tab 1, Rate Order, Working Papers, Schedule 3 for all rate classes. Schedule 3, pages 3 and 4 show the typical impacts for Rate 6 customers (average business customer), the delivery charge for 2019 is forecast to increase by approximately 1% for a low, 1.6% for a medium and 1.8% for a large Rate 6 customer.

For 2020 to 2023, the applicant does not have the rate impact as the parameters underlying the rate setting mechanism are not known.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Building Owners and Managers Association (BOMA)

Reference: Exhibit D1, Tab 1, p44, Figure 31

Question:

Please confirm that only 16% of rate 6 customers would agree to pay 3% more on their gas bill to maintain existing level of reliability, safety, and service.

Response

In Figure 31, 11% of Rate 6 customers indicate that they would be willing to pay an additional 3% per month to maintain current levels of safety and reliability, an additional 12% of Rate 6 customers would be willing to pay an additional 7% per month to maintain safety and reliability and to invest in RNG.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Building Owners and Managers Association (BOMA)

Reference: Exhibit D1, Tab 1, p46

Question:

Please confirm that cost of gas was highest negative comments for rate 6 (residential) general service customers, and large volume customers.

Response

Correct, 9% of residential customers mention high cost / increasing price, which was also mentioned by 8% of Rate 6 Business customers 11% of General Service customers, and 6% of Large Volume customers.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Building Owners and Managers Association (BOMA)

Reference: Exhibit D1, Tab 1, p79

Question:

The diagram shows the capital (general plant maintenance) and IT upgrades. Why is "Other Capital" shown separately for System Integrity and Reliability?

Response

This diagram is to show that 90% of the EGD rate zone's capital investments are directly attributed to attaching new customers and maintaining a safe and reliable distribution system.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Building Owners and Managers Association (BOMA)

Reference: Exhibit D1, Tab 2, Schedule 1 (Innovative Research), p8

Question:

Please advise when the workbook was reviewed by intervenors, and which intervenors.

Response

A stakeholder session was held on January 23, 2017 to review the workbook. The following parties were invited to the session:

APPrO
Board Staff
BOMA
CCC
City of Kitchener
CME
Energy Probe
FRPO
IESO
IGUA
LPMA
OAPPA
OGVG
SEC
Six Nations
Shell
TransCanada
VECC

ENBRIDGE GAS INC.
Answer to Interrogatory from
Building Owners and Managers Association (BOMA)

Reference: Exhibit D1, Tab 2, Schedule 1 (Innovative Research), p10

Question:

Why were the categories somewhat reasonable or somewhat unreasonable introduced? Aren't prices either reasonable or unreasonable?

Response

The scale is used to capture the intensity of customer views. It is well established in the literature that people hold opinions with different levels of intensity. The more strongly someone holds a view, the more likely they are to act upon it. Since this is the case, Innovative's normal practice is to propose scales that capture intensity.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Building Owners and Managers Association (BOMA)

Reference: Exhibit B1, Tab 2, Schedule 1, pp4-5 of 36; ICM

Question:

(a) Please add a column for 2018 actuals to Tables 1 and 2.
(b) Please confirm that, for 2019, in Tables 1 and 2, the word "Budget" is equivalent to "Forecast".
(c) Comparing Tables 1 and 2, why is the EGD "Overhead" percentage of in-service capital much greater than Union, approximately one-third versus one-sixth, or twice as great a share of the total?

Response

a) Please see Exhibit I.LPMA.10.

b) Confirmed.

c) The capitalization process and composition of overheads differs between the EGD and Union rate zones. Both utilities follow the Enbridge Harmonized Enterprise-wide Capitalization Policy, however the overhead capitalization processes are still legacy based. A key difference is the use of burden rates. Union directly capitalizes labour (burdens) to capital projects whereas EGD treats these costs as overheads (DLC, or Departmental Labour Costs). Please refer to Exhibit I.STAFF.32 (c) for an explanation of the components of overheads.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Building Owners and Managers Association (BOMA)

Reference: Exhibit B1, Tab 2, Schedule 1, p12

Question:

Please provide the calculation of the 1.07% price cap index. Please confirm that for EGD, 1.07% is not an average but simply the index based on the inflation forecast less the productivity factors for 2019.

Response

Please see Exhibit B1, Tab 1, Schedule 1, page 4, Table 2 and Table 3 for the calculation of the Price Cap Index.

Confirmed. The 1.07% PCI for EGD is based on the inflation forecast less the productivity and stretch factors for 2019.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Building Owners and Managers Association (BOMA)

Reference: Exhibit B1, Tab 2, Schedule 1, p10

Question:

Please provide the calculation for Union rate base of 5,331, showing for each year from 2013 through 2019 the rate base and depreciation associated with capital pass-through treatment in each year of that period.

Response

Exhibit B1, Tab 2, Schedule 1, page 16, Table 6, Lines 2 to 4 provides a breakdown of the Union rate zone ICM Threshold rate base and depreciation amounts. Both the rate base and depreciation values are calculated by adding the Union 2013 Board-approved values, to the 2019 proposed/forecast capital pass-through values. Attachment 1 to this response provides the rate base and depreciation amounts for capital pass-through projects, for 2013 to 2019.

Table 1
Capital Pass-Through Rate Base and Depreciation (2013-2019)
($000's)

	2013 Actual		2014 Actual (1)		2015 Actual (2)		2016 Actual (3)		2017 Actual (4)		2018 Actual (5)		2019 Proposed (6)	
Capital Pass-Through Project	**Rate Base**	**Depreciation**	**Rate Base**	**Depreciation**	**Rate Base**	**Depreciation**	**Rate Base**	**Depreciation**	**Rate Base**	**Depreciation**	**Rate Base**	**Depreciation**	**Rate Base**	**Depreciation**
Parkway West	-	-	12,200	578	103,750	3,071	215,846	5,185	217,523	5,415	213,974	5,479	210,033	5,508
Brantford to Kirkwall/Parkway D	-	-	-	-	24,171	2,364	185,273	4,857	187,254	4,990	182,727	4,995	177,700	4,995
2016 Dawn-Parkway Expansion Project	-	-	-	-	2,259	176	64,092	4,066	328,149	8,030	329,689	8,255	323,388	8,261
Burlington to Oakville Project	-	-	-	-	-	-	15,902	821	78,870	1,668	79,289	1,720	78,277	1,732
2017 Dawn-Parkway Expansion Project	-	-	-	-	-	-	18,368	1,225	258,892	8,975	569,940	16,035	583,664	17,306
Panhandle Reinforcemet Project	-	-	-	-	-	-	-	-	22,610	2,027	203,412	4,473	223,844	4,939
Total	-	-	12,200	578	130,180	5,611	499,481	16,154	1,093,298	31,105	1,579,031	40,957	1,596,906	42,741

Notes:
(1) EB-2015-0010, Exhibit A, Tab 1, p. 32.
(2) EB-2015-0118, Exhibit A, Tab 1, pp. 34, 41, 50.
(3) EB-2017-0091, Exhibit A, Tab 1, pp. 30, 38, 49, 56, 61.
(4) EB-2018-0105, Exhibit A, Tab 1, pp. 30, 37, 46, 53, 60, 66.
(5) Actual 2018 Rate Base and Depreciation figures are expected to be included in the Application and Evidence for the EGI 2018 Deferrals and Earnings Sharing proceeding, but are draft at this time and may change.
(6) Proposed in EB-2018-0305, Exhibit F1, Tab 2, Rate Order, Working Papers, Schedule 16, pp 4-5.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Building Owners and Managers Association (BOMA)

Reference: Exhibit B1, Tab 2, Schedule 1, p9

Question:

Please provide separate calculations which show what the Union 2019 rate base and depreciation would be if all additions to rate base and depreciation for each year from 2013 through to 2019 were added to 2013 rate base and depreciation , and show what the eligible ICM capacity would be, if that were done.

Response

The use of ICM was subject to litigation in the MAADs and Rate Setting Mechanism proceeding, and made available to EGD and Union as part of the Board's Decision and Order dated August 30, 2018. As per the decision, the Board ordered Enbridge Gas to add the rate base and depreciation associated with capital pass-through projects to the 2013 OEB-approved rate base and depreciation in determining the eligible incremental capital amount for Union.

Enbridge Gas declines to provide the calculation as it is not in accordance with the Board's MAADs decision, and it does not represent what current rates can support.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Building Owners and Managers Association (BOMA)

Reference: Exhibit B1, Tab 2, Schedule 1, p10

Question:

Are EGD and Union seeking approval for all its "ICM projects" planned for the term of the Agreement, or only the 2019 assets in-service in 2019? Please discuss.

Response

As per the MAADs Decision, the Board approved an ICM mechanism for Enbridge Gas to seek rate recovery for incremental capital during the deferred rebasing term. As part of this rate application, Enbridge Gas is seeking approval for ICM rate recovery associated with 2019 in-service projects which includes the NPS 30 Don River Replacement project, Sudbury Replacement project, Kingsville Transmission Reinforcement project, and Stratford Reinforcement project.

For any future ICM projects, Enbridge Gas will seek the Board's approval for ICM rate recovery as part of its annual rate applications, if it determines that these projects are eligible for incremental funding as per the MAADs Decision and the Board's ICM policy.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Building Owners and Managers Association (BOMA)

Reference: Exhibit B1, Tab 2, Schedule 1, p19

Question:

(a) Please provide the revenue requirement impact of:
    (i) the Sudbury Replacement Project for each year of the deferral rebasing period 2019-2023;
    (ii) the historical spend on the Sudbury Replacement Project in each year since it received Leave to Construct approval, and a copy of the Board's Leave to Construct decision.
(b) When was the Sudbury Leave to Construct filed; approved?

Response

(a) (i) Please see Exhibit B1, Tab 2, Schedule 1, page 31, Table 11, Line No. 2 for the revenue requirement on Sudbury Replacement project. A further breakdown of the revenue requirement can be found at Exhibit B1, Tab 2, Schedule 1, Appendix E, page 2.

(ii) Please see Exhibit I.BOMA.37 for historical spend information. A copy of the Board's Leave to Construct decision can be found at Attachment 1.

(b) The Sudbury Leave to Construct, EB-2017-0180 was filed on May 5, 2017 and approved on September 28, 2017.

Ontario

Ontario Energy Board
Commission de l'énergie de l'Ontario

DECISION AND ORDER

EB-2017-0180

UNION GAS LIMITED

Application for approval to construct a natural gas pipeline in the City of Greater Sudbury

BEFORE: Lynne Anderson
Presiding Member

September 28, 2017

TABLE OF CONTENTS

INTRODUCTION

On May 5, 2017, Union Gas Limited (Union Gas) applied to the Ontario Energy Board (OEB) under section 90(1) of the Ontario Energy Board Act, 1998 for an approval of its proposal to build 20 km of NPS 12 hydrocarbon (natural gas) pipeline in the Sudbury area (the Proposed Pipeline). This Proposed Pipeline would replace two sections of NPS 10 pipeline in the City of Greater Sudbury. A map of the facilities is included as Attachment A.

Union Gas stated that the Proposed Pipeline is needed because its Integrity Management Program has identified multiple integrity issues through inspections and investigative digs. The current pipeline was predominately constructed in 1958. Union Gas proposed to increase the size of the pipeline to 12 inches (NPS 12) to provide capacity for future growth on the Sudbury system.

Union Gas stated in its application that the Proposed Pipeline was the continuation of three previous pipeline replacement projects in the Sudbury area (Sudbury Replacement Projects) previously approved by the OEB[1] . One issue that arose is whether the Proposed Pipeline should be NPS 12 in size rather than NPS 10, the size of the existing pipeline. The OEB is granting leave to construct the NPS 12 pipeline proposed by Union Gas, but has noted that Union Gas could improve future applications by providing the OEB with a forecast of growth to support the upsizing of any pipelines, as well as information on the longer-term plans for supply to an area in order to provide context for individual projects. Leave is granted under section 90(1) of the OEB Act for the Proposed Pipeline. For the reasons set out in this Decision and Order, the OEB finds that the construction of the Proposed Pipeline is in the public interest.

[1] EB-2015-0042, EB-2016-0122 and EB-2016-0222

THE PROCESS

The OEB issued a Notice of Application (Notice) on June 8, 2017*.* Union Gas published and served the Notice as directed by the OEB. The Notice was served to all directly affected landowners and encumbrancers; the clerks of the City of Greater Sudbury; Indigenous communities with lands or interest in the lands directly affected by the Proposed Pipeline; the Métis Nation of Ontario; all affected utilities and railway companies; members of the Ontario Pipeline Coordinating Committee (OPCC); and the Sudbury Conservation Authority. Union Gas published the English and French versions of the Notice in the Sudbury Star and Sudbury Le Voyageur, and posted the Notice on its website.

Union Gas requested that this application be determined by way of a written hearing. The Notice of Hearing for this application set a June 26, 2017 deadline for requests for intervenor status and for any requests for an oral hearing. The OEB received no requests for intervenor status, or requests for an oral hearing, The OEB did not receive any letters of comment in respect of this application.

The OEB issued Procedural Order No. 1 on July 7, 2017, setting the schedule for written interrogatories and written submissions. Union Gas filed responses to OEB staff interrogatories on July 25, 2017. According to Procedural Order No. 1, the submission from OEB staff was due by August 9, 2017, and Union Gas' reply submission, if any, was due by August 16, 2017. However, in response to OEB staff interrogatory no. 6, Union Gas indicated that it was awaiting a letter from the Ministry of Energy (MoE) to inform Union Gas if there was a duty to consult, as well as to provide the MoE's comments regarding the consultation activities that Union Gas had completed and further consultation that was proposed.

According to section 3.3 of the OEB *Environmental Guidelines for the Location, Construction and Operation of Hydrocarbon Pipelines and Facilities in Ontario* (OEB Environmental Guidelines), the MoE is to provide a letter to the applicant expressing its view on the adequacy of the Indigenous consultation prior to the record being closed by the OEB for a leave to construct proceeding.

By August 8, 2017 the OEB had not received the letter from the Ministry referred to in Union Gas' response to interrogatory no. 6. For this reason, the OEB issued a letter dated August 8, 2017, cancelling the remaining schedule set in Procedural Order No. 1, and advising that, "the new schedule for the balance of this proceeding will be issued after the OEB receives complete documentation on the Indigenous consultation activities as required by the OEB Environmental Guidelines."

On August 11, 2017, Union Gas filed a letter from the MoE dated August 10, 2017 advising that "the Ministry is of the opinion that the procedural aspects of consultation undertaken by Union Gas to date for the purpose of the Ontario Energy Board's leave to construct is satisfactory".

Union Gas also filed an update to the version of the Indigenous consultation log filed in its response to OEB staff interrogatories. Union Gas' August 11, 2017 filings completed the evidentiary record for this proceeding. The OEB issued Procedural Order No. 2 to set the dates for an OEB staff written submission and written reply submission by Union Gas. OEB staff filed written submissions on August 25, 2017 and Union Gas filed a reply submission on September 1, 2017. This concluded the record for the proceeding.

STRUCTURE OF THE DECISION

This is an application under section 90 of the OEB Act seeking an order for leave to construct a natural gas pipeline. Section 96 of the Act provides that the OEB shall make an order granting leave if the OEB finds that “the construction, expansion or reinforcement of the proposed work is in the public interest”. When determining whether a project is in the public interest, the OEB typically examines the need for the project and alternatives, the project’s economics and rate impacts, the environmental impacts, land matters, design and safety requirements, and consultation with Indigenous communities.

This Decision and Order is structured by each of these issues.

NEED FOR THE PROJECT AND ALTERNATIVES

Union Gas stated in its application that the Proposed Pipeline was the continuation of three previous pipeline replacement projects in the Sudbury Area (Sudbury Replacement Projects) previously approved by the OEB[2]. OEB staff asked questions about why Union Gas did not file a single application for each of these projects. Union Gas responded that there could not have been a single application because there were specific requirements for each individual case.

The existing pipeline in question was predominately constructed in 1958. Union Gas did inspections of the existing pipeline in 2002 and again in 2006/2007 and 2014/2015. Union Gas stated that the pipeline continues to deteriorate due to corrosion and denting. Cathodic protection is used to reduce corrosion, but Union Gas has stated that it is difficult to maintain because of the pipeline's location in both granite bed rock and low lying swamps.

Union Gas is also proposing to increase the size of the pipeline from 10 inches to 12 inches (NPS 10 to NPS 12) in this replacement project. According to Union Gas, this would increase the capacity of the Sudbury Lateral System by 5% at an incremental cost of $1.5M (approximately a 2% increase to the cost forecast).

Union Gas did not provide a load forecast for the Sudbury area in its application. In response to interrogatories, Union Gas provided a general service growth forecast of 1400 m^3/hr/year and stated that the incremental capacity of moving from a 10 inch pipe to a 12 inch pipe would be utilized within 8 years based on this forecast. In its reply submission, Union Gas provided a table with a load forecast to demonstrate that the capacity of the pipelines in the Sudbury area would reach capacity in 2026/2027, even with the Proposed Pipeline. Since these details were only available at the time of the reply submission, there was no opportunity for OEB staff to ask questions or comment on this forecast.

Union Gas also stated that while it had not determined the impacts of the Cap and Trade program on its facilities, there was an expectation that annual customer usage would decline but peak hour demands may not. Union Gas designs its systems based on peak hour demands, the maximum amount of natural gas the pipeline needs to carry in peak periods.

[2] EB-2015-0042, EB-2016-0122 and EB-2016-0222

Findings

The OEB accepts Union's evidence that the project is needed to maintain a safe and secure supply of gas in the Sudbury area. The pipeline is nearly 60 years old and Union has stated that its inspections have uncovered integrity issues.

The OEB accepts Union Gas' proposal to use 12 NPS pipeline for the Proposed Pipeline. While Union Gas did not provide a customer and volume forecast to be tested as part of its application, the incremental cost of the 12 NPS pipe over the 10 NPS is forecast to be $1.5M, a 2% increase in the cost of project. This is expected to increase the capacity of the Sudbury Lateral System by 5%. If Union Gas' volume forecast is accurate, installing NPS 12 pipe now will be the lowest cost option to meet the capacity requirement in the Sudbury area. The OEB notes that the accuracy of Union Gas' current forecasts can be tested in a future rate application when the rates are sought to recover the cost of the Proposed Pipeline. The OEB has also approved the use of NPS 12 in previous applications for pipelines in the Sudbury area.

The OEB accepts that Union Gas has not yet determined the impact of the cap and trade program on its facilities at this time as the program is still new. In the future, if Union Gas is proposing that a pipeline be upsized to support growth, it should provide a forecast of that growth in its application.

With respect to the coordination of multiple projects into a single application, this is the preferred approach whenever possible so the OEB can consider the overall plan for supply to an area when assessing each project. The OEB understands that all of the details required for a leave to construct application might not be available to file a comprehensive application for multiple projects in an area at the same time. There is an expectation, however, that utilities file information to provide context to each application. Robust planning and asset management is a key element of the OEB's Renewed Regulatory Framework. System integrity was an issue in the recent Sudbury Replacement Projects. Union Gas' Integrity Management Program should be developing at least a five year plan for facility replacements to be included in a comprehensive asset management plan. On this basis, when an application for a pipeline replacement in an area is filed, Union Gas can provide details of other planned projects in the area to provide the appropriate context for considering each application.

PROJECT ECONOMICS AND RATE IMPACTS

Union Gas considered two other alternatives: Replace the existing pipe with another pipe of the same size (NPS 10), or only replace those segments of the pipeline identified as having integrity concerns.

The proposed project is forecast to cost approximately $74M. This is in the range of 29%-64% higher cost per metre than the recent Sudbury Replacement Projects[3]. Union Gas has stated the Proposed Pipeline has large proportions of rock excavation, wetland management, specialized cathodic protection design and bypass installations that were not present to the same extent in other Sudbury replacement projects. In addition, Union Gas estimated in its interrogatory responses that the cost of managing known integrity issues in this section of the Sudbury system is $8 to $10M over the next several years and that these issues will be addressed with the Proposed Pipeline.

Union Gas is not seeking approval of the cost consequences of the Proposed Pipeline in this proceeding and it did not provide estimated bill impacts to customers. Union Gas has indicated that it will seek cost recovery of the Proposed Pipeline as part of its 2019 rates application.

Findings

The use of NPS 12 pipe was discussed earlier in this Decision and Order. Given the age of the existing pipeline, the OEB accepts Union Gas' explanation for why it did not propose the option to replace only sections of the existing pipeline. The OEB therefore approves the option selected by Union Gas for the Proposal Pipeline.

The OEB finds that the cost estimates are acceptable to address potential safety and security issues from the existing pipeline. In 2013, the OEB approved a rate base for Union Gas of $3.7B[4]. This project at $74M is material, but is not expected to result in an unreasonable rate impact to customers when depreciated over the typical 50 year period.

The OEB expects to review the costs of the Proposed Pipeline in a future rate application at which time the OEB will be able to assess the actual costs for the project.

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[3] OEB Staff interrogatory #3
[4] This rate base was approved in the OEB's Decision EB-2011-0210 on Union Gas' Cost of Service rates application.

ENVIRONMENTAL ASSESSMENT

As required by the OEB's Environmental Guidelines, Union Gas had an Environmental Report (ER) prepared for the Proposed Pipeline. The ER was provided to members of the OPCC. No concerns were raised by the OPCC.

OEB staff asked questions about safety measures for blasting and hoe-ramming of rocks and the methods for dewatering of swamps and wet areas. Union Gas committed to following applicable provincial standards: Specification, OPSS.MUNI 120 General Specification for the Use of Explosives; Ontario Provincial Standard Specification, OPSS.ROV 120 General Specification for the Use of Explosives; and Guidelines for the Use of Explosives In or Near Canadian Fisheries Waters. In addition, Union Gas will follow its own procedures and specifications. This will include the hiring of a blasting consultant to work with its contractor in developing a blasting plan.

Findings

The OEB finds that Union Gas has adequately addressed the environmental issues through its proposed mitigation measures and its commitment to implement recommendations in the Environmental Report.

LAND MATTERS

Based on Union Gas evidence, there are 77 properties directly affected by the Proposed Pipeline. While existing easements will be used where possible, numerous new easements are being obtained. Union Gas has also stated that numerous temporary easements will be required from 61 properties.

Union Gas also plans to use road allowances. Union Gas has a franchise agreement with the City of Greater Sudbury that establishes, among other things, the terms and conditions of using road allowances for natural gas pipelines.

In its reply submission Union Gas provided an update that 57% of the necessary land rights are in place.

Per section 97 of the *OEB Act*, leave to construct cannot be granted until an OEB-approved form of agreement has been offered to landowners. Union Gas filed in its application a copy of the form of easement agreement that has been provided to property owners for the OEB's approval. Union Gas submitted that this is the same form of agreement approved by the OEB in the recent Union Gas Panhandle Reinforcement proceeding[5] . OEB staff agreed with Union Gas that the form of agreement is consistent with past OEB approved agreements.

Findings

The OEB is satisfied that Union Gas is addressing land matters appropriately and the OEB approves the form of agreement offered to landowners. The OEB notes that it is the form of agreement that is approved by the OEB and that the content of each clause may be amended by mutual agreement between parties through further negotiations.

[5] EB-2016-0186

DESIGN AND SAFETY REQUIREMENTS

Union Gas has stated that the new pipeline will be constructed to meet or exceed the requirements of CSA Code Z662-15 Standard and will be designed and constructed in accordance with *Ontario Regulation 210/01* and the *Technical Standards and Safety Act 2000, Oil and Gas Pipeline Systems*. Union Gas also stated that the pipe used for the Proposed Pipeline will be manufactured to CSA Z245, 1-14 Steel Pipe Standard.

For any pipe to be abandoned in place, Union Gas has stated that it will follow the TSSA Abandonment Guidelines.

The Technical Standards and Safety Authority (TSSA) was served notice of this application as part of the OPCC. No concerns were raised.

Findings

The OEB finds that Union Gas has provided adequate evidence to confirm that the proposed facilities will be designed and constructed in accordance with current technical and safety requirements.

The OEB finds that Union Gas has provided adequate evidence to confirm that the existing facilities will be abandoned in accordance with current technical and safety requirements.

CONSULTATION WITH INDIGENOUS COMMUNITIES

Notice of this proceeding was provided to all potentially impacted Indigenous communities. As detailed in the materials filed with the OEB, Union Gas has conducted various meetings, open houses, and other communications with a number of Indigenous communities. Summaries of these meetings were filed as part of the record. Union Gas has committed to continuing this dialogue as the project progresses, and the OEB is not aware of any significant concerns about the project. No Indigenous communities sought to intervene in this proceeding.

During construction, Union Gas has committed to having staff in the field to meet with Indigenous organizations to discuss and review any issues. Union Gas will also consult with and provide the results of any archaeological assessments for the project to any Indigenous group upon their request.

The Ministry of Energy (MoE) sent a letter to Union Gas on August 10, 2017 advising that "the Ministry is of the opinion that the procedural aspects of consultation undertaken by Union Gas to date for the purposes of the Ontario Energy Board's Leave to Construct is satisfactory."

The MoE also asked that Union Gas continue to dialogue with the Atikameksheng Anishnawbek First Nation about the community's concerns and to keep the MoE informed about upcoming meetings with the Wahnapitae First Nation and Atikameksheng Anishnawbek First Nation. Union Gas agreed to undertake these meetings and keep the MoE and OEB informed of the outcomes.

Findings

The OEB is satisfied that the duty to consult has been adequately discharged up to this stage of the project. The OEB expects Union Gas meet its commitments to the MoE and to continue to work closely with any potentially impacted Indigenous communities as the project moves forward.

CONDITIONS OF APPROVAL

OEB staff proposed a number of conditions of approval for the Proposed Pipeline based on conditions approved by the OEB for similar projects. Union Gas stated that it can accept the conditions proposed by OEB staff.

The OEB approves the conditions of approval proposed by OEB staff for this project, which are provided in Attachment B.

CONCLUSION

The OEB finds that the Proposed Pipeline serves the public interest. The OEB accepts Union Gas' evidence that the project is needed to maintain a safe and secure supply of gas to the area.

The OEB approves the form of agreement offered to landowners by Union Gas pursuant to section 97 of the Act.

The MoE provided an opinion that Union Gas' consultation described in its Indigenous Consultation Report has been satisfactory. The OEB is satisfied that the duty to consult has been sufficiently discharged for the Proposed Pipeline as of the time of this approval.

The OEB notes that Union Gas is responsible for obtaining all necessary approvals, such as permits, licences, certificates, land agreements including agreements pertaining to access roads construction and removal, connection agreements and easement rights required to construct, operate and maintain the Proposed Pipeline, at such time(s) as they may be necessary.

ORDER

THE ONTARIO ENERGY BOARD ORDERS THAT:

1. Union Gas Limited is granted leave, pursuant to subsection 90(1) of the OEB Act, to construct 20 km of NPS 12 hydrocarbon (natural gas) pipeline to replace the existing pipeline segments in the City of Greater Sudbury, as described in its application. Leave to construct is subject to the Conditions of Approval set forth in Attachment B.

2. Union Gas Limited shall pay the OEB's costs incidental to this proceeding upon receipt of the OEB's invoice.

DATED at Toronto September 28, 2017

ONTARIO ENERGY BOARD

Original signed by

Kirsten Walli
Board Secretary

ATTACHMENT A

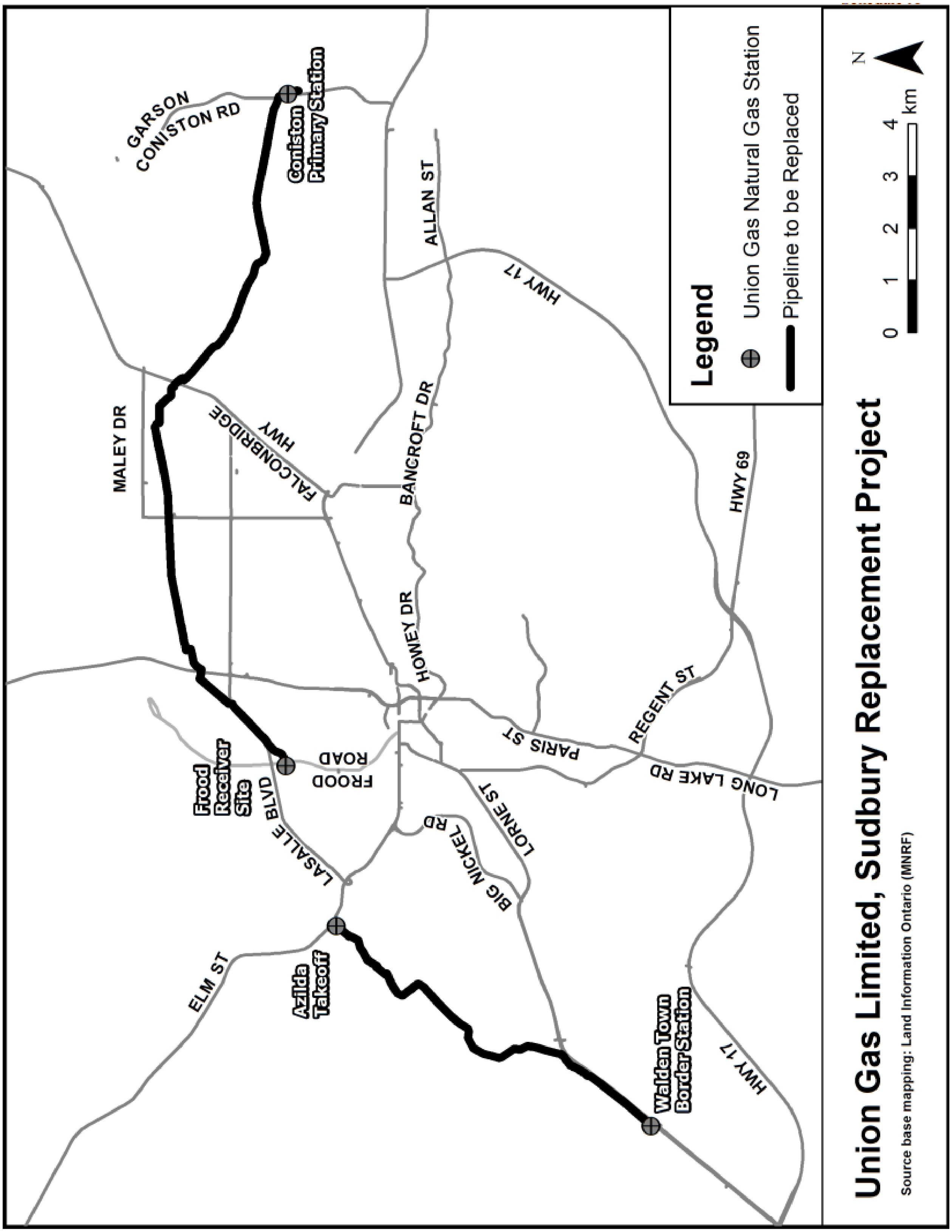
MAP OF FACILITIES

DECISION AND ORDER

UNION GAS LIMITED

EB-2017-0180

SEPTEMBER 28, 2017



Union Gas Limited, Sudbury Replacement Project

Source base mapping: Land Information Ontario (MNRF)

ATTACHMENT B

CONDITIONS OF APPROVAL

DECISION AND ORDER

UNION GAS LIMITED

EB-2017-0180

SEPTEMBER 28, 2017

Leave to Construct Conditions of Approval

Union Gas Limited

EB-2017-0180

1. Union Gas Limited (Union Gas) shall construct the facilities and restore the land in accordance with the OEB's Decision and Order in EB-2017-0180 and these Conditions of Approval.

2. (a) Authorization for leave to construct shall terminate 12 months after the decision is issued, unless construction has commenced prior to that date.

   (b) Union Gas shall give the OEB notice in writing:
   i. of the commencement of construction, at least ten days prior to the date construction commences;
   ii. of the planned in-service date, at least ten days prior to the date the facilities go into service;
   iii. of the date on which construction was completed, no later than 10 days following the completion of construction; and
   iv. of the in-service date, no later than 10 days after the facilities go into service.

3. Union Gas shall implement all the recommendations of the Environmental Report filed in the proceeding, and all the recommendations and directives identified by the Ontario Pipeline Coordinating Committee review.

4. Union Gas shall advise the OEB of any proposed change to OEB-approved construction or restoration procedures. Except in an emergency, Union Gas shall not make any such change without prior notice to and written approval of the OEB. In the event of an emergency, the OEB shall be informed immediately after the fact.

5. Union Gas shall file, in the proceeding where the actual capital costs of the project are proposed to be included in rate base, a Post Construction Financial Report, which shall indicate the actual capital costs of the project and shall provide an explanation for any significant variances from the cost estimates filed in this proceeding.

6. Both during and after construction, Union Gas shall monitor the impacts of construction, and shall file with the OEB one paper copy and one electronic (searchable PDF) version of each of the following reports:
   a) A post construction report, within three months of the in-service date, which shall:
      i. provide a certification, by a senior executive of the company, of Union Gas' adherence to Condition 1;
      ii. describe any impacts and outstanding concerns identified during construction;
      iii. describe the actions taken or planned to be taken to prevent or mitigate any identified impacts of construction;
      iv. include a log of all complaints received by Union Gas, including the date/time the complaint was received, a description of the complaint, any actions taken to address the complaint, the rationale for taking such actions; and
      v. provide a certification, by a senior executive of the company, that the company has obtained all other approvals, permits, licenses, and certificates required to construct, operate and maintain the proposed project.

   b) A final monitoring report, no later than fifteen months after the in-service date, or, where the deadline falls between December 1 and May 31, the following June 1, which shall:
      i. provide a certification, by a senior executive of the company, of Union Gas' adherence to Condition 3;
      ii. describe the condition of any rehabilitated land;
      iii. describe the effectiveness of any actions taken to prevent or mitigate any identified impacts of construction;
      iv. include the results of analyses and monitoring programs and any recommendations arising therefrom; and
      v. include a log of all complaints received by Union Gas, including the date/time the complaint was received; a description of the complaint; any actions taken to address the complaint; and the rationale for taking such actions.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Building Owners and Managers Association (BOMA)

Reference: Exhibit B1, Tab 2, Schedule 1, p20

Question:

Please provide, for both EGD and Union, the actual ROEs from 2013 through 2018, relative to the Board approved ROE for each of those years.

Response

Please see Exhibit I.BOMA.38.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Building Owners and Managers Association (BOMA)

Reference: Exhibit B1, Tab 2, Schedule 1, p20

Question:

Please confirm that the Advanced Capital Module (EB-2014-0219) defined ICM/ACM projects as being discrete, incremental, material, and not part of utilities' typical annual capital programs.

Response

Confirmed.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Building Owners and Managers Association (BOMA)

Reference: Exhibit B1, Tab 2, Schedule 1, p24

Question:

Please provide the reason for the increase in the cost of the Don River from $25.6M (LTC) to $34.2M in Table 8, p18 of 36.

Response

Please see Exhibit I.STAFF.25, part (a).

ENBRIDGE GAS INC.
Answer to Interrogatory from
Building Owners and Managers Association (BOMA)

Reference: Exhibit B1, Tab 2, Schedule 1, p24

Question:

Please provide the revenue requirement impact of the Don River Replacement for each year of 2019-2023.

Response

Please refer to Exhibit B1, Tab 2, Schedule 1, page 31, Table 11, Line No. 1. A further breakdown of the revenue requirement can be found at Exhibit B1, Tab 2, Schedule 1, Appendix E, page 1.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Building Owners and Managers Association (BOMA)

Reference: Exhibit B1, Tab 2, Schedule 1, p24

Question:

Please provide the assets in-service for the Don River project for each of the years 2017, 2018, and 2019, through until 2023. Have there been any changes to the forecast December 2019 in-service date?

Response

The existing NPS 30 Don River Bridge crossing was in-service through 2017, 2018 and will continue to be in-service in 2019 until it is abandoned after the new NPS 30 pipe replacement project is completed and in-service.

There has been no change to the forecasted December 2019 in-service date for the Don River Replacement project.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Building Owners and Managers Association (BOMA)

Reference: Exhibit B1, Tab 2, Schedule 1, p25

Question:

(a) Please provide a detailed breakdown of the cost increase to $95.3M from the Leave to Construct filing budget of $74.1M, approximately a 30% increase.

(b) Please provide the priority of the Sudbury project with the Union 2018 and 2019 capital budget. Please provide a prioritized list of Union 2018 capital projects.

Response

(a) Please see Exhibit I.EP.16.

b) The Sudbury project was identified as a Risk Ranked II project as per the criteria outlined in the Risk Analysis section, page 53 of Union rate zones' AMP, filed at Exhibit C1, Tab 3, Schedule1. Union uses a simple priority ranking scale of 1 to 4 to help to organize the entire capital portfolio and to ensure that the highest priority work is identified and planned accordingly. The Sudbury project is a Priority Level 2 based on the "Priority Ranking Scale" criteria provided on Table 4.2.1.1.4.1, page 53 in Union rate zones' AMP.

Enbridge Gas has attached a listing of all projects for 2018 for the Union rate zone. This listing includes the following information:

- Asset Category
- Portfolio
- Project Name
- Priority
- Project Cost

Project Listing for Union Rate Zone 2018

Asset Category	Portfolio	Description	Priority	2018
Compression & Dehy	Compression & Dehy	Absent Tank Installs - Various	1	$ 321,071.50
Compression & Dehy	Compression & Dehy	STO Cathodic Protection	1	$ 117,213.40
Compression & Dehy	Compression & Dehy	STO - HPC D/L/B/P/H	1	$ 400,000.00
Compression & Dehy	Compression & Dehy	Payne Compressor Engine Overhaul	2	$ 761,382.60
Compression & Dehy	Compression & Dehy	Tecumseh UPS Upgrade	2	$ 88,561.06
Compression & Dehy	Tools	STO COMPRESSOR EAST TOOL ADDITIONS	2	$ 66,282.00
Compression & Dehy	Tools	STO CAPITAL TOOLS ADDITIONS - COMP WEST	2	$ 66,282.00
Compression & Dehy	Tools	STO CAPITAL TOOLS ADDITIONS -TECHNICIANS	2	$ 22,094.00
Compression & Dehy	Tools	STO CAPITAL TOOLS ADDITIONS - Mech	2	$ 22,094.00
Compression & Dehy	Tools	STO CAPITAL TOOLS REPL - TECH WEST	2	$ 22,094.00
Compression & Dehy	Tools	STO CAPITAL TOOLS REPL - Mech	2	$ 22,094.00
Compression & Dehy	Compression & Dehy	Dawn - UPS Battery replacements	3	$ 23,724.40
Compression & Dehy	Compression & Dehy	LBP - UPS Battery replacements	3	$ 23,724.40
Compression & Dehy	Compression & Dehy	Remotes - UPS Battery replacements	3	$ 23,724.40
Compression & Dehy	Compression & Dehy	Oil Springs E Water Jacket/Coolers	2	$ 1,050,406.60
Compression & Dehy	Compression & Dehy	STO - PLC5 upgrade to ControlLogix	3	$ 320,504.07
Compression & Dehy	Compression & Dehy	Bright B - Vibration monitor	3	$ 79,367.00
Compression & Dehy	Compression & Dehy	Lobo B MCC replacement	3	$ 166,927.80
Compression & Dehy	Compression & Dehy	Bright B MCC replacement	3	$ 166,927.80
Compression & Dehy	Compression & Dehy	Dawn D Lube Oil Skid Repalcement	3	$ 214,033.00
Compression & Dehy	Compression & Dehy	Dawn Dehydration Plant Glycol Filtration	3	$ 249,556.10
Compression & Dehy	Compression & Dehy	Dawn Auxillary Building 2 Boiler Replace	3	$ 179,536.85
Compression & Dehy	Compression & Dehy	LOBO A1 - Fire/Gas Detection Panel	3	$ 112,089.20
Compression & Dehy	Compression & Dehy	LOBO A2 - Fire/Gas Detection Panel	3	$ 112,089.20
Compression & Dehy	Compression & Dehy	Lobo A1 & A2 Avon Ext Soak Wash System	*	$ 100,000.00
Compression & Dehy	Compression & Dehy	STO - Parkway Safety and Security Upgrad	*	$ 50,000.00
Compression & Dehy	Compression & Dehy	STO-Safety & Security Upgrades-Various	*	$ 75,000.00
Compression & Dehy	Compression & Dehy	STO - LED Lighting Upgrade	*	$ 152,163.20
Compression & Dehy	Compression & Dehy	STO - LED Lighting Upgrade- Eastern Comp	*	$ 86,607.45
Compression & Dehy	Compression & Dehy	GC BUILDING Gas Detection Replacement	*	$ 66,907.36
Compression & Dehy	Compression & Dehy	STO - Gas Chromatograph	*	$ 198,756.70
Compression & Dehy	Compression & Dehy	STO - Comp E Blowdown Stack Fencing	*	$ 50,000.00
Compression & Dehy	Compression & Dehy	STO - Hagar Non Cres Building Upgrades	*	$ 50,000.00
Compression & Dehy	Compression & Dehy	STO DAWN YARD PAVING and TRENWAY REPLACE	*	$ 100,000.00
Compression & Dehy	Compression & Dehy	Edy's Mills - Dehydration facility aband	*	$ 157,477.40
Fleet	Fleet	OS - Transportation-Replacements	1	$ 12,000,000.00
IT	IT	Contrax Modernization **C/O 2017**	1	$ 12,578,697.44
IT	IT	Service Suite Lifecycle C/O 2017	1	$ 7,799,479.50
IT	IT	IS Business Support	1	$ 2,400,090.04
IT	IT	IS Projects	1	$ 1,599,350.83
IT	IT	SCADA	1	$ 797,955.25
IT	IT	IT Services	1	$ 3,062,358.38
LNG	Tools	STO CAPITAL TOOLS ADDITIONS - HAGAR LNG	2	$ 22,094.00

Asset Category	Portfolio	Description	Priority	2018
LNG	Tools	STO CAPITAL TOOLS REPL - HAGAR LNG	2	$ 22,094.00
LNG	LNG	Hagar LNG Piping Support Sys &Insulation	3	$ 250,000.00
LNG	LNG	Hagar Valve Replacements	3	$ 159,646.20
LNG	LNG	Hagar - Firefighting equipment	3	$ 43,083.29
Measurement	Lab Upgrades	ENG - LAB FACILITIES UPGRADE	1	$ 70,000.00
Measurement	Odorant Upgrade	ENG - Odourant Upgrade	1	$ 600,000.00
Measurement	Turbo Corrector Upgrades	ENG - Turbo Corrector Upgrade	2	$ 58,846.65
Measurement	Replacement of Obsolete RTUs	ENG -Bristol 3330 Replacement Program	3	$ 1,426,057.81
Measurement	Industrial Billing - Cell Upgrade	ENG Industrial Billing Cell Upgrade	*	$ 96,883.00
Measurement	Tools	ENG -Technician Tools Additions	2	$ 50,000.00
Measurement	Turbine Meter Auto-Oilers	ENG -Turbine Meter Automatic Oilers	2	$ 33,669.60
Measurement	Labour Cost for exchanges (maint.)	Meter & Regulator Inst Repl-Company	1	$ 730,658.09
Measurement	Labour Cost for exchanges (maint.)	Meter & Regulator Inst Repl-Company	1	$ 360,937.02
Measurement	Labour Cost for exchanges (maint.)	Meter & Regulator Inst Repl-Company	1	$ 1,263,731.10
Measurement	Labour Cost for exchanges (maint.)	Meter & Regulator Inst Repl-Company	1	$ 591,864.12
Measurement	Labour Cost for exchanges (maint.)	Meter & Regulator Inst Repl-Company	1	$ 1,178,899.00
Measurement	Labour Cost for exchanges (maint.)	Meter & Regulator Inst Repl-Company	1	$ 537,665.97
Measurement	Labour Cost for exchanges (maint.)	Meter & Regulator Inst Repl-Company	1	$ 449,745.73
Measurement	Labour Cost for exchanges (maint.)	Meter & Regulator Inst Repl-Company	1	$ 1,049,332.32
Measurement	Labour Cost for exchanges (maint.)	Meter & Regulator Inst Repl-Company	1	$ 505,436.31
Measurement	Labour Cost for exchanges (maint.)	Meter & Regulator Inst Repl-Company	1	$ 575,015.33
Measurement	Labour Cost for exchanges (maint.)	Meter & Regulator Inst Repl-Company	1	$ 300,769.36
Measurement	Labour Cost for exchanges (maint.)	Meter & Regulator Inst Repl-Company	1	$ 403,553.38
Measurement	Labour Cost for exchanges (maint.)	Meter & Regulator Inst Repl-Contractor	1	$ 445,350.42
Measurement	Labour Cost for exchanges (maint.)	Meter & Regulator Inst Repl-Contractor	1	$ 1,067,220.00
Measurement	Labour Cost for exchanges (maint.)	Meter & Regulator Inst Repl-Contractor	1	$ 421,153.89
Measurement	Labour Cost for exchanges (maint.)	Meter & Regulator Inst Repl-Contractor	1	$ 780,488.34
Measurement	Labour Cost for exchanges (maint.)	Meter & Regulator Inst Repl-Contractor	1	$ 851,475.93
Measurement	Labour Cost for exchanges (maint.)	Meter & Regulator Inst Repl-Contractor	1	$ 712,235.21
Measurement	Regulators/Reliefs	SMC-Meter & Regulator Replacements North	1	$ 5,266,549.22
Measurement	Regulators/Reliefs	SMC-Meter & Regulator Replacements South	1	$ 13,057,454.18
Overheads	General Mains	3rd Party Pre-Work	1	$ 304,621.70
Overheads	General Mains	3rd Party Pre-Work	1	$ 275,000.00
Overheads	General Mains	3rd Party Pre-Work	1	$ 238,846.00
Overheads	General Mains	3rd Party Pre-Work	1	$ 450,000.00
Overheads	General Mains	3rd Party Pre-Work	1	$ 50,000.00
Overheads	General Mains	3rd Party Pre-Work	1	$ 61,200.00
Overheads	General Mains	3rd Party Pre-Work	1	$ 50,000.00
Overheads	0	2018 Contractor Fixed Overhead-STIP	1	$ 1,274,374.00
Overheads	Overheads	O&M Capitalized for OEB	1	$ 44,714,537.00
Overheads	0	Maintenance Cashflow Adj	1	-$ 95,525.00
Pipelines	Valves	King-Distribution Isolation Valves (vari	1	$ 125,147.59
Pipelines	Municipal Replacement	Plan-(B)-Dist-Repl-Contr-Mains Municipal	1	$ 2,087,869.89
Pipelines	Municipal Replacement	Plan-(B)-Dist-Repl-Contr-Mains Municipal	1	$ 4,964,597.57
Pipelines	Municipal Replacement	Plan-(B)-Dist-Repl-Compy-Mains Municipal	1	$ 119,626.20

Asset Category	Portfolio	Description	Priority	2018
Pipelines	Municipal Replacement	Plan-(B)-Dist-Repl-Compy-Mains Municipal	1	$ 103,357.02
Pipelines	Atikokan	NW_Lateral Clamp Cut Outs_ATIKOKAN	1	$ 1,001,200.18
Pipelines	Municipal Replacement	Plan-(B)-Dist-Repl-Contr-Mains Municipal	1	$ 3,085,994.99
Pipelines	General Mains	Indirect Materials-Replacements	1	$ 112,012.00
Pipelines	Anodes	ANODES	1	$ 565,363.29
Pipelines	Municipal Replacement	Plan-(B)-Dist-Repl-Contr-Mains Municipal	1	$ 213,352.80
Pipelines	General Mains	Indirect Materials-Replacements	1	$ 20,223.43
Pipelines	Municipal Replacement	SARN: Vidal St Walking Bridge Municipal	1	$ 798,431.38
Pipelines	Municipal Replacement	Plan-(B)-Dist-Repl-Contr-Mains Municipal	1	$ 2,175,727.93
Pipelines	Anodes	ANODES	1	$ 539,998.00
Pipelines	Anodes	ANODES	1	$ 845,001.84
Pipelines	Municipal Replacement	Plan-(B)-Dist-Repl-Contr-Mains Municipal	1	$ 4,000,000.15
Pipelines	Land Rights-Replacements	Land Rights-Replacements	1	$ 15,000.00
Pipelines	Anodes	ANODES	1	$ 1,219,266.97
Pipelines	Municipal Replacement	Plan-(B)-Dist-Repl-Contr-Mains Municipal	1	$ 2,000,000.40
Pipelines	Land Rights-Replacements	Land Rights-Replacements	1	$ 15,000.00
Pipelines	Municipal Replacement	Plan-(B)-Dist-Repl-Compy-Mains Municipal	1	$ 624,775.44
Pipelines	General Mains	Indirect Materials-Replacements	1	$ 55,235.00
Pipelines	Anodes	ANODES	1	$ 520,399.22
Pipelines	Cased pipe (steel)	King- Casing Upgrade District various -	1	$ 101,079.14
Pipelines	Land Rights-Replacements	Land Rights-Replacements	1	$ 10,000.00
Pipelines	General Mains	Indirect Materials-Replacements	1	$ 33,361.94
Pipelines	Anodes	ANODES	1	$ 718,048.57
Pipelines	Cathodic Protection Advancements	Northwest 2018 Sectionalization	1	$ 381,988.47
Pipelines	Municipal Replacement	NW_7th Ave Bridge_KENORA	1	$ 237,451.44
Pipelines	Municipal Replacement	Plan-(B)-Dist-Repl-Contr-Mains Municipal	1	$ 176,611.07
Pipelines	Land Rights-Replacements	Land Rights-Replacements	1	$ 12,500.00
Pipelines	General Mains	Misc Materials-Company	1	$ 5,523.50
Pipelines	Anodes	Anodes	1	$ 300,729.87
Pipelines	Cathodic Protection Advancements	Sudbury/SSMarie Sectionalization	1	$ 96,588.04
Pipelines	Land Rights-Replacements	Land Rights-Replacements	1	$ 10,000.00
Pipelines	General Mains	Indirect Materials-Replacements	1	$ 36,455.10
Pipelines	Municipal Replacement	Plan-(B)-Dist-Repl-Contr-Mains Municipal	1	$ 176,611.07
Pipelines	Land Rights-Replacements	Land Rights-Replacements	1	$ 12,500.00
Pipelines	General Mains	Misc Materials-Company	1	$ 5,523.50
Pipelines	Anodes	Anodes	1	$ 453,565.35
Pipelines	Cathodic Protection Advancements	North Bay/Orillia Sectionalization	1	$ 382,766.48
Pipelines	Class Location	Class Location Change Progam	1	$ 22,879,027.73
Pipelines	Integrity Management Program	ENG - Integrity Management Program	1	$ 14,061,502.12
Pipelines	Bruce Lake/Ear Falls	Bruce Lake MOP Upgrade	3	$ 5,000,000.00
Pipelines	STO - HPC S&T	STO - HPC S&T	1	$ 250,000.00
Pipelines	Sudbury Line Section 2&3	Sudbury Lateral Repl	2	$ 67,154,375.31
Pipelines	Windsor Line	Windsor Line Ph 1	2	$ 550,000.00
Pipelines	Leakage	Plan-(B)-Dist-Repl-Compy-Mains Leakage	2	$ 35,347.17
Pipelines	Service Replacement	Plan-(B)-Dist-Repl-Compy-Services	2	$ 86,855.94

Asset Category	Portfolio	Description	Priority	2018
Pipelines	Leakage	Plan-(B)-Dist-Repl-Compy-Mains Leakage	2	$ 35,347.17
Pipelines	Service Replacement	Plan-(B)-Dist-Repl-Compy-Services	2	$ 63,049.51
Pipelines	Tools	Capital Tools- Additions-Dist Ops	2	$ 55,892.00
Pipelines	Tools	Capital Tools- Repl- Dist Ops	2	$ 42,245.00
Pipelines	Tools	Capital Tools-Additions-Dist Ops	2	$ 33,440.00
Pipelines	Tools	Capital Tools-Repl-Dist Ops	2	$ 14,806.00
Pipelines	Tools	Capital Tools- Additions-Dist Ops	2	$ 150,000.00
Pipelines	Tools	Capital Tools- Repl- Dist Ops	2	$ 50,000.00
Pipelines	Leakage	Plan-(B)-Dist-Repl-Contr-Mains Leakage	2	$ 329,404.01
Pipelines	Service Replacement	Plan-(B)-Dist-Repl-Contr-Services	2	$ 272,255.48
Pipelines	General Mains	Plan-(B)-Dist-Repl-General Mains	2	$ 238,780.75
Pipelines	Service Replacement	Plan-(B)-Dist-Repl-Compy-Services	2	$ 318,981.91
Pipelines	Leakage	Plan-(B)-Dist-Repl-Contr-Mains Leakage	2	$ 69,512.29
Pipelines	Service Replacement	Plan-(B)-Dist-Repl-Contr-Services	2	$ 65,211.04
Pipelines	General Mains	Plan-(B)-Dist-Repl-General Mains	2	$ 36,177.24
Pipelines	Service Replacement	Plan-(B)-Dist-Repl-Compy-Services	2	$ 15,384.99
Pipelines	Service Replacement	Plan-(B)-Dist-Repl-Contr-Services	2	$ 65,748.18
Pipelines	Service Replacement	Plan-(B)-Dist-Repl-Compy-Services	2	$ 88,716.52
Pipelines	Leakage	Plan-(B)-Dist-Repl-Contr-Mains Leakage	2	$ 299,411.81
Pipelines	Service Replacement	Plan-(B)-Dist-Repl-Contr-Services	2	$ 65,748.18
Pipelines	General Mains	Plan-(B)-Dist-Repl-Contr-Other-Scattered	2	$ 87,722.09
Pipelines	General Mains	Plan-(B)-Dist-Repl-General Mains	2	$ 125,896.25
Pipelines	Service Replacement	Plan-(B)-Dist-Repl-Compy-Services	2	$ 215,492.34
Pipelines	Tools	Capital Tools-Additions-Dist Ops	2	$ 79,000.00
Pipelines	Tools	Capital Tools-Repl-Dist Ops	2	$ 106,000.00
Pipelines	Leakage	Plan-(B)-Dist-Repl-Contr-Mains Leakage	2	$ 200,095.04
Pipelines	Service Replacement	Plan-(B)-Dist-Repl-Contr-Services	2	$ 117,484.53
Pipelines	Service Replacement	Plan-(B)-Dist-Repl-Contr-Services	2	$ 352,453.08
Pipelines	General Mains	Plan-(B)-Dist-Repl-Contr-Other-Scattered	2	$ 199,004.38
Pipelines	General Mains	Plan-(B)-Dist-Repl-General Mains	2	$ 200,031.61
Pipelines	Tools	Capital Tools-Additions-Dist Ops	2	$ 50,000.00
Pipelines	Tools	Capital Tools-Repl-Dist Ops	2	$ 100,000.00
Pipelines	Leakage	Plan-(B)-Dist-Repl-Contr-Mains Leakage	2	$ 542,069.39
Pipelines	Service Replacement	Plan-(B)-Dist-Repl-Contr-Services	2	$ 274,475.57
Pipelines	General Mains	Plan-(B)-Dist-Repl-General Mains	2	$ 268,091.36
Pipelines	Service Replacement	Plan-(B)-Dist-Repl-Compy-Services	2	$ 241,898.86
Pipelines	Tools	Capital Tools-Additions-Dist Ops	2	$ 25,000.00
Pipelines	Tools	Capital Tools-Repl-Dist Ops	2	$ 118,700.00
Pipelines	Leakage	Plan-(B)-Dist-Repl-Contr-Mains Leakage	2	$ 185,886.50
Pipelines	Service Replacement	Plan-(B)-Dist-Repl-Contr-Services	2	$ 451,149.38
Pipelines	General Mains	Plan-(B)-Dist-Repl-General Mains	2	$ 403,225.10
Pipelines	Service Replacement	Plan-(B)-Dist-Repl-Compy-Services	2	$ 250,889.98
Pipelines	Service Replacement	Plan-(B)-Dist-Repl-Compy-Services	2	$ 228,577.76
Pipelines	Tools	Capital Tools Add-Eastern Dist	2	$ 120,000.00
Pipelines	Tools	Capital Tools-Repl-Eastern District	2	$ 50,000.00

Asset Category	Portfolio	Description	Priority	2018
Pipelines	Tools	Capital Tools-Adds-Dist Ops	2	$ 99,451.00
Pipelines	Tools	Capital Tools-Repl-Dist Ops	2	$ 99,451.00
Pipelines	Leakage	Plan-(B)-Dist-Repl-Contr-Mains Leakage	2	$ 134,448.11
Pipelines	Service Replacement	Plan-(B)-Dist-Repl-Contr-Services	2	$ 47,747.29
Pipelines	General Mains	Plan-(B)-Dist-Gen Mains	2	$ 182,558.45
Pipelines	Service Replacement	Plan-(B)-Dist-Repl-Comp-Services	2	$ 138,635.00
Pipelines	Tools	Capital Tools-Adds-Dist Ops	2	$ 42,500.00
Pipelines	Tools	Capital Tools-Repl-Dist Ops	2	$ 50,000.00
Pipelines	Leakage	Plan-(B)-Dist-Repl-Contr-Mains Leakage	2	$ 134,448.11
Pipelines	Service Replacement	Plan-(B)-Dist-Repl-Contr-Services	2	$ 47,747.29
Pipelines	General Mains	Plan-(B)-Dist-Gen Mains	2	$ 182,558.44
Pipelines	Service Replacement	Plan-(B)-Dist-Repl-Comp-Services	2	$ 138,635.00
Pipelines	Tools	Capital Tools-Adds-Dist Ops	2	$ 42,500.00
Pipelines	Tools	Capital Tools-Repl-Dist Ops	2	$ 50,000.00
Pipelines	Tools	STO CAPITAL TOOLS REPL - S&T	2	$ 22,094.00
Pipelines	Tools	STO CAPITAL TOOLS ADDITIONS - S&T	2	$ 22,094.00
Pipelines	Tools	Tech Training - Tools Addition	2	$ 25,000.00
Pipelines	Tools	Tech Training - Tools Replacement	2	$ 25,000.00
Pipelines	Tools	Tools Corrosion Engineering	2	$ 50,000.00
Pipelines	Bare and Unprotected steel	WIND-County Rd 31 & 42 Repl-Lakeshore	2	$ 1,524,213.39
Pipelines	Bare and Unprotected steel	SARN:Christina&Lakeshore Leakeage-Sarnia	2	$ 998,041.58
Pipelines	Bare and Unprotected steel	SARN: Spartan West Ph 2- Sarnia	2	$ 489,038.58
Pipelines	Bare and Unprotected steel	LOND: Mt Brydges B Leakage	2	$ 698,628.49
Pipelines	Bare and Unprotected steel	LOND: Jacqueline St Leakage-London	2	$ 748,530.47
Pipelines	Bare and Unprotected steel	HAMI-FiddlersGreenRdLeakage-Ancaster	2	$ 701,587.46
Pipelines	Bare and Unprotected steel	HAMI-ThorpeStLeakage-Dundas	2	$ 381,403.68
Pipelines	Bare and Unprotected steel	HAMI-ChurchStLeakage-Dunnville	2	$ 953,545.12
Pipelines	bridge crossings inspection and replacements	King- Crowe River Bridge - HHD Crossing	3	$ 445,382.35
Pipelines	DOC < 30% SMYS	NW_HWY61&Arthur Exposed 10_TBAY	3	$ 230,722.21
Pipelines	Valves	Northwest Valve Installations	3	$ 146,296.00
Pipelines	Schedule 10 pipe	NW_Sched 10 Replacement_EMO/RAINY	3	$ 5,659,018.84
Pipelines	MOP Verification	MOP Verification remediation	3	$ 509,588.00
Pipelines	Bare and Unprotected steel	BRAN-Temperance St W Leakage Replacement	2	$ 828,684.86
Pipelines	Bare and Unprotected steel	BRAN-Albert Lane Leakage Replacemt BU-V	2	$ 609,085.87
Pipelines	Bare and Unprotected steel	WAT-Lowther St S Repl (King to Queen)	2	$ 95,000.00
Pipelines	NPS 36 Valve Operator Replacement, St Mary Crossover	NPS36 Valve Oper Repl,St Marys Crossover	3	$ 99,521.00
Pipelines	Cathodic Protection Advancements	Sudbury/SSMarie Rectifiers	1	$ 148,033.00
Pipelines	Cathodic Protection Advancements	North Bay/Orillia Rectifiers	1	$ 154,131.00
Service Facilities	50 Keil Drive, New Power House	CS - Head Office Renovations	1	$ 2,093,744.51
Service Facilities	General Capital Maintenance Projects	South Facility unplanned Blanket	1	$ 250,000.00
Service Facilities	General Capital Maintenance Projects	South Furniture, Decor & Flooring	1	$ 135,000.00
Service Facilities	Corporate Security	South Security Additions	1	$ 2,350,000.00
Service Facilities	General Capital Maintenance Projects	South Equipment, Mechanical, Electrical	1	$ 180,000.00
Service Facilities	General Capital Maintenance Projects	South LED Lighting Replacement	1	$ 400,000.00
Service Facilities	General Capital Maintenance Projects	South Grounds & Parking	1	$ 300,000.00

Asset Category	Portfolio	Description	Priority	2018
Service Facilities	General Capital Maintenance Projects	South Roof, Bldg Envelope, Windows/Doors	1	$ 650,000.00
Service Facilities	555 Riverview Addition/Renovation	555 Riverview Engineering	1	$ 1,009,360.00
Service Facilities	General Capital Maintenance Projects	South Facility Assessments	1	$ 50,000.00
Service Facilities	General Capital Maintenance Projects	North Facility Unplanned Blanket	1	$ 250,000.00
Service Facilities	General Capital Maintenance Projects	North Furniture, Decor & Flooring	1	$ 135,000.00
Service Facilities	General Capital Maintenance Projects	North Equipment, Mechanical, Electrical	1	$ 50,000.00
Service Facilities	General Capital Maintenance Projects	North LED Lighting Replacement	1	$ 200,000.00
Service Facilities	General Capital Maintenance Projects	North Grounds & Parking	1	$ 100,000.00
Service Facilities	General Capital Maintenance Projects	North Roof, Bldg Envelope, Windows/Doors	1	$ 150,000.00
Service Facilities	Belleville - New Building	Belleville Facility Construction	1	$ 6,083,889.00
Service Facilities	General Capital Maintenance Projects	North Facility Assessments	1	$ 50,000.00
Stations	Stations Capital Maintenance	Plan(T)-Dist-Stn Measuring/Corrosion Stn	1	$ 138,014.28
Stations	Stations Capital Maintenance	Plan(T)-Dist-Stn Measuring/Corrosion Stn	1	$ 138,014.28
Stations	Atmospheric Tank replacement	Atmospheric Tank replacement	1	$ 320,000.00
Stations	Distribution Operations Station Painting	Station Painting	1	$ 1,500,000.00
Stations	Hamilton Gate 1 & 2	HAMI-HamiltonGate2Stn17X-402-Flamborough	2	$ 3,500,000.00
Stations	Stations Capital Maintenance	Plan(T)-Dist-Stn Measuring/Corrosion Stn	2	$ 228,349.95
Stations	Stations Capital Maintenance	Plan(T)-Dist-Stn Measuring/Corrosion Stn	2	$ 66,506.50
Stations	Stations Capital Maintenance	Plan(T)-Dist-Stn Measuring/Corrosion Stn	2	$ 28,980.00
Stations	Stations Capital Maintenance	Plan(T)-Dist-Stn Measuring/Corrosion Stn	2	$ 107,218.38
Stations	Stations Capital Maintenance	Plan(T)-Dist-Stn Measuring/Corrosion Stn	2	$ 53,609.00
Stations	Stations Capital Maintenance	Plan(T)-Dist-Stn Measuring/Corrosion Stn	2	$ 61,599.05
Stations	Stations Capital Maintenance	Plan(T)-Dist-Stn Mea./Cor	2	$ 108,859.20
Stations	Stations Capital Maintenance	Plan(T)-Dist-Stn Mea./Cor	2	$ 108,859.20
Stations	Stations Capital Maintenance	Kirkwall Backup Generator Replacement	3	$ 149,796.90
Stations	Stations with Significant Corrosion	Dawn Concession 8 Station Repairs	3	$ 36,646.31
Stations	Vaulted Stations	WAT-Stone & Gordon Stn 19V-105R, Guelph	3	$ 320,286.81
Stations	Stations Capital Maintenance	King- College St & Sidney St -Belleville	3	$ 200,000.00
Stations	Stations Capital Maintenance	LOND- Confined Space Removal-Woodstock	3	$ 399,216.25
Underground Storage	Well Integrity - Maintenance Capital upgrades	STO STORAGE WELL UPGRADES	1	$ 250,000.00
Underground Storage	Well Optimization program	Well Optimization Program	2	$ 364,245.90
Underground Storage	Wellhead Telemetry/measurement	Well Measurement Upgrade Program	1	$ 201,899.50
Underground Storage	Well Pad Improvement	Well Pad Improvement	*	$ 100,000.00

* There are a number of projects that did not lend themselves well to the prioritizaiton model used at the time and did not have specific priority assigned. Theses projects were managed on a case by case basis.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Building Owners and Managers Association (BOMA)

Reference: Exhibit B1, Tab 2, Schedule 1, p18, Table 8

Question:

a) Why should the Board approve ICM funding of $235M for Union, which exceeds its maximum eligible incremental capital of $143.3M (see Table 7) by approximately $90M, an increase of about 70%.
b) Please prioritize Union requests for ICM funding among Sudbury, Kingsville, and Stratford.

Response

a) As per the Board's ICM/ACM policy the maximum eligible incremental capital is defined as the difference between the forecasted total capital expenditures for a subject year and the materiality threshold for that year. The maximum eligible incremental capital of $143.3 million, found in Table 7, is the 2019 calculation for the Union rate zones. Enbridge Gas is seeking incremental ICM funding for projects that fit within the maximum eligible incremental capital amount for 2019. Accordingly, Enbridge Gas is not exceeding the 2019 maximum eligible incremental capital.

   As noted in the applicant's evidence at Exhibit B1, Tab 2, Schedule 1, page 18, the Sudbury Replacement project is a 2018 project for which Enbridge Gas is requesting ICM funding. Please see Exhibit I.STAFF.24 for further detail on the Sudbury Replacement project ICM request. The total ICM funding of $235.2 million includes the required funding for the Sudbury Replacement project ($91.9 million), and the 2019 ICM projects ($143.3 million).

b) Sudbury Replacement, Kingsville Reinforcement and Stratford Reinforcement projects are all required to ensure the safe and reliable service to customers. These projects were all approved as part of leave to construct applications, where the purpose, need, and timing were all considered by the Board as part of that approval. These projects are prioritized using the methodology as outlined in Exhibit C1, Tab 3, Schedule 1 pages 51 to 58.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Building Owners and Managers Association (BOMA)

Reference: Exhibit B1, Tab 2, Schedule 1, p25; Kingsville

Question:

(a) Please provide a detailed breakdown of the cost increase for the Leave to Construct forecast of $105.7M to the current forecast of $121.4M, an increase of about 15%.
(b) Please show the Union revenue requirement impact of the ICM treatment of the project for each year from 2019 to 2023.

Response

(a) Please see Exhibit I.EP.16.

(b) The forecast Kingsville Reinforcement project's ICM revenue requirement, for each year from 2019 to 2023, is shown at Exhibit B1, Tab 2, Schedule 1, Table 11, page 31. Table 11 has been updated and is filed along with the interrogatory response.

Please see Exhibit I.BOMA.37, part (a) for further breakdown of the revenue requirement.

The total revenue requirement for each year of the deferred rebasing period is provided in Table 11.

Table 11
Total Incremental Revenue Requirement by Rate Zone

Line No.	Particulars ($000's)	2019 (a)	2020 (b)	2021 (c)	2022 (d)	2023 (e)	
	EGD Rate Zone						
1	Don River Replacement	(370)	1,137	1,227	1,218	1,207	
	Union North Rate Zone						
2	Sudbury Replacement	9,762	9,633	9,499	9,358	9,212	
	Union South Rate Zone						
3	Kingsville Reinforcement	(3,358)	10,269	10,598	10,681	10,731	/u
4	Stratford Reinforcement	(766)	2,146	2,221	2,249	2,267	
5	Total Union South Rate Zone	(4,124)	12,415	12,820	12,930	12,998	/u
6	Total Incremental Revenue Requirement	5,267	23,185	23,546	23,507	23,418	/u

The Don River Replacement, Kingsville and Stratford Reinforcement projects have a 2020 in-service capital forecast of approximately $1.1 million, $3.2 million and $0.6 million respectively that have been included in the calculation of the incremental revenue requirement for the deferred rebasing period. Enbridge Gas proposes to reduce the maximum eligible incremental capital in 2020 by the actual in-service amounts in that year related to the 2019 ICM approved projects. The detailed incremental revenue requirement detailed for each of the 2019 ICM projects for the deferred rebasing period is filed as Appendix E.

In the first calendar year of a project's in-service date, the revenue requirement may be a credit balance due to utility timing differences associated with the difference between utility income and

ENBRIDGE GAS INC.
Answer to Interrogatory from
Building Owners and Managers Association (BOMA)

Reference: Exhibit B1, Tab 2, Schedule 1, pp24-25

Question:

Given that the Sudbury project was to replace an existing section of mains pipe with integrity issues, why is this not treated as a normal part of ongoing utility operations?

Response

Please refer to Exhibit B1, Tab 2, Schedule 1, pages 18 to 20 for an explanation on why this project could not be funded through existing rates. For further details please see Exhibit I.STAFF.24.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Building Owners and Managers Association (BOMA)

Reference: Exhibit B1/Tab 2/Schedule 1/Pg.27

Question:

Please explain the required five years of growth, the proposed MOP of the proposed pipeline, if proposed as replacement of the smaller diameter pipeline or new greenfield construction. Please provide a map and commentary on what is being proposed.

Response

The Stratford Reinforcement project is a 10.8 kilometer, NPS 12 pipeline project with a MOP of 6160 kpa. The proposed facilities loop an existing NPS 8 section of the Forest, Hensall, Goderich ("FHG") system. The project will provide an additional 16,400 m^3/hour of capacity to the FHG system. Based on the current customer forecast this capacity will meet eight years of customer demand on the system.

A map of the proposed facilities can be found at Schedule 1 of the leave to construct application EB-2018-0306.

The project was approved by the Board on March 28, 2019. Construction is proposed to start in May 2019.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Building Owners and Managers Association (BOMA)

Reference: Exhibit B1, Tab 2, Schedule 1, p28

Question:

Were any of Kingsville, Sudbury, or Stratford proposals put to customers during the Union consultation conducted by Innovative, as was done for similar projects in the Alectra case? If so, what were the results? If not, why not?

Response

Specific questions on the Kingsville, Sudbury or Stratford proposals were not put to customers during the Union consultation conducted by Innovative.

Please see Exhibit I.STAFF.33 for an overview of how Innovative's results were incorporated into the business plans.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Building Owners and Managers Association (BOMA)

Reference: Exhibit B1, Tab 2, Schedule 1, p31

Question:

Please provide an additional piece to Table 11 which shows the total forecast revenue requirement for each of EGD and Union rate zones for each year of the deferral rebasing year.

Response

Enbridge Gas is seeking the Board's approval of the 2019 revenue requirement, the detail of which can be found at Exhibit B1, Tab 1, Schedule 1, page 2.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Building Owners and Managers Association (BOMA)

Reference: Exhibit B1, Tab 2, Schedule 1, p32

Question:

Why is EGD deferring the payment to customers in 2019, but not deferring the collection of debits in the remaining year of the deferral rebasing period?

Response

Please see Exhibit I.BOMA.7.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Building Owners and Managers Association (BOMA)

Reference: Exhibit B1, Tab 2, Schedule 1, p33

Question:

Please explain more fully the cost allocation for the Don River Replacement Project, including the cost allocation method, for extra high pressure mains greater than four inch diameter. What is the MOP and normal operating pressure of the existing line, and how does the high pressure and diameter reflected in the allocation factor?

Response

The EGD rate zone mains network is sized to meet peak demand capacity on the distribution system. It is divided into three systems based on operating pressure: extra high pressure ("XHP") (also referred to as transmission pressure ("TP")), high pressure ("HP"), and low pressure ("LP").

The Board found in EB-2012-0459 (2014 Rate Case) that Rate 125 customers (which are extra-large unbundled firm distribution service customers, such as large power generators) should not be allocated the costs of extra high pressure mains of less than 6" in diameter. Accordingly, the extra high pressure capacity classification is further split into XHP Capacity for mains less than or equal to 4 inch in diameter (XHP Capacity <=4") and XHP Capacity for mains greater than 4 inches (XHP Capacity>4").

Such a classification of XHP mains capacity ensures that Rate 125 customers are only allocated the costs of mains capacity that is physically capable of serving their loads.

Given that the proposed Don River Replacement project is NPS 30 (i.e., 30 inches in diameter) and will operate at extra high pressure, the Board-approved allocation methodology for the EGD rate zone for such a project is the allocation of extra high pressure mains greater than 4 inches in diameter (XHP Capacity>4").

The allocator for XHP Capacity>4" represents / reflects each customer class contribution to the peak demand on the XHP main network.

The ICM revenue requirement for the Don River Replacement project will accordingly be allocated and recovered across all of the EGD rate zone's distribution customer classes, including Rate 125 customers.

The MOP for the existing NPS 30 line is 480 psi and the normal operating pressure is 367 psi.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Building Owners and Managers Association (BOMA)

Reference: Exhibit C1, Tab 3, Schedule 1

Question:

Please provide a copy of the Organizational Strategic Plan.

Figure 1.9.1 provides a snapshot of a mature pipeline system, in which annual maintenance, including replacements and repairs, and capital are on average at least twice the growth capital. Please confirm that Union has prioritized its capital and maintenance projects for 2019, 2020, and the balance of the deferral rebasing period to 2023, and please provide a prioritized list of all projects, in excess of $5M. Please also file the business case for each of these projects, which are being initiated in 2019, and separately, in 2020, if not already in evidence.

Response

Please see Exhibit I.BOMA.40.

As outlined in section 4.2.1.1.4 on page 55 to 58 in Union rate zone's AMP, filed at Exhibit C1, Tab 3, Schedule 1, all projects within the 10-year outlook are prioritized based on the information available at the time of the plan creation.

All project descriptions/business cases for projects in excess of $2M identified in the 10-year asset plan are provided in Appendix D, page 157 to 278 in Union rate zone's AMP filed at Exhibit C1, Tab 3, Schedule 1.

Please see Exhibit I.BOMA.22 for a complete summary of all projects by year in the Enbridge Gas asset plans.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Consumers Council of Canada (CCC)

Reference: Ex. A/T3/S1/p. 2

Question:

The evidence set out the annual bill impacts associate with the Application. With respect to those impacts:

1) Please explain whether they include the disposition of the DVA balances proposed for 2019. If they do please break out the impacts between the rate adjustment and all other factors;

2) Please explain why, if the bill impact of the ICM for the Union North residential customers is $8.80, why the overall impact is $6.81 and $4.88 for each of the Union North rate zones (North East and North West)

Response

1) Enbridge Gas is not seeking to dispose of 2019 deferral and variance account ('DVA') balances as part of this application. Consistent with legacy EGD and Union's past practice, Enbridge Gas will seek disposition of its 2019 DVA balances after 2019 financial results are finalized. Similarly, Enbridge Gas will seek disposition of 2018 DVA balances in the coming months.

2) The ICM bill impact of $8.80 for Union North Rate 01 residential customers is higher than the overall Rate 01 residential bill impact because in the absence of ICM, residential customers would experience an overall bill decrease. The estimated bill impact excluding ICM for a Rate 01 residential customer would be a decrease of $1.99 and $3.92[1] for Union North West and Union North East, respectively.

[1] Union North East bill impacts excluding ICM provided at Exhibit I.BOMA.1, Attachment 1.

The ICM bill impact of $8.80 is partly offset by:

- a decrease in the allocation of DSM budget costs to Rate 01, and
- an increase in the forecast billing units used to derive the Rate 01 base unit rates resulting from an increase in the NAC target included in rates.

Other 2019 rate adjustments result in a bill increase to Rate 01, such as PCI, the deferred tax drawdown base rate adjustment, and capital pass-through projects adjustment.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Consumers Council of Canada (CCC)

Reference: Ex. A/T3/S1/p. 8

Question:

Please explain what relief EGI is seeking from the OEB with respect to the new Conditions of Service. Does EGI have plans to consolidate the Conditions of Service for all of the rate zones (Union and EGD)? If so, what is the timing associated with this initiative?

Response

Enbridge Gas is not seeking relief from the Board with respect to the new Conditions of Services. The revised Conditions of Service were filed in accordance with the Board's Gas Distribution Access Rule ("GDAR"), section 8.5 "Revisions to a Customer Service Policy". Section 8.5 is provided below for convenience.

8.5 Revisions to a Customer Service Policy

8.5.1	A rate-regulated gas distributor shall provide advance public notice of any revisions to its Customer Service Policy. Notice shall be, at a minimum, provided to each residential customer by means of a note on or included with the customer's bill. The notice shall include the timeline for implementation of the revisions to the Customer Service Policy.
8.5.2	A rate-regulated gas distributor shall provide the Board with a copy of its revised Customer Service Policy. The revised Customer Service Policy shall be accompanied by a cover letter that indicates the revisions made and their implementation date.

Enbridge Gas currently has no plans to consolidate its Conditions of Service. Any integration of Enbridge Gas's Conditions of Service must follow the integration of its systems and processes.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Consumers Council of Canada (CCC)

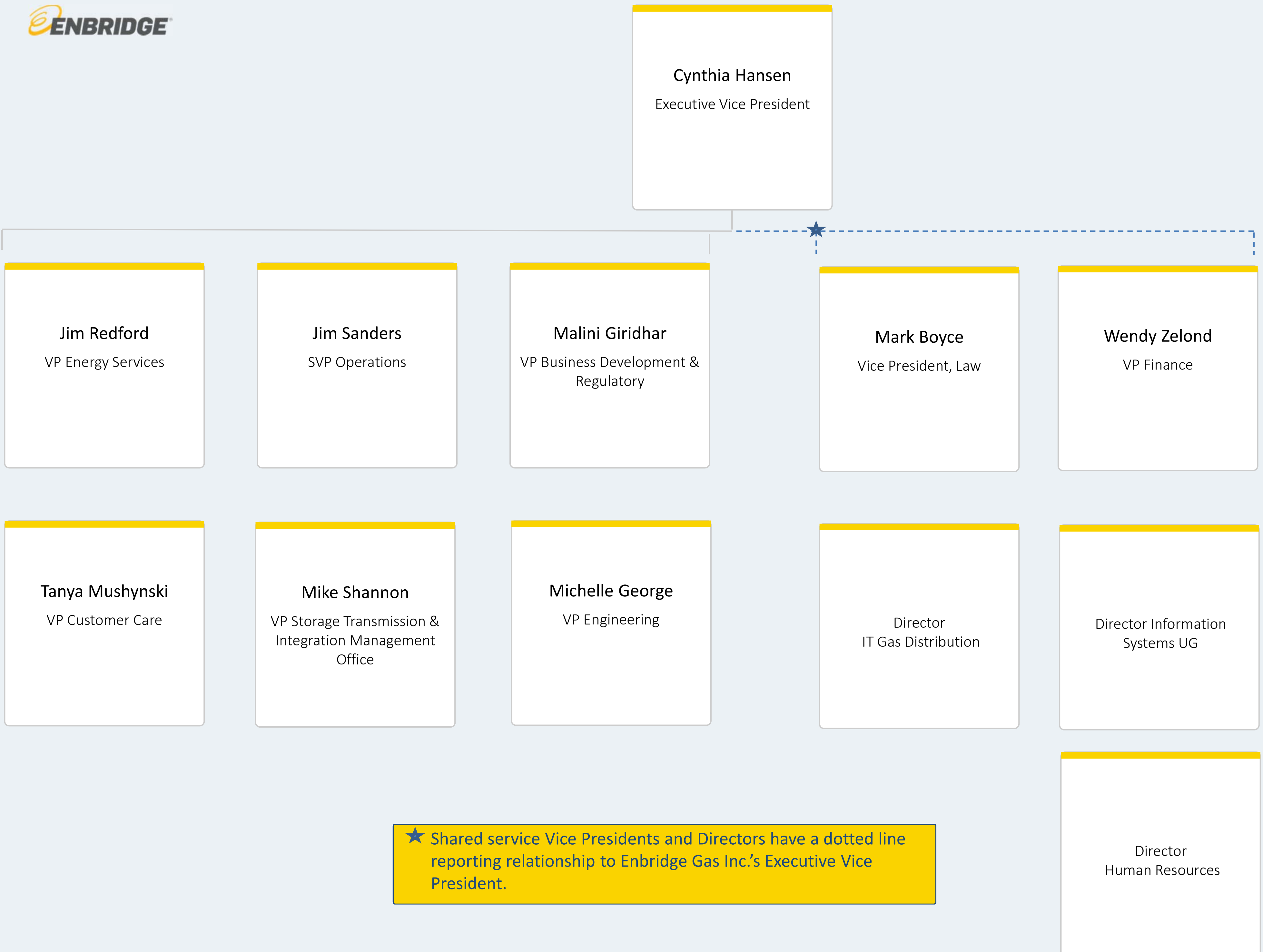
Reference: Ex. A

Question:

Please provide the most recent Company-wide organization chart down to the Director level.

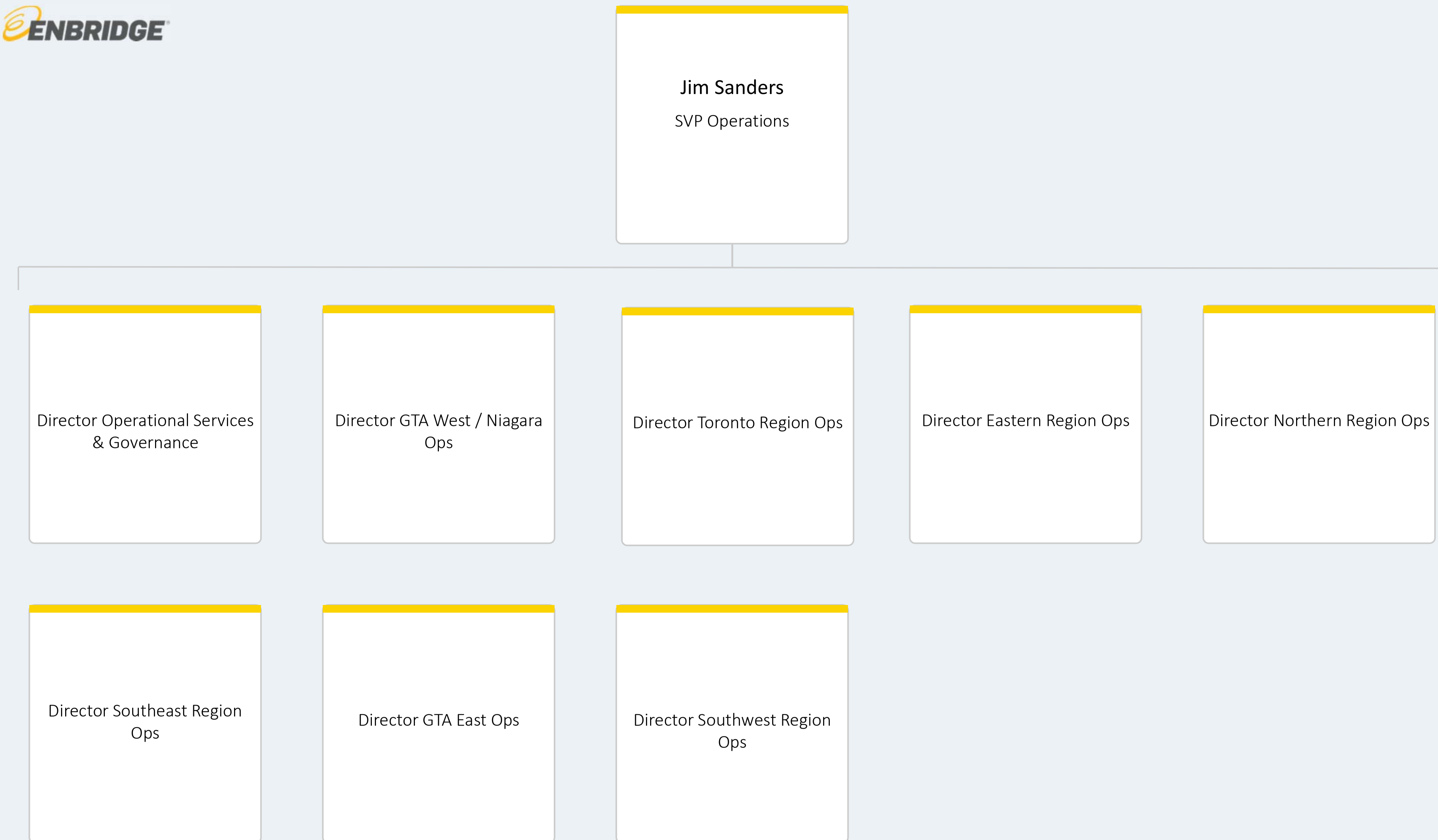
Response

Please see Attachment 1.


ENBRIDGE
Cynthia Hansen
Executive Vice President
Jim Redford
VP Energy Services
Jim Sanders
SVP Operations
Malini Giridhar
VP Business Development & Regulatory
Mark Boyce
Vice President, Law
Wendy Zelond
VP Finance
Tanya Mushynski
VP Customer Care
Mike Shannon
VP Storage Transmission & Integration Management Office
Michelle George
VP Engineering
Director
IT Gas Distribution
Director Information Systems UG
Director
Human Resources
★ Shared service Vice Presidents and Directors have a dotted line reporting relationship to Enbridge Gas Inc.'s Executive Vice President.

- **Jim Redford**
  VP Energy Services
  - Director Gas Supply
  - Director Gas Control & Management
  - Director Energy Services
  - Director S&T Business Development

ENBRIDGE

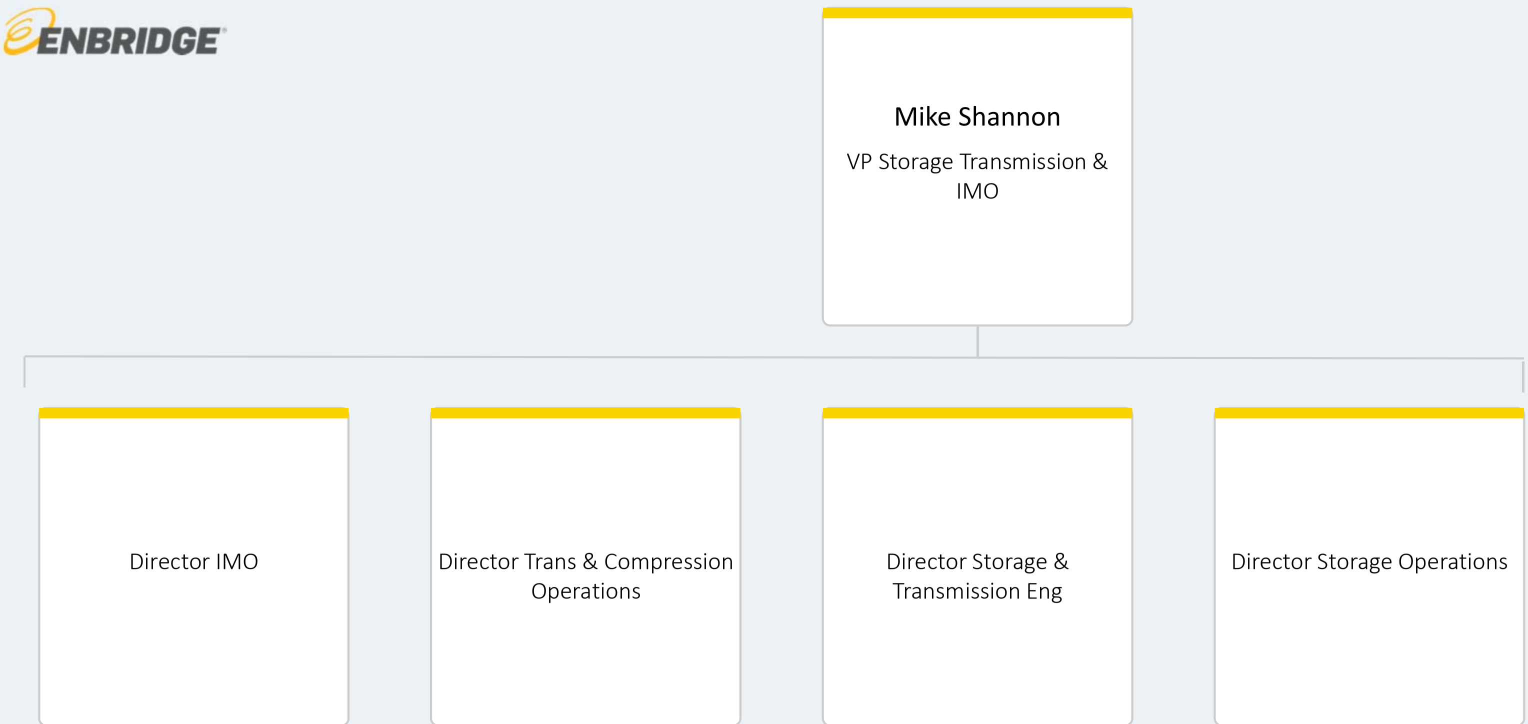

Jim Sanders
SVP Operations
Director Operational Services & Governance
Director GTA West / Niagara Ops
Director Toronto Region Ops
Director Eastern Region Ops
Director Northern Region Ops
Director Southeast Region Ops
Director GTA East Ops
Director Southwest Region Ops

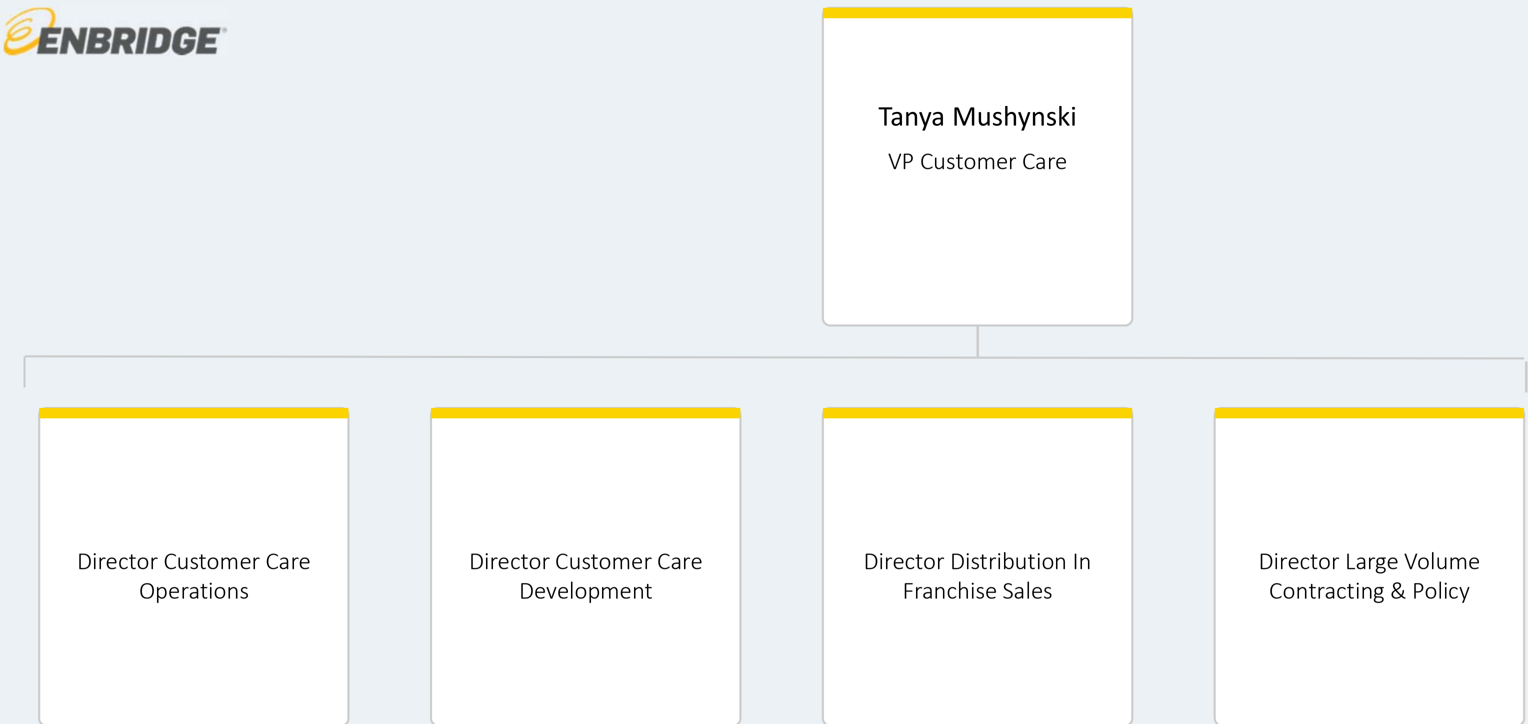
Malini Giridhar
VP Business Development & Regulatory

- Director Public Affairs & Ombudsman
- Director Regulatory Affairs
- Dir Marketing & Energy Conservation
- Director Business Development

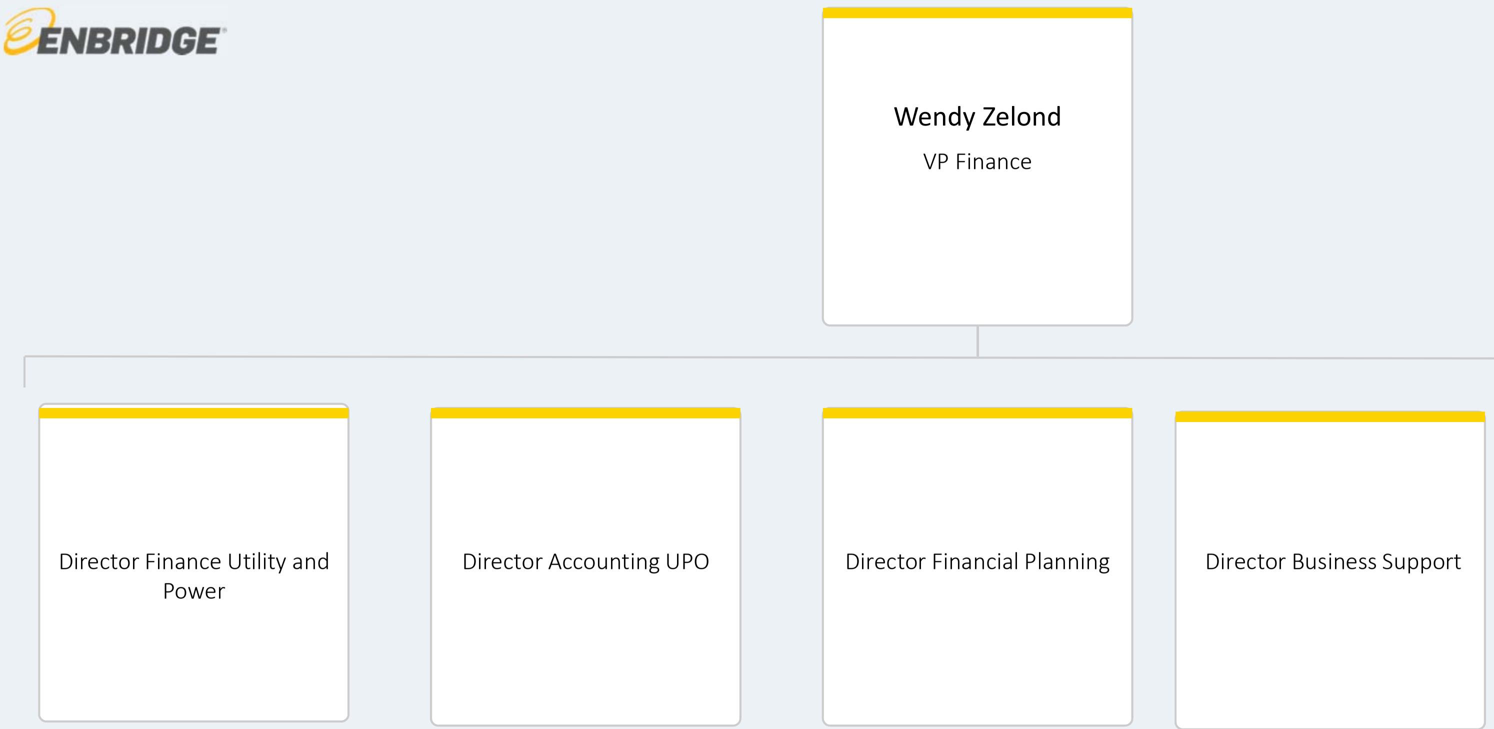
Michelle George
VP Engineering

- Director Asset Management
- Chief Engineer
- Director System Improvement
- Director Integrity & IMS


Mike Shannon
VP Storage Transmission & IMO
Director IMO
Director Trans & Compression Operations
Director Storage & Transmission Eng
Director Storage Operations


Tanya Mushynski
VP Customer Care
Director Customer Care Operations
Director Customer Care Development
Director Distribution In Franchise Sales
Director Large Volume Contracting & Policy

ENBRIDGE


Wendy Zelond
VP Finance
Director Finance Utility and Power
Director Accounting UPO
Director Financial Planning
Director Business Support

Mark Boyce
Vice President, Law

- Associate General Counsel
- Associate General Counsel

ENBRIDGE

ENBRIDGE GAS INC.
Answer to Interrogatory from
Consumers Council of Canada (CCC)

Reference: Ex. B1/T1/S1

Question:

The Application is based on the OEB's Decision approving the amalgamation of Union and EGD and establishing the rate-setting mechanism (EB-2017-0306/0307). Please indicate if the Application is entirely consistent with all of the elements of the Decision. If it is not, please identify where it is not consistent and the rationale for any alternative proposals.

Response

Yes, the application is consistent with the Board's Decision and Order for the amalgamation and rate setting mechanism dated August 30, 2018. The implications of the Board's Decision are reflected in this rate application.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Consumers Council of Canada (CCC)

Reference: Ex. B1/T1/S1/p. 23

Question:

Table 9 provides a list of Deferral Account closures that were approved in the MAADs and Rate-setting Decision. What are the current balances in the accounts?

Response

Please see Attachment 1 for balances in the Deferral Accounts listed at Table 9.

The amounts shown are draft. Disposal of the actual amounts will be filed as part of Enbridge Gas's 2018 Earning Sharing Mechanism and Deferral and Variance Account proceeding.

Account Number	Account Name	Account Balance	Interest*	Total
EGD Rate Zone				
179.16_	Customer Care CIS Rate Smoothing Deferral Account	219,260	(32,375)	$ 186,885
179.34_	Constant Dollar Net Salvage Adjustment Deferral Account	-	-	$ -
179.96_	Relocations Mains Variance Account	-	-	$ -
179.98_	Replacement Mains Variance Account	-	-	$ -
179.58_	Earnings Sharing Mechanism Deferral Account (replaced by new Enbridge Gas account)	(27,350,000)	(167,519)	$ (27,517,519)
Union Rate Zones				
179-120	CGAAP to IFRS Conversion Costs	-	-	$ -
179-134	Tax Variance Deferral Account (replaced by new Enbridge Gas account)	(413,448)	(4,783)	$ (418,231)

*Includes interest to March 31, 2019.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Consumers Council of Canada (CCC)

Reference: Ex. B1/T1/S1/p. 27

Question:

EGI has a forecast of $117.238 million for the Capital Pass-Through Projects for 2019. Will this amount be trued up based on actual costs? If not, why not? If so, how will the amounts be trued up?

Response

Enbridge Gas does not propose to true up the 2019 revenue requirement for Union's capital pass-through projects in 2019 rates to actual costs during the deferred rebasing period with the exception of utility tax timing differences which will continue to be captured in the capital pass-through deferral accounts. Please see Exhibit I.STAFF.8, part (a).

ENBRIDGE GAS INC.

Answer to Interrogatory from
Consumers Council of Canada (CCC)

Reference: Ex. B1/T2/S1/p. 19

Question:

Please set out all project costs for the Sudbury Replacement Project. What is the expected revenue requirement impact for each year 2019-2023? Please explain why it is appropriate for the 2018 costs to be part of the 2019 ICM.

Response

Please see Exhibit I.EP.16 for the project costs for the Sudbury Replacement Project.

Please refer to Exhibit B1, Tab 2, Schedule 1, Appendix E, page 2 for the revenue requirement for each year 2019-2023.

Please see Exhibit I.STAFF.24 part (a) for appropriateness of including 2018 costs as part of 2019 ICM.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Consumers Council of Canada (CCC)

Reference: Ex. B1/T2/S1/p. 24

Question:

With respect to the Sudbury Replacement Project $3.4 million in expected to go into service in 2019. What is the month in which it is expected to be in-service?

Response

Please see Exhibit I.APPrO.2.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Consumers Council of Canada (CCC)

Reference: Ex. B1/T2/S1/p. 22

Question:

With respect to the NPS 30 Don River Replacement Project what were the costs that were presented in the LTC proceeding? What are the current cost projections? Please explain, in detail, all variances. Please provide the construction schedule that was filed in the LTC proceeding and the current construction schedule. What is the most current projected in-service date? What factors could impact that schedule?

Response

Please see Exhibit I.EP.16.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Consumers Council of Canada (CCC)

Reference: Ex. B/T2/S1/p. 27

Question:

With respect to the Kingsville Reinforcement Project what were the costs that were presented at the LTC proceeding. What are the current cost projections? Please explain, in detail, all variances. Please provide the construction schedule that was filed in the LTC proceeding. What is the most current projected in-service date? What factors could impact that schedule?

Response

Please see Exhibit I.EP.16.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Consumers Council of Canada (CCC)

Reference: Ex. B/T2/S1/p. 27

Question:

What is the current status of the LTC Application regarding the Stratford Reinforcement Project? What is the most current projected in-service date? What factors could impact that date?

Response

On March 28, 2019 the Ontario Energy Board approved the Stratford Reinforcement project. Construction of the project is proposed to start in May 2019 with an in service date in November 2019. Based on the past history of constructing projects of this type, Enbridge Gas does not anticipate any factors which would delay the in-service date of the project.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Consumers Council of Canada (CCC)

Reference: Ex. B/T2/S1/p. 31

Question:

EGI has set out the Total Incremental Revenue Requirement by rate zone for each of the ICM requested projects. Does EGI propose a true-up process regarding these projects? If not, why not? If so, how would that true-up process work?

Response

The applicant is requesting the opening of new deferral accounts for each rate zone to capture any variances between actual revenue requirement of the ICM projects and the actual revenue collected through the ICM rate as filed on page 16 of Exhibit B1, Tab 1, Schedule 1. Also, as noted on page 33 in the MAADs Decision (EB-2017-0306 EB-2017-0307) and as per section 7.4 in the Report of the Board (EB-2014-0219), the Board will make a determination on the treatment of any differences between forecast and actual ICM projects at the time of rebasing.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Consumers Council of Canada (CCC)

Reference: Ex. C1/T1/S1/p. 55

Question:

Please file the Customer Connection Policy that was revised in 2015. Please explain the nature of the changes made in 2015 and the rationale for those changes. Please specifically identify how the Contribution in Aid of Construction was changed. Please explain the extent to which EGD undertook any customer engagement with respect to these changes.

Response

Enbridge Gas's feasibility policy has always been aligned with the requirements of E.B.O. 188. In 2015, the EGD rate zone enhanced its process for estimating the service cost used for assessing feasibility of residential conversion customers. The current policy has been filed with this application as Exhibit B1, Tab1, Schedule 1, Appendix H.

Prior to the enhancement in 2015, as noted in Exhibit B1, Tab 1, Schedule 1, Appendix H, paragraph 9, EGD applied a simplified approach to assess economic feasibility which assumed consistent or like circumstances for standard residential service connections.

The underlying assumptions of like circumstances and sufficient cost recovery which allowed EGD to maintain the simplified approach have changed. There is now recognition of increased variability in the cost associated with residential customer attachments which warrants a more precise assessment of individual project costs. The EGD rate zone now accounts for this variability in customer circumstances through assessments by using an individually estimated volumetric allowance and a regionally tailored cost estimate based on historical data from similar services in the same area where available or based on a specific field estimate where necessary. CIAC is now calculated based on customer specific volumetric allowance and cost estimates.

Please see Exhibit I.STAFF.2, part (b) for the customer communication process that was undertaken by the EGD rate zone with respect to this change.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Consumers Council of Canada (CCC)

Reference: Ex. A/T3/S1/ p. 4

Question:

Please indicate what relief EGI is seeking from the OEB with respect to the Utility System Plan and the Asset Management Plans for the EGD and Union rate zones.

Response

Enbridge is not seeking approval of the Utility System Plan and Asset Management Plans ("USP" and "AMPs"). Subsequent to the filing of this IR the Board issued its Decision and Procedural Order No. 2 which confirms this:

"The OEB confirms that it will not be approving the USP or AMPs in this proceeding. The review of the USP and AMPs is to provide context for whether the ICMs should be approved."[1]

[1] Decision and Procedural Order No. 2, April 1, 2019, pages 5 to 6.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Consumers Council of Canada (CCC)

Reference: Ex. B1/T2/S1/p. 5

Question:

Please explain why EGI has excluded Community Expansion amounts from System Access Capital?

Response

Community Expansion is categorized under the System Access Capital investment category in Enbridge Gas's Utility System Plan.[1]

> Despite their opportunities being evaluated using the same investment valuation framework, opportunities outside of core business activities that have different funding mechanisms and are driven and supported through public and governmental policies/regulations do not flow through this process (such as Community Expansion, renewable natural gas, etc.) [emphasis added].[2]

As such, footnotes were included for Table 1 and Table 2 in Enbridge Gas's Incremental Capital Module: "System Access capital presented here does not reflect Community Expansion."[3]

[1] Exhibit C1, Tab1, Schedule 1 page 36.
[2] Exhibit C1, Tab1, Schedule 1, page 29.
[3] Exhibit B1, Tab 2, Schedule 1, Tables 1 and 2, pages 4 to 5.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Consumers Council of Canada (CCC)

Reference: Ex B1/T2/S1/p. 2

Question:

The evidence states that, "As there are finite resources to complete capital projects, projects are selected for the AMP on the basis of their relative priority. All projects are evaluated and prioritized/optimized to ensure that capital resources are employed to address the highest priority items across all asset categories." Please explain if this comment pertains to planning with respect to the two rate zones individually or to the consolidated Company. When does EGI intend to undertake capital planning across the Company as a whole?

Response

The comment pertaining to planning is relevant to the EGD and Union rate zones. Conversely each AMP was created individually with unique prioritization/optimization methodology. The following excerpt highlights the common considerations included in both planning methodologies:

"Enbridge Gas's methodology for project prioritization/optimization considers risk, customer input and preferences, resource availability and asset portfolio strategies."[1]

As per the response at Exhibit I.STAFF.34, Enbridge Gas is still assessing its future asset management processes.

[1]Exhibit, B1, Tab 2, Schedule 1, page 3.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Consumers Council of Canada (CCC)

Reference: Ex. B1/T2/S1/p. 9 and Ex. C1/T1/S1/p. 3

Question:

Does EGI intend to use a Company-wide materiality threshold for its ICM requests for 2021?

Response

Enbridge Gas does not intend to use a Company-wide materiality threshold for its ICM requests for 2021. Please see Exhibit I.VECC.7.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Consumers Council of Canada (CCC)

Reference: Ex. A/T3/S1/p. 5

Question:

Please explain what relief EGI is seeking from the OEB with respect to the customer consultation undertaken by both EGD and Union.

Response

Enbridge Gas is not seeking any specific relief from the Board with respect to the customer engagement filed at Exhibit D1. The Board confirmed this in its Decision and Procedural Order No. 2:

> The OEB agrees with Enbridge Gas that customer engagement is relevant to the USP and AMP planning processes, and therefore is a consideration for the review of the ICMs. It is generally not a requirement to file the results of customer engagement with IRM applications that do not include ICMs, given the mechanistic nature of the Price Cap IR rate adjustments. A new issue on customer engagement has not been added to the Issues List, as proposed by VECC, because the customer engagement will be considered as part of whether the projects are eligible for ICM funding.[1]

[1] Decision and Procedural Order No. 2, April 1, 2019, page 6.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Canadian Manufacturers &Exporters (CME)

Reference: Exhibit B1, Tab 2, Schedule 1, page 9 of 36

Question:

At Exhibit B1, Tab 2, Schedule 1, EGI states: "Enbridge Gas proposes to use a simple average of the actual annual PCI that has been used to increase rates during the price cap IR term since its last rebasing". According, to EGI, this is because "the average PCI more accurately reflects the impact PCI has had on rates and revenue since the bas year than the use of the current year PCI."

(a) What impact would using the current year PCI% of 1.07% have on the Union rate zone's materiality threshold? Please show all calculations to the degree that they are not already part of the evidence.

(b) Assuming the use of current year PCI% has impact an impact on the Union rate zone's materiality threshold, does that impact EGI's capital planning or specific projects? If so how?

Response

a) Please see Exhibit I.LPMA.11 for the impact of using a PCI% of 1.07% to calculate the Union rate zones' materiality threshold.

Using the 2019 PCI of 1.07% for Union instead of using the six year average PCI of 0.72% in the threshold formula would indicate that the rates have been adjusted at 1.07% in each individual year for the period of 2014-2019. The cumulated rate increase would have been 6.42% instead of an actual cumulated rate increase of 4.31% as seen in the table on the following page.

Year	2019 PCI	Actual PCI
2014	1.07%	0.51%
2015	1.07%	0.66%
2016	1.07%	0.71%
2017	1.07%	0.70%
2018	1.07%	0.66%
2019	1.07%	1.07%
Simple cumulative Total	6.42%	4.31%
Arithmetic Average	1.07%	0.72%

As a result, the threshold amount for Union would have been over-estimated by approximately $23.3 million by using the higher PCI rate of 1.07% instead of 0.72%.

b) 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, including the materiality threshold, will have an impact on capital planning. All projects identified within the Asset Management Plans have been identified to fulfill a need and will be completed.

Investments in the EGD rate zone are optimized based on the Asset Management Principles outlined in Section 4.1.3.4 Optimize Portfolio Based on Asset Management Principles (p. 71-4). Please refer to the Asset Management Core Process steps Risk Management (Section 4.2.1 p. 79), Solution Planning (Section 4.2.2 p. 83) and Portfolio Optimization (Section 4.2.3 p. 84).[1]

Some projects have more flexibility than others in the timing of their execution and these are the projects that may either be brought forward or deferred if there was a change to the materiality threshold.

[1] Exhibit C1, Tab 2, Schedule 1; Exhibit C1, Tab 3, Schedule 1, pages 46 to 58.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Canadian Manufacturers &Exporters (CME)

Reference: Exhibit B1, Tab 2, Schedule 1, page 13 of 36; Report of the OEB, EB-2014-0219 – New Policy Options for the Funding of Capital Investments: Supplemental Report

Question:

At Exhibit B1, Tab 2, Schedule 1, page 13, EGI states: "Enbridge Gas recognizes the Board considered and did not change the approach of comparing weather-normalized revenues to weather-actual revenues in the EB-2014-0219 Supplemental Report. The Board's explanation for not changing the approach was due to the high proportion of electric revenues from fixed charges that are non-weather sensitive."

In the Board's supplemental report regarding options for funding capital investments, the Board also stated that another reason for keeping the weather actual demand was that KPMG found no "quantitative evidence that the present calculation is resulting in a systematic bias in the materiality threshold formula, resulting in a misspecification of the amount of capital that is reflected in rates."

(a) Is EGI leading any evidence in this proceeding regarding a possible systematic bias in the materiality threshold formula? If so, please provide references to its location in EGI's application.

(b) If the answer to (a) above is no, why not?

Response

Enbridge Gas is not leading evidence on this topic.

Enbridge Gas recognizes the Board considered and did not change the approach of comparing weather-normalized revenues to weather-actual revenues in the EB-2014-0219 Supplemental Report.

In the Supplemental report, the Board also observes that any error introduced is reduced by the proportion of revenues that are from non-weather-sensitive charges such as the monthly fixed service charge among others (variable charges for non-weather sensitive customer classes, and due to the fact that there is base load consumption even for weather-sensitive customers).

As stated in Exhibit B1, Tab 2, Schedule 1, page 13 of the evidence, Enbridge Gas has a considerably higher proportion of volumetric charges that are weather sensitive for general service customers than electric LDCs. If the weather-actual results are used in the calculation, then the year over year weather fluctuations would cause more volatility in the year-over-year ICM threshold amount. Using a weather-normalized approach levels this volatility and provides a more predictable outcome.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Canadian Manufacturers &Exporters (CME)

Reference: Exhibit B1, Tab 2, Schedule 1, pages 24-25 of 36

Question:

At Exhibit B1, Tab 2, Schedule 1, pages 25-26, EGI discusses the Sudbury Replacement Project.

(a) Please explain all variances between the approved EB-2017-0180 filing budget and the budget provided in EGI's present application.

Response

Please see Exhibit I.EP.16.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Canadian Manufacturers &Exporters (CME)

Reference: Exhibit B1, Tab 2, Schedule 1, pages 25-26 of 36

Question:

At Exhibit B1, Tab 2, Schedule 1, pages 25-26, EGI discusses the Kingsville Reinforcement Project

(a) Please confirm whether the current cost projections are still $121.4 million for the Kingsville Reinforcement project?

(b) To the extent that the cost projections have changed, please provide the current cost projections, and explain all variances.

Response

a-b) Please see Exhibit I.EP.16.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Canadian Manufacturers &Exporters (CME)

Reference: Exhibit D1, Tab 1, Schedule 1, page 2 of 86

Question:

At Exhibit D1, Tab 1, Schedule 1, page 2, EGI has provided a report by Ipsos Public Affairs.

(a) The report is labelled as a “Draft Report”. Was a final report produced by Ipsos? If so, please file it as part of this proceeding. If not, why not?

(b) When were the final reports by Ipsos and Innovative Research Group Inc. delivered to Enbridge and Union respectively?

(c) Please outline how the results of the reports were incorporated in the development of Enbridge and Union’s (or EGI’s) business planning. Are there any specific projects or investments which were scheduled or postponed as the result of the customer consultations, if so, which projects or investments were they?

Response

(a) EGD’s customer engagement study was conducted by Ipsos and a report of the findings was provided to the company in August 2017. The report was final at the time and was titled as draft as it was an expectation that a customer engagement study would be an ongoing endeavor within utility business planning.

(b) Both customer engagement reports were delivered in August 2017.

(c) Please see Exhibit I.STAFF.33.

ENBRIDGE GAS INC.
Answer to Interrogatory from
EPCOR Natural Gas Limited Partnership (ENGLP)

Reference: Exhibit B1, Tab 1, Schedule 1, p. 40 and Appendix H

Preamble: Appendix H is filed in response to a commitment by Enbridge (in its 2017 ESM Proceeding (EB-2018-0131) to file evidence about the refined feasibility analysis approach for residential infill customers (p. 40).

Appendix H: (a) is said to apply to the “EGD Rate Zone”; (b) purports to address “key elements of the Company policy under the Community Expansion framework as approved by the Board in E-2016-0004 ...”; and (c) sets out Enbridge’s procedures and policies to comply with EBO 188.

Further, paragraph 10 on page 3 of 8 of Appendix H states that “Where the use of a proposed facility is dominated by a single large volume customer, it is conserved a dedicated facility for CIAC purposes.”

Question:

(a) Please advise whether this policy applies to the Union Rate Zone as well.

(b) Please advise whether this policy would apply to customers connecting to transmission (as opposed to distribution) assets.

(c) Could paragraph 10 noted in the preamble above apply to a “facility” connecting to a transmission (as opposed to a distribution) asset? Please provide a definition of “dominant customer”.

Response

(a) No. Please see Exhibit I.STAFF.2, part (e).

(b) The enhancements were made to ensure compliance with the distribution system guidelines laid out in EBO 188. Cost estimation for transmission projects has not been affected by this change.

c) As explained in (b) above, this Policy only applies to connecting to distribution customers. Dominant Customer is a term used to describe a situation when a pipe is extended to serve multiple customers and where one of the customers' peak demand consumes more than 75% of the capacity of the line.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Energy Probe Research Foundation (EP)

Reference: Exhibit A1, List of Evidence

Question:

a) Please confirm the Application conforms fully to the OEB's EB-2017-0307 MAADs Decision and Rate Order.

b) If not, please list all items with evidentiary references, that deviate from the Decision and Rate Order.

c) Please provide a summary of the basis of any of the listed deviations.

Response

a-c) Confirmed. Please see Exhibit I.CCC.4.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Energy Probe Research Foundation (EP)

Reference: Exhibit A1

Question:

Please provide the most recent EGI organization chart down to the Director level.

Response

Please see Exhibit I.CCC.3.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Energy Probe Research Foundation (EP)

Reference: Exhibit A1, Tab 5, Schedule 2, Conditions of Service Section 6.4.1: Exhibit A1, Tab 5, Schedule 4.

Preamble:

"Federal Carbon Charge
Pursuant to the Greenhouse Gas Pollution Pricing Act (GGPPA), gas distributors are required to pay to the federal government a fixed carbon charge for use and deliveries of natural gas to customers. This charge is billed based on the amount of natural gas consumed by customers other than industrial emitters who are registered under the GGPPA Output-Based Pricing System (OBPS). For any fixed carbon and OBPS charges that Enbridge must pay to the federal government for its transmission and storage facilities, these charges are included in the "Delivery to You" item on the bill.

Question:

a) Please confirm (with reference) the Decision/Directive to include the Federal Carbon Charge in the "Delivery to You" item of the Customer Bill.

b) Clarify if/how this Directive differs to the presentation of the prior Cap and Trade GHG item.

c) Please provide an estimate of the amounts of the charge (monthly/yearly) for Residential Customers in EGD and Union Rate Zones and compare to the 2017/2018 Cap and Trade charge.

Response

a) On January 11, 2019 Enbridge Gas filled an application with the Board related to the Federal Carbon Pricing Program.[1] Enbridge has requested approval from the Board to add Federal Carbon Charge as a separate line item on customer bills, which will reflect the charge on the customers natural gas use / consumption. Enbridge has also requested approval from the Board to add a Facility Carbon Charge, which will

[1] EB-2018-0187/EB-2018-0205

reflect the charge on company use volumes and costs related to the Output Based Pricing System ("OBPS") for the Company's transmission and storage facilities. Enbridge Gas has proposed that the Facility Carbon Charge would be included in the "Delivery to You" item on the customer bill. At this time, there is no Decision/Directive related to how the federal carbon charge would be shown on the bill. However, the Minister of Energy, Northern Development and Mines encouraged the Board in a letter issued on February 20, 2019 to ensure a transparent process around the implementation of the federal carbon charge on natural gas bills that provided opportunity to consider stakeholder input. Subsequently, on April 3, 2019, the Board issued its procedural order on the federal carbon charge which includes the opportunity for stakeholder comment around the bill presentment matter.

b) See response to a). For clarity, the Board made a decision in Cap and Trade that the customer and facility related costs associated with that program would be included within the "Delivery to You" line item.[2]

c) Please see Attachment 1.

[2] EB-2015-0363 OEB Determination regarding Billing of Cap and Trade Related Costs and Customer Outreach, July 28, 2016, page 5.

ENBRIDGE GAS INC.
Typical Residential Bill Impact of the Proposed Federal Carbon Pricing Program and the 2017/2018 Cap-and-Trade Compliance Plan

Line No.	Particulars ($)	Rate (cents/m^3)	January	February	March	April	May	June	July	August	September	October	November	December	Annual Total
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n) = sum(b:m)
	EGD Rate Zone														
	Rate 1														
1	Consumption Volumes (m^3)		419	404	354	252	158	69	51	54	58	91	174	316	2,400
2	Proposed Federal Carbon Charge (1)	3.9100	16.38	15.80	13.84	9.85	6.18	2.70	1.99	2.11	2.27	3.56	6.80	12.36	93.84
3	Proposed Facility Carbon Charge (1)	0.0036	0.02	0.01	0.01	0.01	0.01	-	-	-	-	-	0.01	0.01	0.08
4	Total	3.9136	16.40	15.81	13.85	9.86	6.19	2.70	1.99	2.11	2.27	3.56	6.81	12.37	93.92
5	Cap-and-Trade Customer-Related Charge (2)	3.3181	13.90	13.41	11.75	8.36	5.24	2.29	1.69	1.79	1.92	3.02	5.77	10.49	79.63
6	Cap-and-Trade Facility-Related Charge (2)	0.0337	0.14	0.14	0.12	0.08	0.05	0.02	0.02	0.02	0.02	0.03	0.06	0.11	0.81
7	Total	3.3518	14.04	13.55	11.87	8.44	5.29	2.31	1.71	1.81	1.94	3.05	5.83	10.60	80.44
	Union Rate Zones														
	Rate 01 and Rate M1														
8	Consumption Volumes (m^3)		385	403	332	200	114	64	48	46	48	106	158	295	2,200
9	Proposed Federal Carbon Charge (3)	3.9100	15.05	15.74	12.99	7.83	4.47	2.49	1.89	1.81	1.89	4.13	6.19	11.53	86.01
10	Proposed Facility Carbon Charge (3)	0.0084	0.03	0.03	0.03	0.02	0.01	0.01	-	-	-	0.01	0.01	0.02	0.17
11	Total	3.9184	15.08	15.77	13.02	7.85	4.48	2.50	1.89	1.81	1.89	4.14	6.20	11.55	86.18
12	Cap-and-Trade Customer-Related Charge (4)	3.3181	12.77	13.36	11.02	6.64	3.80	2.12	1.61	1.53	1.61	3.50	5.26	9.78	73.00
13	Cap-and-Trade Facility-Related Charge (4)	0.0240	0.09	0.10	0.08	0.05	0.03	0.02	0.01	0.01	0.01	0.03	0.04	0.07	0.54
14	Total	3.3421	12.86	13.46	11.10	6.69	3.83	2.14	1.62	1.54	1.62	3.53	5.30	9.85	73.54

Notes:
(1) EB-2018-0187/EB-2018-0205, Exhibit E, Tab 1, Schedule 1, p.3.
(2) EB-2016-0300, Decision and Rate Order, Appendix D, p. 1.
(3) EB-2018-0187/EB-2018-0205, Exhibit E, Tab 2, Schedule 1, p.3.
(4) EB-2016-0296, Rate Order, Appendix A, p. 1, column (c), lines 13 & 14 and p. 7, column (c), lines 6 & 7.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Energy Probe Research Foundation (EP)

Reference: Exhibit B1, Tab 1, Schedule 1, Pages 3 and 5, Tables 2 and 3

Question:

Please provide a copy of the Statistics Canada Table 36-10-0106-01 (formerly Can Sim 380-066) GDPPI quarterly for 2017 and 2018

a) Please provide the calculations resulting in the values in Table 3.

b) Please provide the equivalent calculations for 2018.

c) Please provide a version of Table 2 using the 2018 Inflation Factor.

Response

The GDP IPI FDD quarterly index for the years 2017 and 2018 obtained from the Statistics Canada Table 36-10-0106-01 are summarized in tables below for both parts a) and b) of the answer:

a) Annual % Change in GDP IPI FDD for 2017:

Year	Quarter	Index	Year Over Year Change	Annual %	Average % Change
2016	Q1	116.5			
2016	Q2	116.4			
2016	Q3	116.9			
2016	Q4	117.5			
2017	Q1	118.0	1.5	1.29%	
2017	Q2	118.5	2.1	1.80%	
2017	Q3	118.2	1.3	1.11%	
2017	Q4	119.0	1.5	1.28%	1.37%

b) Annual % Change in GDP IPI FDD for year 2018

Year	Quarter	Index	Year Over Year Change	Annual %	Average % Change
2017	Q1	108.0			
2017	Q2	108.5			
2017	Q3	108.3			
2017	Q4	109.0			
2018	Q1	109.4	1.4	1.30%	
2018	Q2	109.9	1.4	1.29%	
2018	Q3	110.6	2.3	2.12%	
2018	Q4	111.1	2.1	1.93%	1.66%

c) The calculated Price Cap Index using the 2018 Inflation factor is shown below:

	Price Cap Index
Inflation factor	1.66%
Less: Productivity Factor	0.00%
Less: Stretch Factor	0.30%
Price Cap Index	1.36%

ENBRIDGE GAS INC.
Answer to Interrogatory from
Energy Probe Research Foundation (EP)

Reference: Exhibit B1, Tab 1, Schedule 1, Page 12- AUTVA (Enbridge) and NAC (Union);

Question:

EGD Rate Zones
Exhibit F1, Tab 1, Rate Order, Working Papers, Schedule 10

a) Please show Graphically, for Rate 1 and Rate 6, the average use for the last 10 years and for the forecast period. Please provide a comment on the accuracy of the model and trends.

b) Please provide a status report on the review of Average Use models for EGD as agreed in the EB-2017-102, Settlement at Exhibit N1, Tab 1, Schedule 1, page 8

Union Rate Zones
Exhibit F1, Tab 2, Rate Order, Working Papers, Schedule 13.

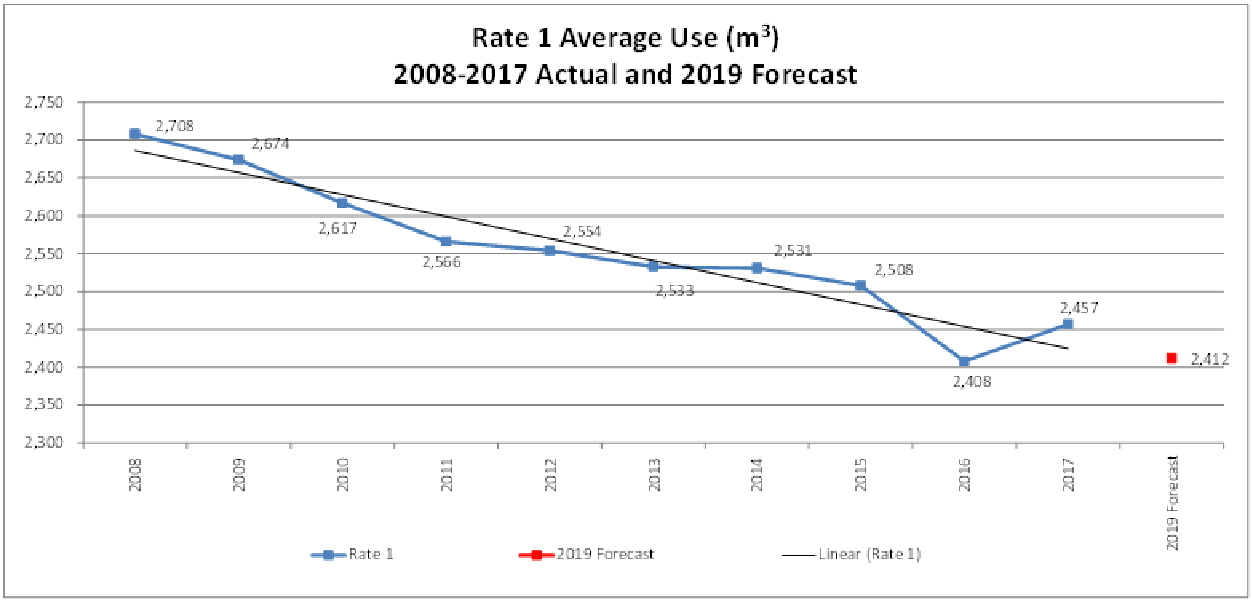
c) Please show Graphically for Rate M1 and M2, the average use for the last 10 years and for the forecast period. Please provide a Comment on the accuracy of the model and trends.

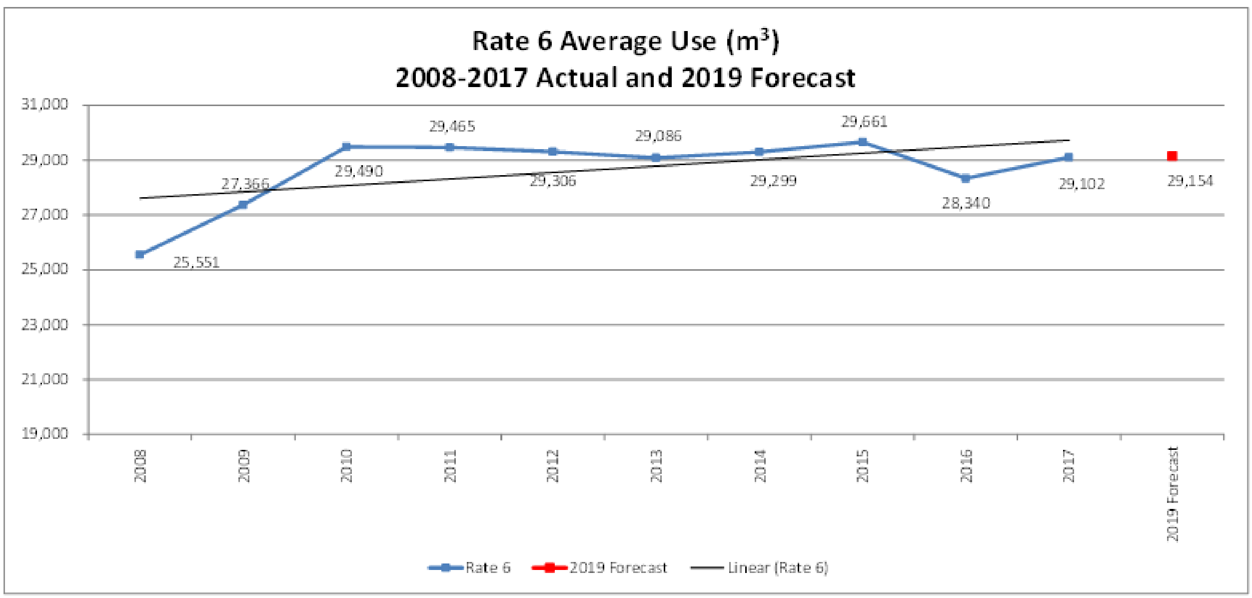
d) Please provide a status report on the review of Average Use models for Union as in the EB-2016-0118 Settlement paragraph 12.

Response

a) The Rate 1 and 6 average uses that are normalized to 2019 Board approved degree days are shown in the charts below.

   The 2019 forecast is developed using the data up to 2017. During the last 10 years Rate 1 average use declined 9.3% from 2,708 m3 in 2008 to 2,457 m3 in 2017. Rate 6 in the same period increased 13.9% from 25,551 m3 in 2008 to 29,102 m3 in 2017. For accuracy results, please see Exhibit I.STAFF.5, part a) Table 1, which provides the 10-Year history of Normalized Actual vs. Board-Approved average uses. Out-of-sample average percentage variance over the last 10 years is -0.5% for Rate 1 and 0.5% for Rate 6. The results support the view that the General Service average use forecasting methodology continues to be a reliable predictor for General Service average use.





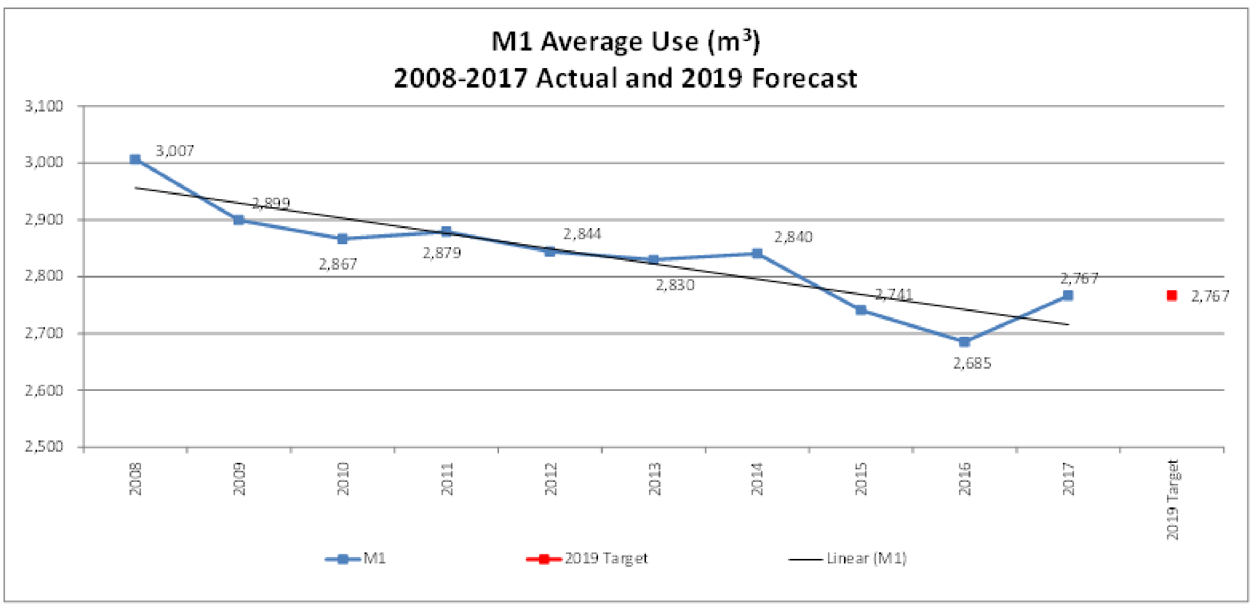
b) As per the Board's Decision and Order in the MAADs and Rate Setting Mechanism proceeding, Enbridge Gas will develop a proposal for the average use methodology for its next rebasing application.[1]

c) The weather normalized average use at the 2019 Board approved normal, for Rate M1 and Rate M2 are shown in the charts below.

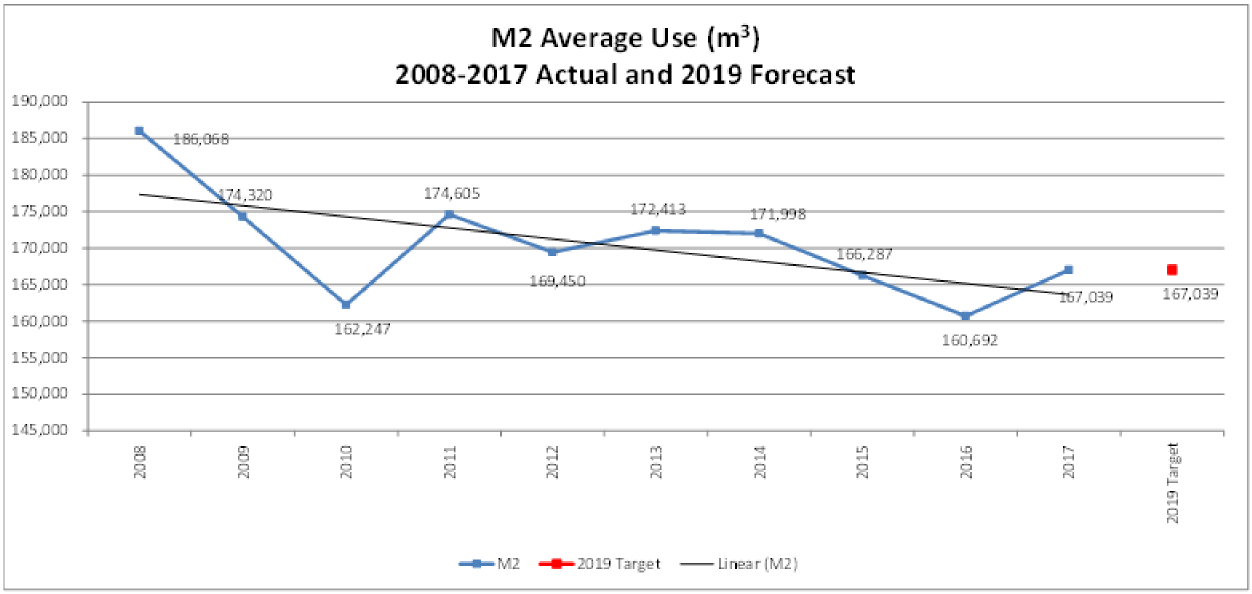
Over the last 10 years, Rate M1 NAC declined 8.0% from 3,007 m3 in 2008 to 2,767 m3 in 2017. Rate M2 NAC for the same period decreased 10.2% from 186,068 m3 in 2008 to 167,039 m3 in 2017.

When adjusting rates each year for changes to NAC, Union applies the most recent actual NAC for each rate class, calculated using the Board-approved 50:50 weather normal for the forecast year. For 2019 rates, 2017 actual NAC calculated using the 2019 weather normal is used for each rate class.

Because of actual customer behavior in each rate class, there has been some variability from year to year in the actual NAC, with an overall declining trend. Enbridge Gas is currently evaluating methodologies regarding NAC forecasting, and will file a proposal with its next rebasing application.



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



d) Please see the response to part b).

ENBRIDGE GAS INC.
Answer to Interrogatory from
Energy Probe Research Foundation (EP)

Reference: Exhibit B1, Tab 1, Schedule 1, Page 14, Table 4, Appendices A&B

Question:

a) Please provide a redline comparison of the existing EGDI and Union ESM DAs and new EGDI ESMDA.

b) Please explain in detail the changes to the dead band threshold and sharing for each Rate Zone.

c) Please provide examples of the ESM calculations for 2019 using 0 -300 bps excess earnings

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Response

a) Enbridge Gas's ESMDA is a new deferral account, distinct from the earnings sharing mechanism deferral accounts used prior to 2019 for each of the legacy utilities. It is not an update of the existing EGD and UGL ESMDAs, therefore a redline comparison has not been attached.

   Please see Exhibit I.STAFF.19 for a revised Enbridge Gas ESMDA accounting order.

b) Commencing in 2019, Enbridge Gas will calculate earnings sharing based on the utility results for the amalgamated company. In accordance with the MAADs decision, earnings sharing will be calculated on actual utility results (not normalized), and earnings in excess of 150 basis points above the Board approved ROE will be shared 50/50 between ratepayers and the Company.

   Under EGD's 2014 – 2018 Custom IR plan, if the actual utility ROE, calculated on a weather normalized basis, was greater than the Board approved ROE, the excess earnings were shared 50/50 between ratepayers and EGD.

   Under Union's 2014 – 2018 Price Cap plan, if the difference between the actual (not normalized) utility ROE and the Board approved ROE was greater than 100 basis points, but less than 200 basis points, the excess earnings were shared 50/50 between ratepayers and Union. If the difference between the actual utility ROE and the Board approved ROE exceeded 200 basis points, the excess over 200 basis points was shared 90/10 between ratepayers and Union.

c) The requested information is not relevant to the relief being sought. Enbridge Gas does not have a combined ESM calculation model at this time.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Energy Probe Research Foundation (EP)

Reference: Exhibit B1, Tab 1, Schedule 1, Page 26; Exhibit F1, Tab 2, Rate Order, Working Papers, Schedule 16, pp. 4-5.

Preamble: "*Enbridge Gas proposes a one-time adjustment of ($10.4) million associated with the capital pass through projects ("Projects") that were included in rates as a Y factor during Union's 2014-2018 IRM term. The proposed adjustment represents the difference between the 2018 Project revenue requirement of $127.6 million included in Union's Board-approved 2018 rates and the 2019 forecast Project revenue requirement of $117.2 million.*"

Question:

a) Please confirm that the costs of the projects and adjustments are subject to prudence review.

b) When will this review occur?

Response

a) Not confirmed, the one-time adjustment is not subject to a prudence review.

b) Any prudence review of the final capital pass through capital expenditures should take place at rebasing.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Energy Probe Research Foundation (EP)

Reference: Exhibit B1, Tab 1, Schedule 1, Page 29

Preamble: "*Enbridge Gas has added 30,393 GJ/d of project demands to the allocation of the 2019 project costs and to the derivation of the 2019 Rate M12/C1 Dawn-Parkway demand rate as part of this application. As the revenue of the surplus capacity will be built into 2019 rates, there is no longer a requirement to track the revenue associated with the surplus capacity in the project deferral account.*"

Question:

a) Please provide a schedule with the term(s) and prices realized for the surplus capacity (names other than EGI affiliates omitted).

b) Please provide a Comparison of the annual revenue and average unit costs to the M12/C1 rates.

c) Please provide references for data/calculations.

Response

a) Please see Exhibit I.STAFF.11, part (a).

b) Please see Exhibit I.STAFF.11, part (f).

c) Please see Exhibit I.STAFF.11, part (f).

ENBRIDGE GAS INC.
Answer to Interrogatory from
Energy Probe Research Foundation (EP)

Reference: Exhibit B1, Tab 1, Schedule 1, Page 30, Table 11 and Appendix E

Preamble: *"Enbridge Gas proposes to adjust the customer-related cost variance for the Union rate zones in proportion to the current approved revenue, assuming the monthly customer charge revenue is recovered in the first delivery block of the volumetric delivery charges."*

Question:

a) Please provide clarity on the pathway and endpoint for M1 and M2 customer charges over the 5-year period.

b) Please explain how is it appropriate in the context of rate design principles, that by adjusting the first delivery rate block to include the monthly customer charge revenue, the bill impacts are more consistent for each customer within the rate class regardless of annual volumes consumed.

c) Are there similar rate design/customer charge changes contemplated for EGDI Rate zones?

Response

a) Enbridge Gas is not proposing any changes to the level of monthly customer charges for Rate M1 and Rate M2 in 2019.

b) By adjusting the first delivery block to include the monthly charge revenue, such revenue is then recovered from all customers, as all customers consume volumes within the first delivery block. This proposal is similar / analogous to the recovery of the monthly customer charge, which is paid by all customers regardless of volumes consumed. The proposal also addresses the significant bill impacts for certain Rate M1 and Rate 01 customers, which is also a rate design consideration.

c) There are no proposed changes to the EGD rate zone monthly customer charges for general service customers in 2019.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Energy Probe Research Foundation (EP)

Reference: Exhibit B1, Tab 1, Schedule 1, Page 33 and pages 41-46 Appendix l; Exhibit F1, Tab 2, Rate Order, Working Papers, Schedule 11.

Preamble: *“The MAADs Decision requires Enbridge Gas to track actual costs and amounts recovered through rates related to the PDO during the deferred rebasing period for review at the time of rebasing.*
Enbridge Gas proposes to update the allocation of the PDO and PDCI demand-related costs based on the 2019 Dawn-Parkway design day demands and the allocation of the in-franchise compressor fuel costs based on 2019 forecast volumes.”

Question:

a) Please provide a schedule that summarizes the total allocation of 2019 PDO and PDCI costs and bill impacts for each of the four EGI rate zones, as provided in the evidence at pages 43/44. Provide explanatory notes.

b) When/how will EGI/Union report on the PDCI volumes and balances?

c) If there are differences between the forecast in rates and actuals, how will these be addressed?

d) Given the utility restructuring and that:*“As of November 1, 2017 the initial Parkway shortfall has been fully eliminated as a result of Dawn to Kirkwall turnback, and therefore Union did not need to take action to manage the shortfall”.*
Why should the PDO continue for the next 5 years? Please discuss.

Response

a) Please see Table 1.

Table 1
UNION RATE ZONES
PDO and PDCI Costs and Residential Bill Impacts

Line No.	Particulars	PDO and PDCI Costs Allocation (1) ($000's)	Residential Customer Bill Impact (2) ($)
		(a)	(b)
1	Union North West	1	0.00
2	Union North East	9	0.03
3	Union South	23,861	8.67
4	Union Ex-franchise – EGD	214	0.06
5	Union Ex-franchise – Other	638	
6	Total	24,723	

Notes:
(1) The allocation of PDO and PDCI related costs is provided at Exhibit F1, Tab 2, Working Papers, Schedule 11, p. 1.
(2) Based on a typical residential customer annual consumption of 2,200 m^3 in the Union rate zones and 2,400 m^3 in the EGD rate zone.

b) Enbridge Gas does not report on PDCI volumes and balances.

c -d) The Board determined in the MAADs and Rate-Setting Mechanism Decision and Order that PDO will be reviewed at the time of rebasing.[1]

[1] EB-2017-0306 EB-2017-0307 Decision and Order, September 17, 2018, page 48 and 49.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Energy Probe Research Foundation (EP)

Reference: Exhibit B1, Tab 1, Schedule 1, Page 40 and Appendix H

Preamble: *"The MAADs Decision requires Enbridge Gas to track actual costs and amounts recovered through rates related to the PDO during the deferred rebasing period for review at the time of rebasing.*
Enbridge Gas proposes to update the allocation of the PDO and PDCI demand-related costs based on the 2019 Dawn-Parkway design day demands and the allocation of the in-franchise compressor fuel costs based on 2019 forecast volumes."

Question:

a) Is the Feasibility Study filed for Board Approval or information?

b) What changes are there to the Connection Policy Guidelines? Please list any major amendments.

c) Are the Policy/Guidelines applicable to all EGI rate zones?

d) What conclusions should existing ratepayers reach from the feasibility analysis regarding cost consequences of infill projects and Community Expansion projects? Please discuss.

Response

a) Enbridge Gas filed the referenced exhibit for information to the Board in compliance with its commitment made in the 2017 ESM Proceeding, EB-2018-0131. In this proceeding, Enbridge Gas committed to file evidence about the refined feasibility analysis approach for residential infill customers.

b) The change to the Connection Policy Guidelines can be found in Exhibit B1, Tab 1, Schedule 1, Appendix H, page 2, paragraph 9.

c) Please see Exhibit I.STAFF.2, part e).

d) The new approach for determining the economic feasibility of infill services is intended to improve the accuracy of project feasibility calculations. Accurate project feasibility ensures that under contributing projects pay an appropriate amount of contribution (“CIAC”) without causing undue burden on existing ratepayers, an objective of the Board’s E.B.O.188 guidelines for determining the economic feasibility of gas distribution system expansion.

Since the Company’s approach to the determination of the economic feasibility requires system expansion projects to achieve a Profitability Index value of 1.0 or greater there is little, if any, opportunity for existing ratepayers to subsidize the expansion of the Company’s gas distribution system with respect to the addition of new customers. The same holds true for community expansion projects, except that such projects may receive financial assistance from the exiting ratepayers as provided for in Bill 32, the Access to Natural Gas Act, 2018 and its accompanying regulation (Ontario Regulation 24/19).

ENBRIDGE GAS INC.
Answer to Interrogatory from
Energy Probe Research Foundation (EP)

Reference: Exhibit B1, Tab 2, Schedule 1, Page 9 and Table 4

Preamble: "*The Board's ICM materiality threshold calculation results in a 2019 threshold value of $468.513 million for the EGD rate zone and $375.2 million for the combined Union rate zones. The materiality threshold establishes the minimum capital expenditures a utility must fund through base rates. The maximum incremental capital investment eligible for ICM funding is the amount of capital expenditures in the year in excess of the threshold value.*"

Question:

a) Please confirm that per Table 4 the ICM calculation assumes a rate increase for the PCI for 2019 for EGD of 1.07% and Union of 0.72%.

b) Why is EGI proposing a PCI arithmetic average based in the 5-year deferred rebasing period, as opposed to a forecast of expenditures and base rates over the period? Please explain and discuss the options considered.

c) Please explain why a combined consolidated EGI ICM threshold is not more appropriate.

Response

a) The 2019 ICM threshold calculation assumes that, for the EGD rate zone, rates will increase by 1.07% from its 2018 Board Approved rates. For the Union rate zones, the ICM threshold calculation reflects that rates have been increasing at an average of 0.72% since its 2013 Board Approved rates.
Please see Exhibit I.LPMA.12 for the calculation of the average PCI for the Union rate zones.

b) Please refer to:
   - Exhibit B1, Tab 2, Schedule 1, Page 10 and Page 11
   - Report of the OEB EB-2014-0219 "New Policy Options for the Funding of Capital Investments: Supplemental Report" January 22, 2016, page 16

- Decision Order: EB-2017-0306/EB-2017-0307, pages 32, 33

The amalgamation and rate setting mechanism approved by the Board for EGD and Union includes the use of the ICM mechanism for the funding of incremental capital.

The ICM materiality threshold formula estimates the threshold value for multiple years ahead of the base year. The multi-year formula requires that both the growth factor “g” and the PCI factor, be annualized. The proposed annualized PCI is calculated as the arithmetic average since the base year.

c) Please see Exhibit I.VECC.7.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Energy Probe Research Foundation (EP)

Reference: Exhibit B1, Tab 2, Schedule 1, Pages 12 and 13

Preamble: *"To determine the 2017 revenue from general service rate classes, Enbridge Gas used the actual customer count and held the normalized average consumption/average use ("NAC/AU") per customer constant with the NAC/AU in base rates. If the NAC/AU is not held constant, then any change in NAC/AU would have to be offset by a proportionally similar rate adjustment to keep the revenue per customer constant. Both the EGD and Union rate zones have deferral accounts that record the revenue impact associated with the difference between the forecast normalized average use per customer embedded in rates and the actual normalized average use experienced during the year."*

Question:

a) Please confirm that the approved methodology for average use adjustments to rates includes 3-year averaging.

b) Please explain why average use per customer should be held constant for ICM growth, rather than using a rolling 3-year average.

c) Please provide a revised calculation of the growth factor using an average 3-year rolling average of average use. Compare to Table 5 using the constant/holding average use approach.

Response

a) No, the approved methodology for average use adjustments does not include 3 year averaging for either the EGD or Union Rate Zones. The average use adjustment to rates reflects:

- For the EGD rate zone: Rate 1 and Rate 6 customers, the change from the latest Board-approved average use (2018 Budget) to the 2019 average use forecast was used. The 2019 forecast was determined using the Board approved methodology.

- For the Union rate zones: Rate M1, Rate M2, Rate 01 and Rate 10, the change from the latest Board approved NAC (2018 Target) to the 2019 Target NAC was used. The 2019 target NAC is based on the latest available actual use (from two years ago) that is normalized to the 2019 weather normal. This methodology was approved during the EB-2013-0202 (Union's 2014 to 2018 IRM Settlement Agreement) and as subsequently modified in EB-2014-0271 (Union's 2015 Rates proceeding).

b) The value of the growth factor ("g") is the % difference in distribution revenues between the most current year and the base year. The revenues are calculated maintaining the base rate constant.

   Deferral and Variance Accounts are already in place for NAC and AU for the EGD rate zone and Union rate zones and they respectively to true-up any variances from forecast or target. Enbridge Gas is not proposing that those true-up mechanisms change. Therefore, the growth calculation is net of any AU and NAC changes and the difference in revenue year over year would represent the growth in customers only.

c) As noted in part (b) above, the growth factor is calculated net of average use. Any changes in NAC or AU would be trued up through the deferral and variance accounts and would not impact the growth factor.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Energy Probe Research Foundation (EP)

Reference: Exhibit B1, Tab 2, Schedule 1, Page 18, Table 8, and Exhibit. B1, Tab 2, Schedule 1, Page 24, Table 8

Preamble: The Schedules show the Total Incremental ICM by rate zone for each of the ICM funded requested projects.

Question:

Does EGI propose to update the data and will there be a process for discovery regarding material changes in cost and timing.

Response

Please see Exhibit I.CCC.12.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Energy Probe Research Foundation (EP)

Reference: Exhibit B1, Tab 2, Schedule 1, Page 31, Table 11

Question:

a) Please confirm that over the 5 years the net ICM annual revenue requirement (costs and revenue) will vary, based on several factors including timing and the dates of in-service additions (ISAs).

b) Does EGI agree that an ISA RR deferral account for ICM projects, is appropriate to protect ratepayers. If not, please explain why not and/or provide alternatives to an ICM RRVA

Response

a) The Company confirms that the annual revenue requirement for each ICM project could vary from forecast for a number of reasons, which could include variances in the project's costs capitalized into service, and variances in the project's in-service timing.

b) Enbridge Gas has requested an Incremental Capital Module (ICM) Deferral Account for each of the EGD and Union rate zones as per Board policy. As indicated at Exhibit B1, Tab 1, Schedule 1, Page 16, and in each of the draft accounting orders found at Exhibit B1, Tab 1, Schedule 1, Appendix A, page 33, and Appendix B, page 34, the purpose of each of the accounts is to capture any variances between the actual revenue requirement of approved ICM projects and the actual ICM revenues collected through ICM rates. Given the scope of the proposed ICM deferral accounts, to compare actual ICM project revenue requirements against actual ICM revenues, the impact of any variances in-service addition amounts or timing (from forecast), each of which impact the actual project revenue requirement, will be one of the impacts captured within the ICM deferral accounts.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Energy Probe Research Foundation (EP)

Reference: Exhibit B1, Tab 2, Schedule 1, Pages 19 to 27

Question:

a) For each of the proposed ICM projects, please provide the detailed itemized cost estimate including contingency with line by line explanations of differences from the costs approved by the OEB in the LTC proceeding. For each project please provide the current Profitability Index ("PI") and compare it to the PI approved by the OEB in the LTC proceeding. Also please indicate if there have been any changes in the route or schedule of any project from the route and schedule approved by the OEB in the LTC proceeding.

b) For each proposed ICM project where there is a significant difference between the cost, PI and route approved by the OEB in the LTC proceeding and the current cost, PI, and route please explain the meaning of the approvals in the LTC proceeding. For example, should not project cost above what was approved in the LTC proceeding be subject to a prudence review?

c) Please recalculate each ICM proposal using project cost approved by the OEB in the LTC proceeding.

Response

a) Don River Replacement

The table below shows the estimated costs provided in the LTC application and the current cost projections.

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

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. Interest during construction was not included in the costs presented in the LTC application. These costs have been included in the "Cost as Filed in EB-2018-0108" column and Contingency Costs have been reduced by an equivalent amount to maintain the overall cost presented in the LTC application.

The table below shows the estimated schedule provided in the LTC application and the current schedule.

Description	Schedule As Filed in EB-2018-0108	Updated Schedule
Expected LTC Approval	December 2018	November 2018
Reciept of Permits and Approvals	December 2018	April 2019
Commence Construction	January 2019	May 2019
Completion of Construction	September 2019	November 2019
Completion of Reinstatement	October 2019	December 2019
Final Inspection	December 2020	January 2021

The current projected in-service date has changed from October 2019 to December 2019 due to delays in receipt of permits and easements which have caused a delay in construction commencement.

The routing of the proposed facilities has not changed from the route identified in the LTC application.

A DCF analysis was not completed for the Don River Replacement project and therefore no PI calculation is available for this project.

Sudbury Replacement

The table below shows the estimated costs provided in the LTC application and the current cost projections.

Item No.	Description	Cost As Filed in EB-2018-0180	Updated Cost Estimate	Variance
		a	b	b-a
1.0	Materials	$5,379,000	$5,379,000	$0
2.0	Construction & Labour	$58,361,000	$67,261,000	$8,900,000
3.0	Contingencies	$9,561,000	$9,561,000	$0
4.0	Interest During Construction	$756,000	$756,000	$0
5.0	Overheads		$12,300,000	$12,300,000
6.0	Total Project Cost	$74,057,000	$95,257,000	$21,200,000

Variances in estimated costs relative to what was filed in the LTC application can be attributed to the inclusion of indirect overhead costs and an increase in contractor costs due to design changes, inclement weather and construction execution.

The table below shows the estimated schedule provided in the LTC application and the current schedule.

Description	Schedule As Filed in EB-2018-0180	Updated Schedule
OEB Filing	May 2017	May 2017
OEB Decision	September 2017	September 2017
Construction Start	May 2018	April 2018
In Service	November 2018	October 2018

There were no significant changes to the project schedule for the Sudbury Replacement project.

The routing of the proposed facilities did not change from the route identified in the LTC application.

A DCF analysis was not completed for the Sudbury Replacement project and therefore no PI calculation is available for this project.

Kingsville Reinforcement

The table below shows the estimated costs provided in the LTC application and the current cost projections.

Item No.	Description	Cost As Filed in EB-2018-0013	Updated Cost Estimate	Variance
		a	b	b-a
1.0	Materials	$7,725,000	$7,725,000	$0
2.0	Construction & Labour	$82,931,000	$82,931,000	$0
3.0	Contingencies	$13,598,000	$13,598,000	$0
4.0	Interest During Construction	$1,462,000	$1,462,000	$0
5.0	Overheads		$15,700,000	$15,700,000
6.0	Total Project Cost	$105,716,000	$121,416,000	$15,700,000

Variances in estimated costs relative to what was filed in the LTC application can be attributed to the inclusion of indirect overhead costs.

The table below shows the estimated schedule provided in the LTC application and the current schedule.

Description	Schedule As Filed in EB-2018-0013	Updated Schedule
OEB Filing	January 2018	January 2018
OEB Decision	September 2018	September 2018
Clearing	March 2019	March 2019
Construction Start	May 2019	May 2019
In Service	November 2019	November 2019

There have been no changes to the project schedule/in-service date since the original LTC application was filed.

The routing of the proposed facilities has not changed from the route identified in the LTC application.

A revised DCF analysis (per EBO 134) has not been completed. The pre-filed evidence for the Kingsville Reinforcement project showed that the project had a positive NPV of between $341 million and $697 million. The increase in costs due to the inclusion of overheads would not have a significant impact on the NPV of the project.

Stratford Reinforcement

The table below shows the estimated costs provided in the LTC application and the current cost projections.

Item No.	Description	Cost As Filed in EB-2018-0306	Updated Cost Estimate	Variance
		a	b	b-a
1.0	Materials	$2,997,000	$2,997,000	$0
2.0	Construction & Labour	$21,620,000	$21,620,000	$0
3.0	Contingencies	$3,623,000	$3,623,000	$0
4.0	Interest During Construction	$300,000	$300,000	$0
5.0	Total Project Cost	$28,540,000	$28,540,000	$0

There have been no changes to estimated project costs since the LTC was filed. Indirect overhead costs were included in the costs filed in the LTC application.

The table below shows the estimated schedule provided in the LTC application and the current schedule.

Description	Schedule As Filed in EB-2018-0306	Updated Schedule
OEB Filing	November 2018	November 2018
OEB Decision	April 2019	March 2019
Construction Start	May 2019	May 2019
In Service	November 2019	November 2019

There have been no changes to the project schedule/in-service date since the LTC was filed.

The routing of the proposed facilities has not changed from the route identified in the LTC application.

Since there are no changes in estimated project costs the DCF analysis (per EBO 134) for the Stratford Reinforcement project has not been updated since the filing of the LTC application.

b) Enbridge Gas interprets the approval associated with LTC applications, Board findings in the MAADs Decision, and the Board's ICM Policy as allowing for a prudence review of leave to construct projects and other projects for which ICM treatment is sought at the time of rebasing limited to the difference between forecasted and actual spend.

For example, the Board's ICM Policy states under section 7.4*:*

> At the time of the next cost of service or Custom IR application, a distributor will need to file calculations showing the actual ACM/ICM amounts to be incorporated into the test year rate base. At that time, the Board will make a determination on the treatment of any difference between forecasted and actual capital spending under the ACM/ICM, if applicable, and the amounts recovered through ACM/ICM rate riders and what should have been recovered in the historical period during the

> preceding Price Cap IR plan term. Where there is a material difference between what was collected based on the approved ACM/ICM rate riders and what should have been recovered as the revenue requirement for the approved ACM/ICM project(s), based on actual amounts, the Board may direct that over- or under-collection be refunded or recovered from the distributor's ratepayers.[1]

c) The table below shows the forecast annual revenue requirement for each of the proposed ICM projects: assuming the capital costs approved for each project in their respective LTC proceedings, and assuming the cost reduction (generally due to the exclusion of indirect overhead and/or IDC) results in a corresponding reduction in the maximum eligible incremental capital of the applicable rate zone (i.e., reduces the ICM amount).

Enbridge Gas notes however, that while these calculations can be made for illustrative purposes, the reclassification/reassignment of certain costs from these projects does not change the total forecast in-service capital for 2019. As such, to the extent that costs apportioned to these projects are reduced, reducing the project specific ICM eligible amount, it may in turn create capacity for another ICM eligible project.

Total Incremental Revenue Requirement by Rate Zone
Using Project Cost Approved by the OEB in LTC

Line No.	Particulars ($000's)	2019	2020	2021	2022	2023
	EGD Rate Zone					
1	Don River Replacement	(26)	335	386	383	380
	Union North Rate Zone					
2	Sudbury Replacement	7,690	7,720	7,617	7,509	7,396
	Union South Rate Zone					
3	Kingsville Reinforcement	(693)	8,859	9,097	9,187	9,245
4	Stratford Reinforcement	(766)	2,146	2,221	2,249	2,267
5	Total Union South Rate Zone	(1,459)	11,005	11,318	11,436	11,512
6	Total Incremental Revenue Requirement	6,205	19,060	19,321	19,328	19,288

[1] Ontario Energy Board, EB-2014-0219, Report of the Board, New Policy Options for the Funding of Capital Investments: The Advanced Capital Module, page 26.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Energy Probe Research Foundation (EP)

Reference: Exhibit B1, Tab 2, Schedule 1, Page 32

Question:

Based on the response to EP-16 regarding updated ICM project costs and timing, please update the 2019 ICM Net Revenue Requirement in Table 11 and the Allocation to Rate classes for 2019.

Response

Please see Exhibit I.EP.16, part c) for the incremental revenue requirement by rate zone as updated to reflect the leave to construct project costs approved by the Board. Attachment 1 provides the allocation of 2019 project costs reflected in Exhibit I.EP.16, part c).

EGD RATE ZONE
Allocation of 2019 ICM Project Revenue Requirement
Updated for Exhibit I.EP.17

Line No.	Particulars	Delivery Demand TP > 4" Allocator (1) %	Don River Replacement Project (2) (000's)
		(a)	(b)
	EGD		
1	Rate 1	46%	-
2	Rate 6	41%	-
3	Rate 9	0%	-
4	Rate 100	0%	-
5	Rate 110	2%	-
6	Rate 115	1%	-
7	Rate 125	8%	-
8	Rate 135	0%	-
9	Rate 145	0%	-
10	Rate 170	0%	-
11	Rate 200	1%	-
12	Rate 300	0%	-
13	Total	100%	-

Notes:

(1) EGD extra high pressure mains greater than 4 inch diameter are allocated according to the Board approved cost allocation methodology (EB-2017-0086), Delivery Demand TP > 4 inch allocator, reflecting 2019 forecast peak demand by rate class.

(2) 2019 ICM revenue requirement credit balance associated with the Don River Replacement project in the EGD rate zone will be recovered in 2020.

UNION RATE ZONES
Allocation of 2019 ICM Project Revenue Requirement
Updated for Exhibit I.EP.17

		Union North		Union South			
Line No.	Particulars	Distribution Demand Allocator (1) (%)	Sudbury Replacement Project (2) ($000's)	Other Transmission Allocator (3) ($10^3m^3/d$)	Kingsville Reinforcement Project (4) ($000's)	Stratford Reinforcement Project (4) ($000's)	Total ICM Allocation ($000's)
		(a)	(b)	(c)	(d)	(e)	(f) = (b+d+e)
1	Rate 01	40	3,078	-	-	-	3,078
2	Rate 10	13	1,006	-	-	-	1,006
3	Rate 20	27	2,052	-	-	-	2,052
4	Rate 25	2	185	-	-	-	185
5	Rate 100	18	1,369	-	-	-	1,369
6	Total Union North	100	7,690	-	-	-	7,690
7	Rate M1	-	-	31,974	-	-	-
8	Rate M2	-	-	10,986	-	-	-
9	Rate M4 (F)	-	-	5,860	-	-	-
10	Rate M4 (I)	-	-	-	-	-	-
11	Rate M5 (F)	-	-	87	-	-	-
12	Rate M5 (I)	-	-	-	-	-	-
13	Rate M7 (F)	-	-	2,496	-	-	-
14	Rate M7 (I)	-	-	-	-	-	-
15	Rate M9	-	-	546	-	-	-
16	Rate M10	-	-	4	-	-	-
17	Rate T1 (F)	-	-	2,572	-	-	-
18	Rate T1 (I)	-	-	-	-	-	-
19	Rate T2 (F)	-	-	23,429	-	-	-
20	Rate T2 (I)	-	-	-	-	-	-
21	Rate T3	-	-	2,501	-	-	-
22	Total Union South	-	-	80,456	-	-	-
23	Excess Utility Storage	-	-	-	-	-	-
24	Rate C1 (F)	-	-	-	-	-	-
25	Rate C1 (I)	-	-	-	-	-	-
26	Rate M12	-	-	-	-	-	-
27	Rate M13	-	-	-	-	-	-
28	Rate M16	-	-	-	-	-	-
29	Total Ex-Franchise	-	-	-	-	-	-
30	Total Union	100	7,690	80,456	-	-	7,690

Notes:
(1) Union North distribution demand allocation for joint-use mains in proportion to 2019 forecast peak day and average day demands.
(2) Allocated in proportion to column (a).
(3) Union South other transmission demand allocation in proportion to forecast 2019 Union South in-franchise design day demands.
(4) The 2019 revenue requirement credit for the Kingsville and Stratford Reinforcement projects will be netted with the 2020 revenue requirement in the allocation to rate classes in 2020.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Energy Probe Research Foundation (EP)

Reference: Exhibit C1, Tab 1, Page 6 and C1, Tab2, Page 41

Preamble: "Examples of this include support for programs such as Renewable Natural Gas, Compressed Natural Gas, and the integration of gas and electric infrastructures using technology like combined heat and power, geothermal loops and hydrogen storage and blending."

Question:

Please confirm that the programs listed except for hydrogen blending are non-utility programs.

Response

As stated on page 41 of EGD rate zone AMP, filed at Exhibit C1, Tab 2, Schedule 1, DSM and hydrogen blending are currently included as rate-regulated activities for the purpose of this Asset Management Plan. The regulatory treatments of the other programs noted in this question vary, and are described below.

RNG:

- With respect to Renewable Natural Gas ("RNG") facilities required to inject RNG into the gas distribution system will be utility assets, whereas any assets created for the purpose of upgrading raw biogas to pipeline quality RNG will be treated as non-utility assets consistent with the OEB's EB-2017-0319 Decision and Order.

Geothermal Energy Services:

- Legacy EGD also submitted a proposal to the Board in 2018 that called for geothermal ground source loops that would displace natural gas consumption to be included as part of utility rate base as a greenhouse gas emission strategy. This proposal included a non-utility element that would apply to situations where the service was provided to those without access to natural gas distribution services. This proposal was part of the EB-2017-0319 submission which was subsequently held in abeyance given the cancellation of the provincial government's Green Energy Fund initiatives.

CNG:

- This business activity has been included as part of EGD’s regulated utility as an ancillary business activity and been subject to the imposition of imputed revenues in the event that the program does not achieve the utility’s regulated rate of return in any particular year.

CHP:

- Enbridge Gas actively supports the adoption of CHP facilities.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Energy Probe Research Foundation (EP)

Reference: Exhibit C1, Tab 1, Pages 8 to 10

Question:

Were any financial constraints, such as earnings per share or customer rate impacts such as maximum rate increases, used as constraints in the preparation of the USP? If there were, please list them. If not, please explain why not.

Response

The financial constraints mentioned above were not considered as constraints in the preparation of the USP. Please see Exhibit I.CME.1 part (b) for examples of the factors that were taken into consideration when developing the Asset Management Plans for both EGD and UG.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Energy Probe Research Foundation (EP)

Reference: Exhibit C1, Tab 1, Page 22

Preamble: *“The budgets are reviewed at successively higher levels of management, with modifications made on an iterative basis as required. A final budget for each area is endorsed by the accountable Vice President responsible for each area.”*

Question:

Please provide a table listing each level of management that reviews the budget and the types of modifications that each level of management makes.

Response

The process for O&M budget creation begins at the manager level, working closely with Finance. The most detailed review of the budget happens at the management level and each subsequent review/approval is at a higher level. Potential modifications include FTE adjustments and program additions/reductions. Please see the table below:

Level of Management	Action	Description/Modifications
Manager	Create, Review, Modify	Manager works with Finance to create initial budget.
Director	Review, Modify	Director reviews submission from Manager and makes modifications. Once changes are made the Director approves.
VP	Review, Modify, Final Approval for Functional Area	VP reviews submission from Director and makes modifications. Once changes are made the VP approves.
President	Review, Modify, Final Approval for Entire Company	President reviews submission from VP's and makes modifications. Once changes are made the President provides final approval.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Energy Probe Research Foundation (EP)

Reference: Exhibit C1, Tab 1, Pages 23 and 27

Preamble: *"The consolidated O&M budget is then consolidated by Finance with the broader Company budget and is reviewed and approved by the Company's Senior Executive management team."*

"The consolidated budget and LRP is then reviewed and approved by the Company's senior executive management team."

Question:

a) Does the Company's Senior Executive management team in the text refers to Enbridge Inc. management or to Enbridge Gas Inc. management team?

b) Please file a copy of the consolidated 2019 budget that was presented by Finance to the Company's Senior Executive Team.

Response

a) The Company's Senior Executive Management Team in the text refers to Enbridge Gas Inc.'s Management Team.

b) The Company declines to provide a copy of the 2019 Budget package given that it has no impact on 2019 rates or this application.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Energy Probe Research Foundation (EP)

Reference: Exhibit C1, Tab 1, Page 23

Preamble: "*The Company's capital budget process ensures that capital is allocated in a way that maximizes the value of life cycle-based capital while mitigating risk to the lowest practical level.*"

Question:

What is *"life cycle-based capital"* and how is its value maximized?

Response

Life cycle-based capital is the capital spent on assets across its life cycle stages identified as Acquire/Create, Utilize, Maintain, and Renew/Retire. Options to mitigate risk or pursue opportunities are considered at each life cycle stage as short or long term solutions. Value-based decisions are made to manage cost, risk and performance in relation to the specific asset and the total asset portfolio.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Energy Probe Research Foundation (EP)

Reference: Exhibit C1, Tab 1, Pages 24, 27 and 34

Question:

a) What is LRP and how does it relate to the USP?

b) If the LRP and the USP are related please file the LRP

Response

a) LRP stands for Long Range Plan, which represents the longer term financial forecast, beyond the budget year, typically the latter years of the plan.

   As noted in section 3.1 in the USP, filed at Exhibit C1, Tab 1, Schedule 1, the Budget and LRP is a component of the USP. The budget and LRP balance the need to maintain safe and reliable operations that meet the demands of current and new ratepayers, while ensuring Enbridge Gas's financial viability. The Asset Management Plan underpins the Capital Expenditures for each year of the 10 year plan, which is reflected, along with a portion of the O&M costs, in the LRP, which in turn supports the USP.

b) Enbridge Gas declines to provide the LRP given it is not relevant to the relief requested as part of 2019 rates.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Energy Probe Research Foundation (EP)

Reference: Exhibit C1, Tab 1, Page 28 and Exhibit C1, Tab 2, Page 89

Question:

a) What is the significance of Lifetime Risk Return on Investment?

b) Please provide a numerical example of the calculation using NPS 30 Don River Replacement Project numbers.

Response

a) Please see Exhibit I.VECC.12.

b)

$$\text{LRROI} = \frac{\text{Discounted Lifetime Risk Reduction}}{\text{Total Net Capital Investment}}$$

Equation 1: LRROI Calculation

$$\text{Discounted Lifetime Risk Reduction} = (\text{Safety Risk Mit} \times \text{Useful Life}) + \left(\text{Fin Risk Mit} \times \frac{1-(1+\text{pretax WACC*})^{-\text{useful life}}}{\text{pretax WACC}}\right) + \left(\text{CSAT Risk Mit} \times \frac{1-(1+\text{pretax WACC})^{-\text{useful life}}}{\text{pretax WACC}}\right)$$

**WACC: Weighted Average Cost of Capital*

Equation 2: Discounted Lifetime Risk Reduction

Values for variables used Equation 2 are provided below:

Variables	Values for Project 6423
Safety Risk Mitigation	47,376
Fin Risk Mitigation	114,815
CSAT Risk Mitigation	74,956
Useful Life (Years)	70
Pretax WACC	0.062147

By applying the values in the above table to **Equation 2**, Discounted Lifetime Risk Reduction is $6,325,040. As the Total Net Direct Capital is $26,864,009 [Exhibit C1, Tab 2, Schedule 1, page 699], according to **Equation 1**, the LRROI is 24. The slight discrepancy between the LRROI shown here versus the value published in Exhibit C1, Tab 2, Schedule 1, page 699 is due to a change in the Total Net Direct Capital at the time of the filing.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Energy Probe Research Foundation (EP)

Reference: Exhibit C1, Tab 1, Schedule 1, Page 57, Figures 12&13

Question:

a) Please clarify if the PI shown in the Figures is based on gross cost or net cost (less CIAC).

b) For Figures 12 and 13 please provide the "Best Fit" Lines and provide the equations.

c) Please explain and discuss the trends in PI for the Project and Rolling Portfolios for Union and EGD.

d) Please provide the historic 2015+ and current approved system expansion projects for EGD and Union with summary data such as location, cost, customer additions etc.

e) Please discuss the outlook for system expansion projects for each rate Zone. Delineate projects using SES and Government support.

f) How much will be invested in SE during the Deferred rebasing period 2020-2025? Please reconcile to the data in the Utility System Plan.

Response

a) The PI shown in figures 12 and 13 are based on net cost (less CIAC).

b) Please see below the best fit lines and the equation for Figures 12 and 13.

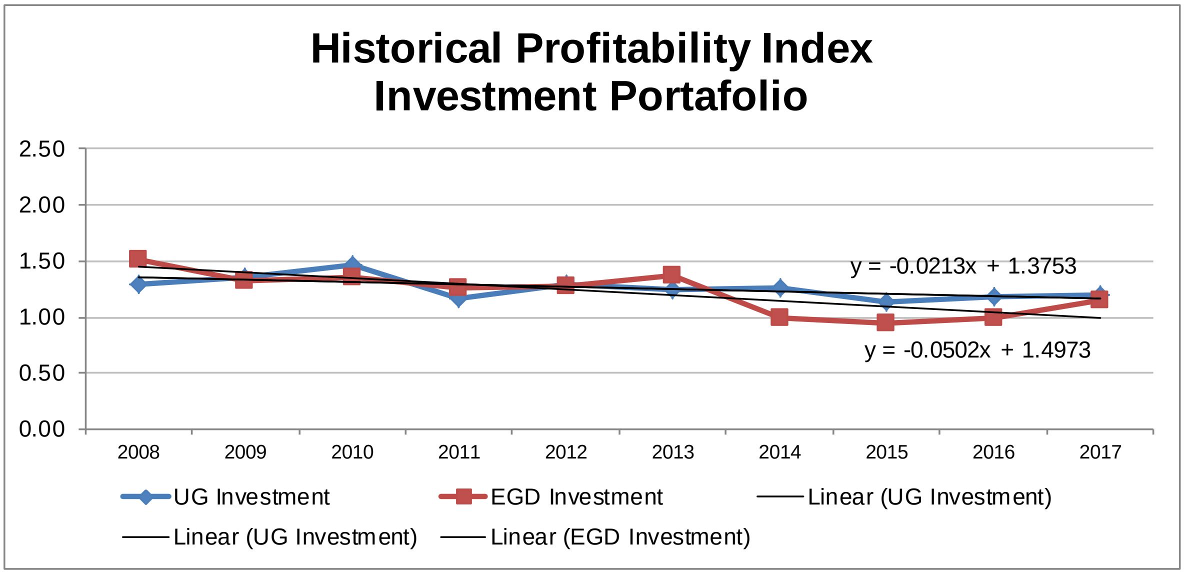

Figure 12

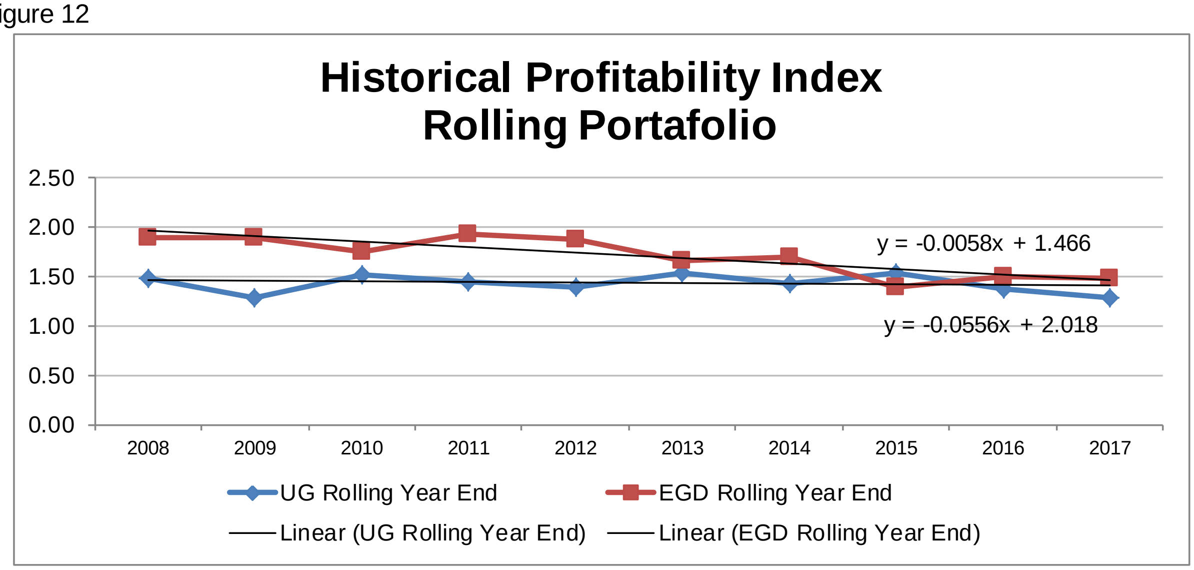

Figure 13

c) Figure 12 shows the Investment Portfolio Trend, where the slope of the best fit line for both the EGD and Union rate zones are negative, which suggests that the PI is trending down over time.

Figure 13 shows the Rolling Project Portfolio Trend, where the slope of best fit lines for the EGD and Union rate zones are negative, which suggests that their portfolio PI is trending downwards.

d) The rolling and investment portfolios include all of the distribution expansion projects completed by the company. These projects could be as simple as a 20 meter NPS 2 plastic main extension to 5 km steel NPS 8 reinforcement project. As such it is not practical to provide a list of all of the projects that are included in the rolling and investment portfolios.

e) Enbridge Gas has and will continue to manage its system expansion projects such that the Profitability Index ("PI") requirements of the Board's E.B.O. 188 economic feasibility guideline are met with respect to each of the Company's rate zones. For projects defined as Community Expansion Projects, the Company will apply the System Expansion Surcharge in compliance with the OEB's EB-2017-0147 Decision and any other relevant decision of the Board. In cases where a community expansion project is to receive financial support either through the former Natural Gas Grant Program or under the auspices of Bill 32, the Access to Natural Gas Act, 2018 and its accompanying regulation (Ontario Regulation 24/19) the funds provided under either of these programs will serve as contributions in aid of construction, effectively reducing the capital cost of these projects such that they achieve a PI of 1.0. Should the requirements of Bill 32 change, the Company will revise its applicable policies so as to accommodate and be in compliance with such changes.

f) To confirm, the deferred rebasing period is 2019 – 2023. As shown on pages 40 and 41, figure 7 and 8 respectively in the USP, filed at Exhibit C1, Tab 1, Schedule 1, system access investment is approximately $622M for EGD and $493M for Union.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Energy Probe Research Foundation (EP)

Reference: Exhibit C1, Tab 2, Pages 41and 42

Preamble: *"The overall portfolio has an LRROI of 119%. The breakdown by asset class has been summarized in Table 1.9-1. While different asset classes have higher or lower LRROI values, the value of the lifetime risk reduced is greater than the capital investment."*

Question:

a) Please explain the significance of LRROI of 119% for the overall portfolio. What should the OEB conclude from that number?

b) In Table 1.9-1 Storage has the highest LRROI of 284%. Does that mean that Storage is the most profitable asset class? Please show how the 284% number was calculated.

c) In Table 1.9-1 Pipe has the lowest LRROI of 41%. Does that mean that Pipe is the least profitable asset class? Please explain how the 41% number was calculated.

Response

a) Based on an LRROI of 119% for the overall portfolio, the OEB should conclude that the value of Lifetime Risk reduced is greater than the capital investment for such risk reduction. For more details, please refer to section 1.9, page 42 in the EGD rate zone's AMP, filed at Exhibit C1, Tab 2, Schedule 1

b) LRROI is not used to measure profitability. Storage having the highest LRROI means that the ratio of risk mitigation to capital requirements for this asset class is the highest, or per dollar of capital, the storage asset class is able to mitigate the most risk compared to the other asset classes. As described in section 4.2.5, page 89 in the EGD rate zone's AMP, filed at Exhibit C1, Tab 2, Schedule 1, the LRROI was calculated using the equations below:

Lifetime Risk Return on Investment (LRROI) is used to inform optimization where the risk mitigated by a capital investment is normalized by the net direct capital required. LRROI is a measure indicating the efficiency with which risk is reduced across all asset classes. It is calculated using **Equation 1**. The Discounted Lifetime Risk Reduction is calculated using **Equation 2** and represents the present value of the risk reduction over the useful life of the asset. Customer satisfaction and financial risk are discounted over the life of the asset, while safety risk is not, as it is of paramount importance.

$$\text{LRROI}=\frac{\text{Discounted Lifetime Risk Reduction}}{\text{Total Net Capital Investment}}$$

Equation 1: LRROI Calculation

$$\text{Discounted Lifetime Risk Reduction}=(\text{Safety Risk Mit}\times\text{Useful Life})+\left(\text{Fin Risk Mit}\times\frac{1-(1+\text{pretax WACC*})^{-\text{useful life}}}{\text{pretax WACC}}\right)+\left(\text{CSAT Risk Mit}\times\frac{1-(1+\text{pretax WACC})^{-\text{useful life}}}{\text{pretax WACC}}\right)$$

**WACC: Weighted Average Cost of Capital*

Equation 2: Discounted Lifetime Risk Reduction

c) LRROI is not used to measure profitability. Pipe's LRROI of 41% indicates that the capital requirements for the pipe asset class exceed the risk mitigated based on the portfolio of work. Please refer to (b) for the calculation of LRROI.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Energy Probe Research Foundation (EP)

Reference: Exhibit C1, Tab 2, Page 44, Table 19-3

Question:

Please explain how the Total Overhead numbers were determined.

Response

Please see Exhibit I.STAFF.32, part (c).

ENBRIDGE GAS INC.
Answer to Interrogatory from
Energy Probe Research Foundation (EP)

Reference: Exhibit C1, Tab 2, Schedule 1, Page 45, Table 1.9-5: ICM-Eligible Capital Projects

Question:

a) Please explain the relationship between the information in this table and the ICM project information in Exhibit B1, Tab 2.

b) Please provide a consolidated schedule showing approved and forecast ICM projects over the 5-year deferred rebasing period with summary data on costs and in-service dates.

Response

a) The information in Table 1.9.5 identifies discrete and material capital projects in the EGD rate zone, and includes the NPS 30 Don River Replacement ICM project and potential future ICM projects. The information in Exhibit B1, Tab 2 discusses the evidence in support of the ICM funding requests and includes the business case summary for the NPS 30 Don River Replacement ICM project.

b) A list of potential ICM projects is filed in Table 6, page 49 at Exhibit C1, Tab 1, Schedule 1.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Energy Probe Research Foundation (EP)

Reference: Exhibit C1, Tab 2, Page 45, Table 19-5

Question:

The information in the table indicates that the driver for the NPS 20 Don River Relocation project is “third party relocation”. Does Enbridge have a cost sharing agreement with the “third party”. If the answer is yes, what is the sharing ratio? If the answer is no, please explain why not.

Response

Enbridge Gas is currently in discussions with the third party stakeholder to determine what type of cost sharing mechanism and agreement will apply to this third party relocation request.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Energy Probe Research Foundation (EP)

Reference: Exhibit C1, Tab 2, Page 58, Figure 3.3-1

Question:

Should the OEB be concerned that 9.1 Monitoring Measurement Risk and Evaluation and 9.2 Internal Audit have been rated as low maturity by KPMG?

Response

In the ISO framework, 9.1 and 9.2 is focused around monitoring of the overall asset management strategy, plans, processes and KPI's as opposed to "asset risk and condition monitoring" which is captured in element 6. These elements typically mature after an organization has gone through several annual cycles and has implemented the defined strategy, organization and processes. The low maturity rating is expected given the time of the assessment.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Energy Probe Research Foundation (EP)

Reference: Exhibit D1, Tab 1, Schedule 1, Page 22

Preamble: The Question to Residential customers regarding higher rates for infrastructure replacement was:

"*In considering its five-year investment plan Enbridge Gas Distribution estimates that it will need to increase investments to keep up with aging infrastructure and still maintain the current level of reliability and safety it delivers to its customers. It is estimated that the average residential customer bill will need to increase by 3% or $2 per month over the next 5 years to maintain current levels of safety and reliability. This increase would start in 2019 and apply until 2023. So, by the end of 2023 residential customers will pay $10 more per month compared to what they pay now, to cover these increased capital investments.*"

Question:

a) Please confirm this question relates to Sustainment Capital Investment under the CIR Plan 2020-2025.

b) What information was provided to the respondents as context for the question? Please be specific.

c) Why does the CIR Plan not provide sufficient capital for sustainment? Please reply in detail.

d) Please provide the proposed budgets that underpin this question.

e) Please provide the current level of reliability and the level in 2025 based on measurable parameters.

f) Will there be offsetting OM&A cost reductions from the investment? Please delineate.

Response

a),c),d),e),f) The capital investment plan underpinning the rate impact in the customer engagement was based on a high level estimate at the time of the study and does not reflect the CIR plan for 2020 to 2025.

b) The preamble provided above was read to residential customers as context for this question.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Energy Probe Research Foundation (EP)

Reference: Exhibit D1, Tab 1, Schedule 1, Page 24

Preamble: The following question was put to Residential Customers:

> "*As you may know, on January 1, 2017 the Ontario government is planning to introduce a Cap and Trade system to help reduce greenhouse gas emissions in Ontario. Customers will pay a cost related to the amount of greenhouse gases they emit, such as from the use of fossil fuels.*
> *The government plans to invest these cap and trade proceeds into various initiatives that reduce greenhouse gases such as renewable sources of energy, public transportation, electric vehicle incentives, and energy conservation programs. Initially, the government expects costs to be about $7 per month for each natural gas customer for home heating, but the exact amounts next year and in future years is not yet known. Some estimates have indicated that the cost could increase by roughly 50 percent by 2023.*"

Question:

a) Were Residential Customers aware that the Cap and Trade charge was added to their bills? Please provide data on the level of awareness.

b) Has EGI canvassed its customers following the cancellation of the Cap and Trade and introduction of the Federal Carbon Tax in April 2019? If so please provide the results.

Response

a) The specific question asking if residential customers were aware that the Cap and Trade charge was added to their bills was not asked. Customers were asked if they were aware that starting in 2017 customers would be paying on average more to cover costs associated with Cap and Trade. Residential customers would pay on average $7 more per month – 46% were aware, General Service would pay $36 more per month on average – 36% were aware, Large Volume Customers (various unit rate increases) – 74% were aware, and Rate 6 Business customers would pay an additional 15% increase per month – 31% were aware.

b) No.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Energy Probe Research Foundation (EP)

Reference: Exhibit D1, Tab 1, Schedule 1, Pages 25 and 26

Question:

“There are a couple of ways in which Enbridge Gas can help to lower customer costs to offset this cap and trade cost. One way is to offer conservation programs (such rebates and incentives) to encourage customers to make changes to their home to reduce their household natural gas consumption. Another way is for Enbridge to invest in renewable energy sources that will reduce greenhouse gas emissions across the network and offset the amount of cap and trade costs to customers overall.

SOME PEOPLE SAY there is not much more they can do to make their home more energy efficient and therefore they may not be able to lower the cap and trade cost they pay. They are more likely to see savings based on investments Enbridge Gas could make in renewable energy that will reduce the cap and trade costs to customers across the network.

OTHER PEOPLE SAY there is more they can do to make their home more energy efficient and they would prefer to have access to rebates and incentives to help them do that to lower the cap and trade cost they pay rather than rely on investments in renewable energy by Enbridge Gas to lower cap and trade cost across the network.”

a) Which of the above questions was put to residential customers?

b) What information was provided to the respondents as context for the question? Be specific such as relative costs and bill impacts.

c) Given the OEB decision on RNG is the question no longer accurate? Please discuss.

Response

a) The text provided above refers to two separate questions asked in the residential surveys:

Question 9:

There are a couple of ways in which Enbridge Gas can help to lower customer costs to offset this cap and trade cost. One way is to offer conservation programs (such rebates and incentives) to encourage customers to make changes to their home to reduce their household natural gas consumption. Another way is for Enbridge to invest in renewable energy sources that will reduce greenhouse gas emissions across the network and offset the amount of cap and trade costs to customers overall.

Generally speaking, would you prefer to see Enbridge…? (Read list)

Invest in conservation programs to help customer reduce their consumption
Invest in renewable energy sources that will reduce the overall network's consumption
Both
Neither
Don't know (Read) [Anchor]

Question 10:

Some people say [ROTATE STATEMENT 1 AND 2] [STATEMENT 1] there is not much more they can do to make their home more energy efficient and therefore they may not be able to lower the cap and trade cost they pay. They are more likely to see savings based on investments Enbridge Gas could make in renewable energy that will reduce the cap and trade costs to customers across the network. Other people say [STATEMENT 2] there is more they can do to make their home more energy efficient and they would prefer to have access to rebates and incentives to help them do that to lower the cap and trade cost they pay rather than rely on investments in renewable energy by Enbridge Gas to lower cap and trade cost across the network. Which is closer to your point of view? Are you… (Read list)

More likely to see savings based on renewable energy investments across the network

More likely to see savings based on making your home more energy efficient
Don't know (Read) [Anchor]

b) The context provided for each question is detailed in the previous response.

c) Please see Exhibit I.EP.34, part b) and c).

ENBRIDGE GAS INC.
Answer to Interrogatory from
Energy Probe Research Foundation (EP)

Reference: Exhibit D1, Tab 1, Schedule 1, Page 29

Preamble: The following question was put to Residential Customers:

> *"As you may know, Renewable natural gas (RNG), or bio methane gas or biogas, is a type of renewable gas that is carbon neutral, thus it is better for the environment than conventional natural gas. It is a sustainable fuel that is created by converting organic material such as municipal green bin collection waste (ie. vegetable peelings), farm crop residue, gas from water treatment plants and even landfill gas that is captured and cleaned to the same quality level as natural gas. Renewable natural gas could be produced in Ontario and put into the existing natural gas distribution system. It would be compatible with all your natural gas appliances so there would be no lifestyle change for households. Renewable natural gas helps reduce greenhouse gas emissions by displacing conventional natural gas. Investing in renewable natural gas can start with modest levels of blending renewable energy with conventional energy.*
> *Think of this like the 2% blending of ethanol in gasoline. This level of renewable blending is estimated to cost customers approximately $1.60 per month. Over time, it is expected the cost of renewable natural gas will decline, making renewable natural gas less expensive than conventional natural gas in the long-term for customers."*

Question:

a) Please provide the basis of the Calculation of the $1.60 per month.

b) Is this question accurate, given the OEB decision on RNG? Please discuss.

c) Is it still relevant given the Government Policy on RNG? Please discuss.

Response

a) The $1.60 per month RNG price premium was based on 2% RNG blending by volume in EGD's supply gas supply for residential customers, and assumed an average price of $16/GJ for RNG commodity price at the time the analysis was done.

b), c) On November 29, 2018 the province released A Made-in-Ontario Environment Plan, Ontario's new plan to preserve and protect our environment for future generations. On page 33 of the plan the province states: "Require natural gas utilities to implement a voluntary renewable natural gas option for customers."

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ENBRIDGE GAS INC.
Answer to Interrogatory from
Energy Probe Research Foundation (EP)

Reference: Exhibit D1, Tab 1, Schedule 1, Page 31

Preamble: *"In each of the customer groups, willingness to pay even more for the additional blending of renewable natural gas into the existing natural gas network is low. In terms of residential customers, only about one third (36%) would be willing to pay more (above the base increase detailed in the previous question)."*

Question:

a) Was this result available at the time of the RNG proceeding?

b) If so please provide the reference.

c) Why is EGI bringing this survey regarding RNG into this proceeding? Please be specific regarding the objective(s) for doing so.

Response

a) Yes, the result was available at the time of the RNG proceeding

b) The result can be found on page 31 in the customer engagement report, filed at Exhibit D1, Tab 1, Schedule 1.

c) The customer engagement done by Ipsos Public Affairs and Innovative Research Group (Exhibit D1) is filed in support of Enbridge Gas's USP and AMP planning process. As per the Board's Decision and Procedural Order No. 2 dated April 1, 2019 "customer engagement in this proceeding is only relevant to the USP and AMP planning processes, and therefore is a consideration for the review of the ICMs."

ENBRIDGE GAS INC.
Answer to Interrogatory from
Energy Probe Research Foundation (EP)

Reference: Exhibit D1, Tab 1, Schedule 1, Page 42

Preamble: *"Among Residential customers, more than half (58%) are willing to pay an increase in their bill to fund an investment. About one third (35%) of Residential customers would be willing to pay approximately $3.60 more per month for both maintaining current levels of safety and reliability and to invest in renewable natural gas. Slightly more than one in ten (14%) Residential customers would be willing to pay approximately $1.60 more per month to invest in renewable natural gas exclusively, while one in ten (9%) would be willing to pay approximately $2.00 more per month to maintain existing levels of safety and reliability."*

Question:

a) Please confirm the cited monthly bill impact of $3.60 is split between replacement infrastructure ($2.00) and RNG ($1.60).

b) What is the current comparable Bill impact for DSM/Conservation?

c) Is EGI suggesting to the Board it should charge customers for all three initiatives plus the federal Carbon Tax during the RNG Plan? If provide the monthly residential bill impact.

d) If not, please clarify exactly what EGI is proposing and the estimated bill impacts

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Response

a) Yes, the bill impact of $3.60 is split between replacement infrastructure ($2.00) and RNG ($1.60).

b) The EGD rate zone's Board-Approved 2019 DSM Budget is $66.4M. The amount budgeted for Rate 1: Residential Service customers is $38.6M for 2019.

Based on the budgeted amount of $38.6M, the annual amount a typical Rate 1 residential customer would pay for DSM is $19, which is approximately $1.6 per month.

c, d) Enbridge Gas has been investigating the introduction of a voluntary RNG program that would be designed so as to have minimal bill impacts. This initiative is consistent with and supported by the provincial governments "A Made-in-Ontario Environment Plan" (page 33), which states: "Require natural gas utilities to implement a voluntary renewable natural gas option for customers." The costs associated with the maintenance of a safe and reliable gas distribution are completely unrelated to those of a voluntary RNG program and are legitimate costs recoverable in rates. Enbridge Gas will be required to bill and remit the Federal Carbon Tax based on end user natural gas consumption regardless as to what costs are recoverable in its rates.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Energy Probe Research Foundation (EP)

Reference: Exhibit D1, Tab 2, Schedule 1, Page 54

Preamble:
- *The three most important outcomes for (Union) residential participants are "pricing" (88% top 3 issue), "safety" (67% top 3 issue) and "reliability" (65% top 3 issue). For business participants it was the exact same order ("pricing", 85% top 3 issue; "safety", 62% top 3 issue; "reliability", 60% top 3 issue).*
- *Roughly three-in-four (74%) residential and two-thirds (65%) of business participants find the price of distributing gas "reasonable". Those residential participants with large bills are less likely to find it reasonable ($120+: 65% vs. $0-79: 79% reasonable).*
- *Nearly all participants are satisfied with Union Gas' performance on safety (residential: 92%; business: 91%) and reliability (residential: 98%; business: 93%).*

Question:

a) Were the respondents asked about paying more for infrastructure replacement, Conservation/DSM and RNG? If not why was this not done? If so please provide the results.

b) Were the Respondents asked about paying the Federal Carbon Tax? If so please provide the result and compare with the comment on Page 65.
"Unpacking "lower cost", most of the codes are general but specific mentions include the delivery charge, showing the carbon tax, and senior discount".

Response

a) Most infrastructure decisions within the plan were driven by asset health and condition or by the need to meet customer demands. These specific choices are technical considerations that don't facilitate customer impact. The utility did collect customer input that informed infrastructure decisions in three ways:

1. As noted in the preamble, customers were asked to rate and rank customer outcomes;
2. Customers were asked about the general approach the utility should take to the pacing of investments; and
3. Customers were asked about the general approach the utility should take to safety standards.

Feedback on all three of these topics was considered in evaluating the portfolio of potential investments.

b) No, the respondents were not asked about the Federal Carbon Tax.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Federation of Rental-housing Providers of Ontario (FRPO)

Reference: Exhibit B1 / Tab 1 / Schedule 1/ p. 6

Preamble: EGI's evidence states: *The EGD rate zone's October 1, 2018 EB-2018-0249 rates have a Purchased Gas Variance Account ("PGVA") reference price of $163.524 103m3. The PGVA reference price is comprised of commodity, transportation and load balancing costs. In order for adjustments to gas cost rates to only capture / reflect the impacts of the plan mix change in the 2019 gas supply portfolio versus the 2018 portfolio, the cost of the 2019 portfolio is based on the October 1, 2018 QRAM PGVA reference price of $163.524 103m3. This approach ensures that the proposed rate impacts are a function of the year-over-year changes in gas supply portfolio only and net of price / cost changes that are otherwise captured through the QRAM methodology.*

Question:

Being respectful of PO No. 2 which excludes gas supply costs which are the subject of a future proceeding, we are interested in understanding the year over year changes associated with gas supply or load balancing costs that are embedded in the distribution rates.

For gas supply or load-balancing costs included in distribution rates:

a) Please provide a brief summary of the principles used to separate gas supply or load balancing costs between gas supply costs and distribution costs.
b) Please provide any changes to cost allocation methodologies, practices or assumptions from to 2018 to 2019.
c) Please provide a summary of the categories of gas supply or load balancing costs that are allocated to distribution rates.
d) Please provide a comparison of the 2018 and 2019 costs for each of those categories of cost.
e) Please explain the drivers associated with any material changes in the quantum of costs allocated to distribution rates.

Response

a) Enbridge Gas would like to highlight that gas cost rates and distribution rates are derived on a stand-alone / separate basis. As stated in the evidence at Exhibit B1, Tab 1, Schedule 1, Page 8, starting at line 3, it is for customer billing purposes that the unit rates developed to recover the elements of the gas costs which support the provision of delivery service to customers (i.e., contracted storage and associated transportation, lost and unaccounted for gas) are added to the distribution rates and recovered through the delivery charges on customers' bills. And similarly, while the distribution costs are recovered in rates primarily through the delivery rates, some distribution related costs and associated unit rates are recovered through the Company's commodity, transportation, and load balancing charges.

This Board-approved approach ensures that charges on customers' bills reflect / are based on cost causality for the services provided and that only customers who subscribed for specific services pay for the costs of those services. For example, the cost of facilitating the Sales service (i.e., system gas) supply option (which is part of the Company's distribution costs) should be recovered from customers who take the Sales service. The cost of unaccounted for gas, given it represents gas losses on the gas distribution system, should be recovered from all customers through delivery charges regardless of the type of service (i.e., Sales service, Western T-service, etc.) they are taking.

As described in evidence at Exhibit B1, Tab 1, Schedule 1, Appendix C, the EGD rate zone operated under Custom Incentive Rate ("IR") rate setting framework approved by the Board under EB-2013-0202 for the 2014 to 2018 period.

The Company used the fully allocated cost study ("FACS") to allocate the Allowed Revenue to the customer classes and develop rates to recover the Allowed Revenue based on the results of the FACS. The FACS was updated annually to reflect forecast costs and forecast cost drivers with the results being used as the starting point for rate design.

As noted above, the rates designed based on the results of the FACS (i.e., based on cost causality) have most of the distribution costs recovered through the Company's delivery rates, however, some distribution related costs are recovered from the commodity, transportation and load balancing rates (given that such distribution costs (i.e., system gas administration, bad debt commodity, or return on gas in inventory) support provisions of these services to customers). Similarly, some gas costs, storage and related transportation, and lost and unaccounted for gas (i.e., commodity) costs are recovered through the Company's delivery rates.

The EGD rate zone will adopt Price Cap IR rate setting framework for the 2019 to 2023 period. Under Price Cap IR distribution related revenues and rates are derived based on a Price Cap Index ("PCI"), which is comprised of an inflation factor, a productivity factor, and a stretch factor.

The pass through (Y-factor) costs, such as DSM and gas costs, are not subject to the PCI and are passed through to customers at cost. The pass through (Y-factor) costs reflect forecast of costs for these elements for the test year. For this reason, Enbridge Gas is able to update not only the forecast level of pass through costs but also allocations of pass through costs each year of an IR rate setting period.

b) There are no changes to cost allocation methodologies, practices, or assumptions from 2018 to 2019.

c, d, and e) The categories of gas costs that are recovered through the Company's delivery charges, as discussed above, can be found for 2019 at Exhibit F1, Tab 1, Schedule 9, Page 2, Items 3.1 to 4.1 and for 2018 at Exhibit F1, Tab 1, Schedule 4, Appendix A, Attachment 1, Items 3.1 to 4.1.

For 2019, approximately $187.8 M of the total gas cost forecast of approximately $1,598.1 M will be recovered from customers through the delivery charges.

For 2018, approximately $184.2 M of the total gas cost forecast of approximately $1,547.8 M was recovered from customers through the delivery charges.

The difference in allocated costs is driven by year-over-year change in demand / volumetric requirements and in the gas supply mix.

Exhibit F1, Tab 1, Schedule 6, pages 1 to 3 shows how distribution and gas cost unit rates are added together in order to derive the proposed delivery charge unit rates for each customer class

ENBRIDGE GAS INC.
Answer to Interrogatory from
Federation of Rental-housing Providers of Ontario (FRPO)

Reference: Exhibit B1 / Tab 1 / Schedule 1/ p. 8

Preamble: EGI's evidence states: *Similarly, the distribution costs are recovered in rates primarily from the delivery rates, however, some distribution related unit rates / costs are recovered from the Company's commodity, transportation, and load balancing charges*

Question:

Please identify the categories of distribution costs captured in each of:

a) Commodity
b) Transportation
c) Load Balancing

Response

a- c) Please see Exhibit I.FRPO.3.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Federation of Rental-housing Providers of Ontario (FRPO)

Reference: Exhibit B1 / Tab 1 / Schedule 1/ p. 8

Preamble: EGI's evidence states: *Similarly, the distribution costs are recovered in rates primarily from the delivery rates, however, some distribution related unit rates / costs are recovered from the Company's commodity, transportation, and load balancing charges*

Question:

Please provide the total forecasted cost for each of the above categories:

a) 2018
b) 2019
c) Please provide the drivers for any material difference between the two years.
d) Please provide any changes to cost allocation methodologies, practices or assumptions from to 2018 to 2019.

Response

a) Enbridge Gas would like to highlight that gas cost rates and distribution rates are derived on a stand-alone / separate basis, which was also noted in the lead-in to the response to Exhibit I.FRPO.1.

   Further, as described in Exhibit I.FRPO .1, until 2019 the Company used the fully allocated cost study ("FACS") to allocate the Allowed Revenue to the customer classes and develop rates to recover the Allowed Revenue based on the results of the FACS. The FACS was updated annually to reflect forecast costs and forecast cost drivers with the results being used as the starting point for rate design. The rates designed based on the results of the FACS (i.e. based on cost causality) have most of the distribution costs recovered through the Company's delivery rates, however, some distribution related costs are recovered from the commodity, transportation and load balancing rates. Similarly, some gas costs are recovered through the Company's delivery rates.

The total 2018 forecast distribution costs recovered through the Company's gas supply commodity, transportation, and load balancing charges are provided for each customer class in the evidence at:

Exhibit F1, Tab 1, Schedule 4, pages 1 to 11, Col. K, Line 8 to 11, and
Exhibit F1, Tab 1, Schedule 5, pages 1 to 22, Col. B, Line 8 to 11.

For 2018, approximately $42.2 M of the total forecast distribution cost of approximately $1,212.4 M was recovered from customers through the gas supply commodity, transportation, and load balancing charges.

The categories of distribution costs recovered through these charges include:

<u>For the gas supply commodity charges</u>:
system gas fee (cost of facilitating Sales (i.e., system gas) service)
commodity related working cash requirement
commodity related bad debt expense

<u>For the transportation charges</u>:
part of the transmission segment (Segment A) of the GTA project(1)

<u>For the load balancing charges</u>:
carrying cost of gas in inventory
part of the transmission segment (Segment A) of the GTA project(1)

Note (1): The OEB approved Segment A of the GTA project for Enbridge Gas to improve diversity and security of its upstream supplies, to facilitate the shift in gas supplies from long haul to short haul, and to accommodate more supply purchases at Dawn. The recovery reflects cost causality / usage of Segment A.

b) The total 2019 forecast distribution costs and associated unit rates recovered through the Company's gas supply commodity, transportation, and load balancing charges are provided for each customer class in the evidence at:

Exhibit F1, Tab 1, Schedule 5, pages 1 to 22, Col. G and J, Line Nos 8 to 11.

The Price Cap Index adjustment of 1.07% on the 2018 amount of approximately $42.2 M results in approximately $0.45 M of additional revenue to be recovered from customers in 2019.

Exhibit F1, Tab 1, Schedule 6, pages 1 to 3 shows how distribution and gas cost unit rates are added together in order to derive the proposed unit rates for gas supply commodity, transportation, and load balancing charges for each customer class.

c) As described in evidence at Exhibit B1, Tab 1, Schedule 1, Appendix C, the EGD rate zone will adopt Price Cap IR rate setting framework for the 2019 to 2023 period. Under Price Cap IR distribution related revenues and rates are derived based on a Price Cap Index ("PCI"), which is comprised of an inflation factor, a productivity factor, and a stretch factor.

   Accordingly, the year-over-year change in these costs for the 2019 to 2023 IR period will be a function of the Price Cap Index as shown at Exhibit F1, Tab 1, Schedule 5, pages 1 to 22, Line 8 to 11.

d) Under Price Cap IR distribution related revenues and rates are derived based on a Price Cap Index (i.e., formulaic derivation). Consequently, cost allocation will not be carried out for these cost elements during the 2019 to 2023 IR period.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Federation of Rental-housing Providers of Ontario (FRPO)

Reference: Exhibit B1 / Tab 1 / Schedule 1/ p. 28-29

Preamble: EGI's evidence states: *Enbridge Gas also proposes to build into rates the surplus Dawn-Parkway capacity of 30,393 GJ/d resulting from the 2017 Dawn-Parkway Expansion project (EB-2015-0200). As part of the 2017 Dawn-Parkway proceeding, parties agreed Union would credit the Lobo D/Bright C/Dawn H Compressor Project Deferral Account (Account No. 179-144) for revenue generated from the 30,393 GJ/d of surplus capacity. Enbridge Gas anticipates that this surplus capacity will be sold long-term beginning on November 1, 2018 and for the remainder of the deferred rebasing period.*

Question:

For the Dawn-Parkway system

a) What, if any, capacity was turned back in 2018?
b) How much additional capacity was sold in 2018?
c) What was the 2018/19 winter design capacity of the system?
d) What was the 2018/19 design day demand on the system?
e) What if, any capacity, is scheduled for turnback in 2019?

Response

a) 159,978 GJ/d of Dawn to Parkway capacity was turned back in 2018. This total included 70,009 GJ/d of capacity for TCE Halton Hills as was allowed in the Parkway Delivery Obligation Settlement Agreement (EB-2013-0365). However, this 70,009 GJ/d of capacity is not available to be re-sold as it is required to serve TCE Halton Hills demand.

b) 42,378 GJ/d of Dawn to Parkway capacity was sold beginning November 1, 2018.

c) 7873 TJ/d

d) 7747 TJ/d

e) 336,586 GJ/d of Parkway to Dawn capacity was turned back effective March 31, 2019 and 56,021 GJ/d of Dawn to Parkway capacity will be turned back effective November 1, 2019.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Federation of Rental-housing Providers of Ontario (FRPO)

Reference: Exhibit B1 / Tab 1 / Schedule 1/ p. 28-29

Preamble: EGI's evidence states: *Enbridge Gas also proposes to build into rates the surplus Dawn-Parkway capacity of 30,393 GJ/d resulting from the 2017 Dawn-Parkway Expansion project (EB-2015-0200). As part of the 2017 Dawn-Parkway proceeding, parties agreed Union would credit the Lobo D/Bright C/Dawn H Compressor Project Deferral Account (Account No. 179-144) for revenue generated from the 30,393 GJ/d of surplus capacity. Enbridge Gas anticipates that this surplus capacity will be sold long-term beginning on November 1, 2018 and for the remainder of the deferred rebasing period.*

Question:

Please provide the EGI index of customers for the Dawn-Parkway system as of Jan. 1, 2019 including totals to each delivery point.

a) What is the forecasted revenue in 2019 for C1 contracts that were in place January 1, 2019?

Response

Please see Attachment 1 for the original January 1, 2019 Transportation Index of Customers as posted on the Union Gas website. Please see Attachment 2 for the January 1, 2019 Transportation Index of Customers showing only those contracts on the Dawn-Parkway system with subtotals for each contracted path.

a) The forecasted revenue in 2019 for the C1 contracts that were in place January 1, 2019 is $15.3 million.

January 2019

Customer Name	Contract Identifier	Receipt Point	Delivery Point	Quantity (GJ)	Start Date	End Date	Negotiated Rate	Affiliate
St. Lawrence Gas Company, Inc.	C10076	Parkway	Dawn	10,785	01-Apr-07	31-Mar-21	N	Y
Greenfield Energy Centre LP	C10083	Dawn	Dawn-Vector	92,845	01-Mar-08	31-Oct-21	N	N
Energir, L.P. by its General Partner Energir Inc	C10087	Parkway	Dawn	100,000	01-Apr-11	31-Mar-19	N	N
TransCanada PipeLines Limited	C10097	Dawn	Dawn (TCPL)	500,000	01-Nov-10	31-Oct-21	N	N
York Energy Centre LP	C10102	Dawn	Parkway	11,654	01-Apr-12	31-Oct-22	N	N
Bluewater Gas Storage, LLC	C10105	Bluewater	Dawn	123,000	01-Nov-13	31-Oct-23	N	N
Emera Energy Limited Partnership	C10106	Ojibway	Dawn	21,016	01-Nov-15	31-Oct-20	N	N
Emera Energy Limited Partnership	C10107	Kirkwall	Dawn	73,745	01-Nov-15	31-Oct-21	N	N
Emera Energy Limited Partnership	C10108	Kirkwall	Dawn	26,335	01-Apr-15	31-Mar-21	N	N
Seneca Resources Company, LLC	C10109	Kirkwall	Dawn	388,261	01-Nov-16	31-Mar-23	Y	N
Rover Pipeline LLC	C10113	Ojibway	Dawn	36,927	01-Nov-17	31-Oct-25	N	N
TransCanada PipeLines Limited	C10114	Parkway	Dawn	516,787	01-Nov-17	31-Oct-20	N	N
TransCanada PipeLines Limited	C10115	Parkway	Dawn	42,202	01-Nov-17	31-Oct-22	N	N
Husky Oil Operations Limited	HUB002T0343	Dawn	Parkway	1,200	01-Dec-18	28-Feb-19	Y	N
BP Canada Energy Group ULC	HUB040E60	Dawn	Parkway	1,277	01-Nov-18	31-Oct-19	N	N
BP Canada Energy Group ULC	HUB040E61	Dawn	Parkway	3,053	01-Nov-18	31-Oct-19	N	N
BP Canada Energy Group ULC	HUB040E62	Dawn	Parkway	10,789	01-Nov-18	31-Oct-19	N	N
Vermont Gas Systems, Inc.	HUB100T0047	Dawn	Parkway	10,551	01-Nov-18	31-Mar-19	Y	N
Vermont Gas Systems, Inc.	HUB100T0048	Dawn	Parkway	5,275	01-Nov-18	31-Mar-19	Y	N
Shell Energy North America (Canada) Inc.	HUB164T0122	Dawn	Ojibway	20,000	01-Dec-18	31-Mar-19	Y	N
Just Energy Ontario L.P.	HUB250T004	Dawn	Parkway	5,275	01-Nov-18	31-Mar-19	Y	N
Just Energy Ontario L.P.	HUB250T005	Dawn	Parkway	1,055	01-Nov-18	31-Mar-19	Y	N
Tidal Energy Marketing Inc.	HUB305T168	Ojibway	Dawn	10,551	01-Nov-18	31-Mar-19	Y	Y
Ontario Power Generation Inc.	HUB335T0015	Parkway	Dawn	2,650	06-Nov-18	31-Oct-19	Y	N
Suncor Energy Marketing Inc.	HUB345T0418	Dawn	Parkway	3,587	01-Nov-18	31-Mar-19	Y	N
Suncor Energy Marketing Inc.	HUB345T0419	Dawn	Parkway	2,638	01-Nov-18	31-Mar-19	Y	N
Suncor Energy Marketing Inc.	HUB345T0423	Dawn	Parkway	10,551	01-Dec-18	31-Mar-19	Y	N
Emera Energy Limited Partnership	HUB380T0263	Ojibway	Dawn	13,188	01-Jan-19	31-Mar-19	Y	N
Bluewater Gas Storage, LLC	HUB507T133	Dawn	Dawn-Vector	123,001	01-Nov-18	31-Mar-19	Y	N
NextEra Energy Marketing, LLC	HUB526T0005	Dawn	Parkway	2,639	01-Nov-18	31-Mar-19	Y	N
NextEra Energy Marketing, LLC	HUB526T0006	Dawn	Parkway	5,275	01-Nov-18	31-Mar-19	Y	N
EDF Trading North America, LLC	HUB561T0951	Dawn	Parkway	31,652	01-Nov-18	31-Mar-19	Y	N
EDF Trading North America, LLC	HUB561T0990	Dawn	Parkway	15,826	01-Nov-18	31-Mar-19	Y	N
Hartree Partners, LP	HUB566T0301	St. Clair	Dawn	10,551	01-Nov-18	31-Mar-19	Y	N
MIECO INC.	HUB615T0144	St. Clair	Dawn	10,551	01-Nov-18	31-Mar-19	Y	N
Twin Eagle Resource Management Canada, LLC	HUB618T0083	Dawn	Parkway	3,000	01-Nov-18	31-Mar-19	Y	N
Castleton Commodities Merchant Trading L.P.	HUB623T0120	Dawn	Parkway	2,638	01-Nov-18	31-Mar-19	Y	N
Castleton Commodities Merchant Trading L.P.	HUB623T0123	Dawn	Parkway	5,275	01-Nov-18	31-Mar-19	Y	N
Castleton Commodities Merchant Trading L.P.	HUB623T0124	Dawn	Parkway	5,275	01-Nov-18	31-Mar-19	Y	N
Castleton Commodities Merchant Trading L.P.	HUB623T0125	Dawn	Parkway	5,275	01-Nov-18	31-Mar-19	Y	N
Castleton Commodities Merchant Trading L.P.	HUB623T0126	Dawn	Parkway	5,275	01-Nov-18	31-Mar-19	Y	N
Castleton Commodities Merchant Trading L.P.	HUB623T0130	Dawn	Parkway	5,275	01-Jan-19	31-Jan-19	Y	N
Castleton Commodities Merchant Trading L.P.	HUB623T0131	Dawn	Parkway	21,101	01-Jan-19	31-Jan-19	Y	N
Basic Energy Inc.	HUB750T001	Dawn	Parkway	180	01-Nov-18	31-Mar-19	Y	N
Energir, L.P. by its General Partner Energir Inc	M12007D	Dawn	Parkway	21,021	01-Nov-91	31-Oct-19	N	N
1425445 Ontario Limited o/a Utilities Kingston	M12077	Dawn	Parkway	6,322	01-Apr-04	31-Mar-21	N	N
Stelco Inc.	M12085	Dawn	Parkway	11,087	16-Sep-14	31-Oct-20	N	N
Energir, L.P. by its General Partner Energir Inc	M12092	Dawn	Parkway	35,000	01-Nov-06	31-Oct-19	N	N
Energir, L.P. by its General Partner Energir Inc	M12109	Dawn	Parkway	65,000	01-Nov-07	31-Oct-27	N	N
Goreway Station Partnership by its managing partner Goreway Power Station Holdings ULC	M12110	Dawn	Parkway	140,000	01-Nov-07	31-Oct-28	N	N
Vermont Gas Systems, Inc.	M12119	Dawn	Parkway	20,000	01-Nov-07	31-Oct-21	N	N
Greater Toronto Airports Authority	M12120	Dawn	Parkway	7,500	01-Nov-07	31-Oct-21	N	N
St. Lawrence Gas Company, Inc.	M12126	Dawn	Parkway	10,785	01-Nov-08	31-Oct-21	N	Y

January 2019

Customer Name	Contract Identifier	Receipt Point	Delivery Point	Quantity (GJ)	Start Date	End Date	Negotiated Rate	Affiliate
Thorold CoGen L.P. by its General Partner Northland Power Thorold Cogen GP Inc.	M12129	Dawn	Kirkwall	49,500	01-Sep-09	31-Aug-29	N	N
Portlands Energy Centre L.P. by its General Partner, Portlands Energy Centre Inc.	M12130	Dawn	Parkway	100,000	13-Jan-09	31-Oct-28	N	N
Energir, L.P. by its General Partner Energir Inc	M12132	Dawn	Parkway	52,343	01-Apr-09	31-Mar-21	N	N
Ag Energy Co-operative Ltd.	M12151	Dawn	Parkway	1,247	01-Nov-08	31-Oct-20	N	N
The Narragansett Electric Company d/b/a National Grid	M12164	Dawn	Parkway	1,081	01-Nov-11	31-Oct-21	N	N
Connecticut Natural Gas Corporation	M12166	Dawn	Parkway	6,410	01-Nov-11	31-Oct-21	N	N
Ag Energy Co-operative Ltd.	M12167	Dawn	Parkway	1,900	01-Nov-11	31-Oct-21	N	N
Consolidated Edison Company of New York, Inc. and Orange and Rockland Utilities, Inc.	M12171	Dawn	Parkway	21,825	01-Nov-11	31-Oct-21	N	N
Energir, L.P. by its General Partner Energir Inc	M12172	Dawn	Parkway	22,908	01-Apr-10	31-Mar-21	N	N
Energir, L.P. by its General Partner Energir Inc	M12176	Dawn	Parkway	88,728	01-Apr-11	31-Mar-21	N	N
Central Hudson Gas & Electric Corporation (a subsidiary of CH Energy Group, Inc.)	M12182	Dawn	Parkway	5,467	01-Nov-11	31-Oct-21	N	N
York Energy Centre LP	M12184	Dawn	Parkway	76,000	01-Apr-12	31-Oct-22	N	N
Niagara Mohawk Power Corporation d/b/a National Grid	M12186	Dawn	Parkway	55,123	01-Nov-11	31-Oct-21	N	N
Vermont Gas Systems, Inc.	M12190	Dawn	Parkway	500	01-Nov-10	31-Oct-21	N	N
The Brooklyn Union Gas Company d/b/a National Grid NY	M12193	Dawn	Parkway	12,953	01-Nov-10	31-Oct-21	N	N
KeySpan Gas East Corporation d/b/a National Grid	M12194	Dawn	Parkway	17,162	01-Nov-10	31-Oct-20	N	N
Central Hudson Gas & Electric Corporation (a subsidiary of CH Energy Group, Inc.)	M12195	Dawn	Parkway	10,792	01-Nov-10	31-Oct-21	N	N
Boston Gas Company d/b/a National Grid	M12197	Dawn	Parkway	9,282	01-Nov-10	31-Oct-21	N	N
Colonial Gas Company d/b/a National Grid	M12198	Dawn	Parkway	6,475	01-Nov-10	31-Oct-21	N	N
Boston Gas Company d/b/a National Grid	M12199	Dawn	Parkway	2,158	01-Nov-10	31-Oct-21	N	N
Liberty Utilities (EnergyNorth Natural Gas) Corp.	M12200	Dawn	Parkway	4,317	01-Nov-10	31-Oct-22	N	N
Connecticut Natural Gas Corporation	M12201	Dawn	Parkway	18,077	01-Nov-10	31-Oct-21	N	N
The Southern Connecticut Gas Company	M12202	Dawn	Parkway	34,950	01-Nov-10	31-Oct-21	N	N
Yankee Gas Services Company dba Eversource Energy	M12203	Dawn	Parkway	43,116	01-Nov-10	31-Oct-21	N	N
Bay State Gas Company dba Columbia Gas of Massachusetts	M12204	Dawn	Parkway	27,803	01-Nov-10	31-Oct-22	N	N
Connecticut Natural Gas Corporation	M12206	Dawn	Parkway	9,170	01-Nov-10	31-Oct-21	N	N
The Southern Connecticut Gas Company	M12207	Dawn	Parkway	13,970	01-Nov-10	31-Oct-21	N	N
The Brooklyn Union Gas Company d/b/a National Grid NY	M12208	Dawn	Parkway	30,217	01-Nov-10	31-Oct-21	N	N
KeySpan Gas East Corporation d/b/a National Grid	M12209	Dawn	Parkway	22,772	01-Nov-10	31-Oct-21	N	N
Yankee Gas Services Company dba Eversource Energy	M12210	Dawn	Parkway	20,560	01-Nov-10	31-Oct-21	N	N
Yankee Gas Services Company dba Eversource Energy	M12212	Dawn	Parkway	5,380	01-Nov-10	31-Oct-21	N	N
The Southern Connecticut Gas Company	M12213	Dawn	Parkway	9,735	01-Nov-10	31-Oct-21	N	N
Connecticut Natural Gas Corporation	M12214	Dawn	Parkway	6,489	01-Nov-10	31-Oct-21	N	N
Suncor Energy Products Partnership Produits Suncor Energie, S.E.N.C.	M12217	Dawn	Parkway	9,585	01-Nov-11	31-Oct-21	N	N
TransCanada PipeLines Limited	M12219	Kirkwall	Parkway	88,497	01-Nov-12	31-Oct-22	N	N
TransCanada PipeLines Limited	M12220	Kirkwall	Parkway	174,752	01-Nov-13	31-Oct-23	N	N
Emera Energy Limited Partnership	M12221	Kirkwall	Parkway	36,751	01-Nov-12	31-Oct-22	N	N
Energir, L.P. by its General Partner Energir Inc	M12222	Dawn	Parkway	257,784	01-Nov-15	31-Oct-25	N	N
Vermont Gas Systems, Inc.	M12224	Dawn	Parkway	8,100	01-Nov-14	31-Oct-24	N	N
TransCanada PipeLines Limited	M12230	Kirkwall	Parkway	36,301	01-Nov-16	31-Oct-31	N	N
Energir, L.P. by its General Partner Energir Inc	M12232	Dawn	Parkway	39,507	01-Nov-16	31-Oct-31	N	N
Energir, L.P. by its General Partner Energir Inc	M12233	Dawn	Parkway	19,754	01-Nov-16	31-Oct-31	N	N
Energir, L.P. by its General Partner Energir Inc	M12237	Dawn	Parkway	85,680	01-Nov-16	31-Oct-31	N	N
Energir, L.P. by its General Partner Energir Inc	M12244	Dawn	Parkway	36,670	01-Nov-17	31-Oct-32	N	N
TransCanada Energy Ltd.	M12246	Dawn	Parkway	143,775	01-Nov-17	31-Oct-32	N	N
St. Lawrence Gas Company, Inc.	M12249	Dawn	Parkway	10,412	01-Nov-17	31-Oct-32	N	Y
1425445 Ontario Limited o/a Utilities Kingston	M12251	Dawn	Parkway	5,000	01-Nov-17	31-Oct-32	N	N
1425445 Ontario Limited o/a Utilities Kingston	M12252	Kirkwall	Parkway	1,000	01-Nov-17	31-Oct-32	N	N

January 2019

Customer Name	Contract Identifier	Receipt Point	Delivery Point	Quantity (GJ)	Start Date	End Date	Negotiated Rate	Affiliate
The Corporation of the City of Kitchener	M12253	Kirkwall	Parkway	10,000	01-Nov-17	31-Oct-32	N	N
DTE Energy Trading, Inc.	M12255	Kirkwall	Parkway	73,854	01-Nov-17	31-Oct-31	N	N
Northern Utilities, Inc.	M12256	Dawn	Parkway	42,962	01-Nov-17	31-Oct-33	N	N
Portland Natural Gas Transmission System	M12266-AS1	Dawn	Parkway	1,957	01-Nov-18	31-Oct-40	N	N
Enbridge Gas New Brunswick Limited Partnership by its General Partner, Enbridge Gas New Brunswick Inc.	M12270	Dawn	Parkway	2,650	01-Nov-18	31-Oct-40	N	Y
Boston Gas Company d/b/a National Grid	M12273	Dawn	Parkway	22,332	01-Nov-18	31-Oct-40	N	N
The Narragansett Electric Company d/b/a National Grid	M12274	Dawn	Parkway	11,349	01-Nov-18	31-Oct-40	N	N
Heritage Gas Limited	M12276	Dawn	Parkway	3,978	01-Nov-18	31-Oct-40	N	N
Enbridge Gas New Brunswick Limited Partnership by its General Partner, Enbridge Gas New Brunswick Inc.	M12277	Dawn	Parkway	112	01-Nov-18	31-Oct-40	N	Y
TransCanada PipeLines Limited	M12X004	Dawn	Parkway	50,000	01-Sep-11	31-Aug-21	N	N
TransCanada PipeLines Limited	M12X005	Dawn	Parkway	78,316	01-Sep-11	31-Aug-21	N	N
TransCanada PipeLines Limited	M12X013	Dawn	Parkway	62,695	01-Nov-12	31-Oct-23	N	N
1425445 Ontario Limited o/a Utilities Kingston	M12X015	Dawn	Parkway	5,000	01-Apr-14	31-Mar-24	N	N
Market Hub Partners Canada L.P.	M16004	Dawn	Market Hub Partners - St. Clair Pool	9,000	01-Jun-07	31-May-21	N	Y
Market Hub Partners Canada L.P.	M16004	Market Hub Partners - St. Clair Pool	Dawn	5,000	01-Jun-07	31-May-21	N	Y
Enbridge Gas Inc. (In-Franchise Customers - EGD Zone) *		Dawn	Parkway	2,917,173	01-Jan-19	31-Oct-19	N	Y
Enbridge Gas Inc. (In-Franchise Customers - EGD Zone) **		Dawn	Kirkwall	67,929	01-Jan-19	31-Oct-19	N	Y
Enbridge Gas Inc. (In-Franchise Customers - EGD Zone) ***		Parkway	Dawn	236,586	01-Jan-19	31-Mar-19	N	Y
In-Franchise Customers - Union South and North Zones		Dawn	Parkway	2,333,248	01-Nov-18	31-Oct-19	N	Y

* - comprised of former contract #'s: M12079B, M12080, M12108, M12125, M12188, M12225, M12234, M12250 & M12X006

** - comprised of former contract #'s: M12079A & M12175

*** - comprised of former contract #: C10009

January 2019

Customer Name	Contract Identifier	Receipt Point	Delivery Point	Quantity (GJ)	Start Date	End Date	Negotiated Rate	Affiliate
Emera Energy Limited Partnership	C10107	Kirkwall	Dawn	73,745	1-Nov-15	31-Oct-21	N	N
Emera Energy Limited Partnership	C10108	Kirkwall	Dawn	26,335	1-Apr-15	31-Mar-21	N	N
Seneca Resources Company, LLC	C10109	Kirkwall	Dawn	388,261	1-Nov-16	31-Mar-23	Y	N
SUBTOTAL (Kirkwall to Dawn)				**488,341**				
St. Lawrence Gas Company, Inc.	C10076	Parkway	Dawn	10,785	1-Apr-07	31-Mar-21	N	Y
Energir, L.P. by its General Partner Energir Inc	C10087	Parkway	Dawn	100,000	1-Apr-11	31-Mar-19	N	N
TransCanada PipeLines Limited	C10114	Parkway	Dawn	516,787	1-Nov-17	31-Oct-20	N	N
TransCanada PipeLines Limited	C10115	Parkway	Dawn	42,202	1-Nov-17	31-Oct-22	N	N
Ontario Power Generation Inc.	HUB335T0015	Parkway	Dawn	2,650	6-Nov-18	31-Oct-19	Y	N
Enbridge Gas Inc. (In-Franchise Customers - EGD Zone) ***		Parkway	Dawn	236,586	1-Jan-19	31-Mar-19	N	Y
SUBTOTAL (Parkway to Dawn)				**909,010**				
Thorold CoGen L.P. by its General Partner Northland Power Thorold Cogen GP Inc.	M12129	Dawn	Kirkwall	49,500	1-Sep-09	31-Aug-29	N	N
Enbridge Gas Inc. (In-Franchise Customers - EGD Zone) **		Dawn	Kirkwall	67,929	1-Jan-19	31-Oct-19	N	Y
SUBTOTAL (Dawn to Kirkwall)				**117,429**				
York Energy Centre LP	C10102	Dawn	Parkway	11,654	1-Apr-12	31-Oct-22	N	N
Husky Oil Operations Limited	HUB002T0343	Dawn	Parkway	1,200	1-Dec-18	28-Feb-19	Y	N
BP Canada Energy Group ULC	HUB040E60	Dawn	Parkway	1,277	1-Nov-18	31-Oct-19	N	N
BP Canada Energy Group ULC	HUB040E61	Dawn	Parkway	3,053	1-Nov-18	31-Oct-19	N	N
BP Canada Energy Group ULC	HUB040E62	Dawn	Parkway	10,789	1-Nov-18	31-Oct-19	N	N
Vermont Gas Systems, Inc.	HUB100T0047	Dawn	Parkway	10,551	1-Nov-18	31-Mar-19	Y	N
Vermont Gas Systems, Inc.	HUB100T0048	Dawn	Parkway	5,275	1-Nov-18	31-Mar-19	Y	N
Just Energy Ontario L.P.	HUB250T004	Dawn	Parkway	5,275	1-Nov-18	31-Mar-19	Y	N
Just Energy Ontario L.P.	HUB250T005	Dawn	Parkway	1,055	1-Nov-18	31-Mar-19	Y	N
Suncor Energy Marketing Inc.	HUB345T0418	Dawn	Parkway	3,587	1-Nov-18	31-Mar-19	Y	N
Suncor Energy Marketing Inc.	HUB345T0419	Dawn	Parkway	2,638	1-Nov-18	31-Mar-19	Y	N
Suncor Energy Marketing Inc.	HUB345T0423	Dawn	Parkway	10,551	1-Dec-18	31-Mar-19	Y	N
NextEra Energy Marketing, LLC	HUB526T0005	Dawn	Parkway	2,639	1-Nov-18	31-Mar-19	Y	N
NextEra Energy Marketing, LLC	HUB526T0006	Dawn	Parkway	5,275	1-Nov-18	31-Mar-19	Y	N
EDF Trading North America, LLC	HUB561T0951	Dawn	Parkway	31,652	1-Nov-18	31-Mar-19	Y	N
EDF Trading North America, LLC	HUB561T0990	Dawn	Parkway	15,826	1-Nov-18	31-Mar-19	Y	N
Twin Eagle Resource Management Canada, LLC	HUB618T0083	Dawn	Parkway	3,000	1-Nov-18	31-Mar-19	Y	N
Castleton Commodities Merchant Trading L.P.	HUB623T0120	Dawn	Parkway	2,638	1-Nov-18	31-Mar-19	Y	N
Castleton Commodities Merchant Trading L.P.	HUB623T0123	Dawn	Parkway	5,275	1-Nov-18	31-Mar-19	Y	N
Castleton Commodities Merchant Trading L.P.	HUB623T0124	Dawn	Parkway	5,275	1-Nov-18	31-Mar-19	Y	N
Castleton Commodities Merchant Trading L.P.	HUB623T0125	Dawn	Parkway	5,275	1-Nov-18	31-Mar-19	Y	N
Castleton Commodities Merchant Trading L.P.	HUB623T0126	Dawn	Parkway	5,275	1-Nov-18	31-Mar-19	Y	N
Castleton Commodities Merchant Trading L.P.	HUB623T0130	Dawn	Parkway	5,275	1-Jan-19	31-Jan-19	Y	N
Castleton Commodities Merchant Trading L.P.	HUB623T0131	Dawn	Parkway	21,101	1-Jan-19	31-Jan-19	Y	N
Basic Energy Inc.	HUB750T001	Dawn	Parkway	180	1-Nov-18	31-Mar-19	Y	N
Energir, L.P. by its General Partner Energir Inc	M12007D	Dawn	Parkway	21,021	1-Nov-91	31-Oct-19	N	N
1425445 Ontario Limited o/a Utilities Kingston	M12077	Dawn	Parkway	6,322	1-Apr-04	31-Mar-21	N	N
Stelco Inc.	M12085	Dawn	Parkway	11,087	16-Sep-14	31-Oct-20	N	N
Energir, L.P. by its General Partner Energir Inc	M12092	Dawn	Parkway	35,000	1-Nov-06	31-Oct-19	N	N
Energir, L.P. by its General Partner Energir Inc	M12109	Dawn	Parkway	65,000	1-Nov-07	31-Oct-27	N	N
Goreway Station Partnership by its managing partner Goreway Power Station Holdings ULC	M12110	Dawn	Parkway	140,000	1-Nov-07	31-Oct-28	N	N
Vermont Gas Systems, Inc.	M12119	Dawn	Parkway	20,000	1-Nov-07	31-Oct-21	N	N
Greater Toronto Airports Authority	M12120	Dawn	Parkway	7,500	1-Nov-07	31-Oct-21	N	N
St. Lawrence Gas Company, Inc.	M12126	Dawn	Parkway	10,785	1-Nov-08	31-Oct-21	N	Y
Portlands Energy Centre L.P. by its General Partner, Portlands Energy Centre Inc.	M12130	Dawn	Parkway	100,000	13-Jan-09	31-Oct-28	N	N
Energir, L.P. by its General Partner Energir Inc	M12132	Dawn	Parkway	52,343	1-Apr-09	31-Mar-21	N	N
Ag Energy Co-operative Ltd.	M12151	Dawn	Parkway	1,247	1-Nov-08	31-Oct-20	N	N
The Narragansett Electric Company d/b/a National Grid	M12164	Dawn	Parkway	1,081	1-Nov-11	31-Oct-21	N	N

January 2019

Customer Name	Contract Identifier	Receipt Point	Delivery Point	Quantity (GJ)	Start Date	End Date	Negotiated Rate	Affiliate
Connecticut Natural Gas Corporation	M12166	Dawn	Parkway	6,410	1-Nov-11	31-Oct-21	N	N
Ag Energy Co-operative Ltd.	M12167	Dawn	Parkway	1,900	1-Nov-11	31-Oct-21	N	N
Consolidated Edison Company of New York, Inc. and Orange and Rockland Utilities, Inc.	M12171	Dawn	Parkway	21,825	1-Nov-11	31-Oct-21	N	N
Energir, L.P. by its General Partner Energir Inc	M12172	Dawn	Parkway	22,908	1-Apr-10	31-Mar-21	N	N
Energir, L.P. by its General Partner Energir Inc	M12176	Dawn	Parkway	88,728	1-Apr-11	31-Mar-21	N	N
Central Hudson Gas & Electric Corporation (a subsidiary of CH Energy Group, Inc.)	M12182	Dawn	Parkway	5,467	1-Nov-11	31-Oct-21	N	N
York Energy Centre LP	M12184	Dawn	Parkway	76,000	1-Apr-12	31-Oct-22	N	N
Niagara Mohawk Power Corporation d/b/a National Grid	M12186	Dawn	Parkway	55,123	1-Nov-11	31-Oct-21	N	N
Vermont Gas Systems, Inc.	M12190	Dawn	Parkway	500	1-Nov-10	31-Oct-21	N	N
The Brooklyn Union Gas Company d/b/a National Grid NY	M12193	Dawn	Parkway	12,953	1-Nov-10	31-Oct-21	N	N
KeySpan Gas East Corporation d/b/a National Grid	M12194	Dawn	Parkway	17,162	1-Nov-10	31-Oct-20	N	N
Central Hudson Gas & Electric Corporation (a subsidiary of CH Energy Group, Inc.)	M12195	Dawn	Parkway	10,792	1-Nov-10	31-Oct-21	N	N
Boston Gas Company d/b/a National Grid	M12197	Dawn	Parkway	9,282	1-Nov-10	31-Oct-21	N	N
Colonial Gas Company d/b/a National Grid	M12198	Dawn	Parkway	6,475	1-Nov-10	31-Oct-21	N	N
Boston Gas Company d/b/a National Grid	M12199	Dawn	Parkway	2,158	1-Nov-10	31-Oct-21	N	N
Liberty Utilities (EnergyNorth Natural Gas) Corp.	M12200	Dawn	Parkway	4,317	1-Nov-10	31-Oct-22	N	N
Connecticut Natural Gas Corporation	M12201	Dawn	Parkway	18,077	1-Nov-10	31-Oct-21	N	N
The Southern Connecticut Gas Company	M12202	Dawn	Parkway	34,950	1-Nov-10	31-Oct-21	N	N
Yankee Gas Services Company dba Eversource Energy	M12203	Dawn	Parkway	43,116	1-Nov-10	31-Oct-21	N	N
Bay State Gas Company dba Columbia Gas of Massachusetts	M12204	Dawn	Parkway	27,803	1-Nov-10	31-Oct-22	N	N
Connecticut Natural Gas Corporation	M12206	Dawn	Parkway	9,170	1-Nov-10	31-Oct-21	N	N
The Southern Connecticut Gas Company	M12207	Dawn	Parkway	13,970	1-Nov-10	31-Oct-21	N	N
The Brooklyn Union Gas Company d/b/a National Grid NY	M12208	Dawn	Parkway	30,217	1-Nov-10	31-Oct-21	N	N
KeySpan Gas East Corporation d/b/a National Grid	M12209	Dawn	Parkway	22,772	1-Nov-10	31-Oct-21	N	N
Yankee Gas Services Company dba Eversource Energy	M12210	Dawn	Parkway	20,560	1-Nov-10	31-Oct-21	N	N
Yankee Gas Services Company dba Eversource Energy	M12212	Dawn	Parkway	5,380	1-Nov-10	31-Oct-21	N	N
The Southern Connecticut Gas Company	M12213	Dawn	Parkway	9,735	1-Nov-10	31-Oct-21	N	N
Connecticut Natural Gas Corporation	M12214	Dawn	Parkway	6,489	1-Nov-10	31-Oct-21	N	N
Suncor Energy Products Partnership Produits Suncor Energie, S.E.N.C.	M12217	Dawn	Parkway	9,585	1-Nov-11	31-Oct-21	N	N
Energir, L.P. by its General Partner Energir Inc	M12222	Dawn	Parkway	257,784	1-Nov-15	31-Oct-25	N	N
Vermont Gas Systems, Inc.	M12224	Dawn	Parkway	8,100	1-Nov-14	31-Oct-24	N	N
Energir, L.P. by its General Partner Energir Inc	M12232	Dawn	Parkway	39,507	1-Nov-16	31-Oct-31	N	N
Energir, L.P. by its General Partner Energir Inc	M12233	Dawn	Parkway	19,754	1-Nov-16	31-Oct-31	N	N
Energir, L.P. by its General Partner Energir Inc	M12237	Dawn	Parkway	85,680	1-Nov-16	31-Oct-31	N	N
Energir, L.P. by its General Partner Energir Inc	M12244	Dawn	Parkway	36,670	1-Nov-17	31-Oct-32	N	N
TransCanada Energy Ltd.	M12246	Dawn	Parkway	143,775	1-Nov-17	31-Oct-32	N	N
St. Lawrence Gas Company, Inc.	M12249	Dawn	Parkway	10,412	1-Nov-17	31-Oct-32	N	Y
1425445 Ontario Limited o/a Utilities Kingston	M12251	Dawn	Parkway	5,000	1-Nov-17	31-Oct-32	N	N
Northern Utilities, Inc.	M12256	Dawn	Parkway	42,962	1-Nov-17	31-Oct-33	N	N
Portland Natural Gas Transmission System	M12266-AS1	Dawn	Parkway	1,957	1-Nov-18	31-Oct-40	N	N
Enbridge Gas New Brunswick Limited Partnership by its General Partner, Enbridge Gas New Brunswick Inc.	M12270	Dawn	Parkway	2,650	1-Nov-18	31-Oct-40	N	Y
Boston Gas Company d/b/a National Grid	M12273	Dawn	Parkway	22,332	1-Nov-18	31-Oct-40	N	N
The Narragansett Electric Company d/b/a National Grid	M12274	Dawn	Parkway	11,349	1-Nov-18	31-Oct-40	N	N
Heritage Gas Limited	M12276	Dawn	Parkway	3,978	1-Nov-18	31-Oct-40	N	N

January 2019

Customer Name	Contract Identifier	Receipt Point	Delivery Point	Quantity (GJ)	Start Date	End Date	Negotiated Rate	Affiliate
Enbridge Gas New Brunswick Limited Partnership by its General Partner, Enbridge Gas New Brunswick Inc.	M12277	Dawn	Parkway	112	1-Nov-18	31-Oct-40	N	Y
TransCanada PipeLines Limited	M12X004	Dawn	Parkway	50,000	1-Sep-11	31-Aug-21	N	N
TransCanada PipeLines Limited	M12X005	Dawn	Parkway	78,316	1-Sep-11	31-Aug-21	N	N
TransCanada PipeLines Limited	M12X013	Dawn	Parkway	62,695	1-Nov-12	31-Oct-23	N	N
1425445 Ontario Limited o/a Utilities Kingston	M12X015	Dawn	Parkway	5,000	1-Apr-14	31-Mar-24	N	N
Enbridge Gas Inc. (In-Franchise Customers - EGD Zone) *		Dawn	Parkway	2,917,173	1-Jan-19	31-Oct-19	N	Y
In-Franchise Customers - Union South and North Zones		Dawn	Parkway	2,333,248	1-Nov-18	31-Oct-19	N	Y
SUBTOTAL (Dawn to Parkway)				**7,379,255**				
TransCanada PipeLines Limited	M12219	Kirkwall	Parkway	88,497	1-Nov-12	31-Oct-22	N	N
TransCanada PipeLines Limited	M12220	Kirkwall	Parkway	174,752	1-Nov-13	31-Oct-23	N	N
Emera Energy Limited Partnership	M12221	Kirkwall	Parkway	36,751	1-Nov-12	31-Oct-22	N	N
TransCanada PipeLines Limited	M12230	Kirkwall	Parkway	36,301	1-Nov-16	31-Oct-31	N	N
1425445 Ontario Limited o/a Utilities Kingston	M12252	Kirkwall	Parkway	1,000	1-Nov-17	31-Oct-32	N	N
The Corporation of the City of Kitchener	M12253	Kirkwall	Parkway	10,000	1-Nov-17	31-Oct-32	N	N
DTE Energy Trading, Inc.	M12255	Kirkwall	Parkway	73,854	1-Nov-17	31-Oct-31	N	N
SUBTOTAL (Kirkwall to Parkway)				**421,155**				

* - comprised of former contract #'s: M12079B, M12080, M12108, M12125, M12188, M12225, M12234, M12250 & M12X006

** - comprised of former contract #'s: M12079A & M12175

*** - comprised of former contract #: C10009

ENBRIDGE GAS INC.
Answer to Interrogatory from
Federation of Rental-housing Providers of Ontario (FRPO)

Reference: Exhibit B1 / Tab 1 / Schedule 1/ p. 32-33

Preamble: EGI's evidence states: *Enbridge Gas proposes to update the allocation of the PDO and PDCI demand-related costs based on the 2019 Dawn-Parkway design day demands and the allocation of the in-franchise compressor fuel costs based on 2019 forecast volumes.*

Question:

We would like to understand better this PDO and PDCI adjustment.

Is this adjustment premised on the principle that all of the costs of the Dawn-Parkway system including the 2015-2017 expansions are included?

Response

No. Enbridge Gas has updated the allocation factors for PDO and PDCI costs in the current application to reflect the 2019 forecast consistent with the use of 2019 forecast billing units to derive the PDO rates provided at Exhibit F1, Tab 2, Rate Order, Working Papers, Schedule 11, pp. 7-9.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Federation of Rental-housing Providers of Ontario (FRPO)

Reference: Exhibit B1 / Tab 1 / Schedule 1/ p. 32-33

Preamble: EGI's evidence states: *Enbridge Gas proposes to update the allocation of the PDO and PDCI demand-related costs based on the 2019 Dawn-Parkway design day demands and the allocation of the in-franchise compressor fuel costs based on 2019 forecast volumes.*

Question:

Is this precisely the same methodology including assumptions developed for and implemented in the 2014-2018 period?

a) If not, please re-produce Tab F1, Tab 2, Rate Order, Working Papers, Schedule 11 using the original methodology and assumptions.

b) If so, please describe what adjustments are taking place and provide the 2018 and 2019 figures for those respective categories of adjustments.

Response

The methodology used to calculate the proposed 2019 PDO and PDCI costs is the same methodology used to calculate the Board-approved PDO and PDCI costs during the 2014 to 2018 period.

A description of the 2019 PDO and PDCI costs changes is provided in Table 1.

Table 1
Summary of 2019 PDO and PDCI Changes

Line No.	Particulars ($000's)	PDO and PDCI Costs 2018 Approved (1)	2019 Proposed (2)	Change	
		(a)	(b)	(c) = (b-a)	
1	PDO Demand Costs	9,726	10,880	1,154	(3)
2	PDO Fuel Costs	1,705	1,640	(64)	(4)
3	PDCI Demand Costs	10,300	9,930	(370)	(5)
4	PDCI Fuel Costs	2,364	2,272	(92)	(6)
5	Total	24,095	24,723	627	

Notes:

(1) PDO Costs from EB-2017-0087, Rate Order, Working Papers, Schedule 20, p. 1 and updated PDCI costs from EB-2018-0253, Rate Order, Working Papers, Schedule 3, p. 1.

(2) Exhibit F1, Tab 2, Rate Order, Working Papers, Schedule 11, p. 1.

(3) 2019 PDO demand cost change related to the 70 TJ/d of Rate M12 turnback not offset by increased Rate T2 charges and a decrease in the proposed 2019 Rate M12 Dawn-Parkway demand charge.

(4) 2019 PDO fuel cost change related to an update to the October 1, 2018 QRAM.

(5) 2019 PDCI demand cost change related to a decrease in the proposed 2019 Rate M12 Dawn-Parkway demand charge.

(6) 2019 PDCI fuel cost change related to an update to the 2019 Rate M12 Dawn-Parkway fuel ratio and the October 1, 2018 QRAM.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Federation of Rental-housing Providers of Ontario (FRPO)

Reference: Exhibit B1 / Tab 1 / Schedule 1/ p. 42

Preamble: EGI's evidence states: *As of November 1, 2017 the initial Parkway shortfall has been fully eliminated as a result of Dawn to Kirkwall turnback, and therefore Union did not need to take action to manage the shortfall..*

Question:

We would like to understand better how the shortfall was managed in the period after PDO reduction started and November 1, 2017.

Please confirm that Union South experienced a peak day in mid-February 2015.

a) What was the capacity of the Dawn-Parkway system for the winter of 2014/15?
b) For the peak day or day of highest Dawn-Parkway throughput in February:
   i) What was the throughput?
   ii) What was the daily demand at Parkway?
   iii) What was the daily demand at Kirkwall?
   iv) What was the in-franchise demand?
   v) Please explain how any shortfall was managed?

Response

While the heating degree day on February 15, 2015 reached the design heating degree day, the day was not considered a design day as it occurred on a holiday when gas usage is lower than if the weather condition occurred during a weekday.

a) 6842 TJ/d
b) The following are the results from February 15, 2015.
   i) 5376 TJ/d
   ii) 3844 TJ/d
   iii) 976 TJ/d
   iv) 1629 TJ/d
   v) There was a system surplus in Winter 14/15 and therefore no shortfall to manage

ENBRIDGE GAS INC.
Answer to Interrogatory from
Federation of Rental-housing Providers of Ontario (FRPO)

Reference: Exhibit B1 / Tab 1 / Schedule 1/ Appendix A/ page 2

Preamble: EGI's evidence states: *The PGVA will record adjustments related to transactional services activities which are designed to record the impact of direct and avoided costs between the PGVA and the TSDA. These adjustments are required to ensure appropriate allocation of costs and benefits to the underlying transactions and appropriate recording of amounts in the PGVA and TSDA for purposes of deferral account dispositions.*

Question:

We would like to understand better how these transactions are distinguished?

Please provide the policy or guidelines followed by staff to differentiate direct and avoided costs between PGVA and TSDA.

a) Please clarify if this is a new practice or, if it has been in place, for how long.
b) Please provide a few examples of how this policy or guideline is used.
c) Are there any financial employee incentives tied to the level of margin for TSDA for those distinguishing the difference?

Response

a) The practice of recording direct and avoided costs between the PGVA and the TSDA at EGD has been in place for more than 10 years.

b) An example of Direct and Avoided costs would be in relation to fuel costs. If by entering in a Transactional Services deal the Company avoids fuel costs, the deemed fuel cost wold be charged to the PGVA and credited to Transactional Services Revenue.

c) There are no specific employee incentives tied to the level of margin for Transactional Services Revenue.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Federation of Rental-housing Providers of Ontario (FRPO)

Reference: Exhibit B1 / Tab 1 / Schedule 1/ Appendix A/ page 2

Preamble: EGI evidences states: *In addition, the PGVA will record the amounts related to unforecast penalty revenues received from interruptible customers who do not comply with the Company's curtailment requirements, unauthorized overrun gas revenues, the use of electronic bulletin boards, and the unforecast Unabsorbed Demand Charge ("UDC") that arises as a consequence of the Company voluntarily leaving transportation capacity unutilized in order to gain a net benefit for the customer by purchasing lower priced unforecast discretionary delivered supplies.*

Question:

We are interested in understanding better how the un-forecast UDC costs will be tracked with the alternative purchases.

Please clarify EGI's intention regarding tracking these UDC costs. Please include explanation of:

a) The timing of these UDC charges.
b) The timing of corresponding alternative arrangements for the purpose of matching.
c) How corresponding marketing of the unutilized capacity will be tracked.
d) The determination of net benefit of the series of transactions.
e) The allocation of the net benefit.

Response

As per the Board's Procedural Order No. 3, the cost consequences of Gas Supply will be dealt with as part of a future proceeding.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Federation of Rental-housing Providers of Ontario (FRPO)

Reference: Exhibit B1 / Tab 1 / Schedule 1/ Appendix A/ page 24

Preamble: EGI evidence states: *The purpose of the LRAM is to record the amount of distribution margin gained or lost when the Company's DSM programs are less or more successful than budgeted in the fiscal year.*

Question:

We would like to understand better the margin calculation associated with LRAM.

Using the Rate 6 class of customers, please describe from EGD's most recent approved DSM dispersal how margin is calculated ensuring that description is provided on:

a) once the savings are verified, how the lost revenues are tied to costs.
b) detail on how the costs are calculated for both fixed and variable costs of the company.

Response

As noted in the evidence, the purpose of the LRAM is to record the amount of distribution margin gained or lost when the volumes savings associated with the Company's DSM programs are less or more successful than the volumes savings budgeted in the fiscal year. Please note however, that Rates 1 and 6 are not included in the LRAM as these rate classes are covered under the Average Use True-up Variance Account ("AUTVA").

a- b) The distribution margin gained or lost is derived by applying the distribution margin rates to gained or lost volumes, this derives the revenue amount recorded in the LRAM account. The LRAM does not recognize or take into consideration the costs associated with the DSM programs.

The Company has provided comprehensive/detailed explanations of the derivation and application of the volumetric margin unit rates used to calculate both the LRAM and AUTVA amounts in previous proceedings including the 2016 deferral and variance account proceeding (EB-2017-0102, Exhibit I.C. EGDI.FRPO.12, pages 1 to 3) and in the 2017 deferral and variance account proceeding (EB-2018-0131, Exhibit I.C.EGDI.FRPO.9, pages 1 and 2).

ENBRIDGE GAS INC.
Answer to Interrogatory from
Federation of Rental-housing Providers of Ontario (FRPO)

Reference: Exhibit B1 / Tab 1 / Schedule 1/ Appendix B/ page 11

Preamble: EGI evidence states: *To record as a debit in Deferral Account No. 179-131 a receivable from customers and a reduction in cost of gas for the unit rate of optimization revenues refunded to in-franchise customers multiplied by the actual distribution transportation volumes.*

Question:

We are interested in understanding better the allocations to this account.

How does EGI differentiate between releasing unplanned UDC transacted through release and holding the capacity for exchange opportunities?

a) Please provide an example from this last winter to describe the considerations, evaluation and decision-making associated with these costs/opportunities.

Response

As per the Board's Procedural Order No. 3, the cost consequences of Gas Supply will be dealt with as part of a future proceeding.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Federation of Rental-housing Providers of Ontario (FRPO)

Reference: Exhibit B1 / Tab 1 / Schedule 1/ Appendix G/ page 1

Preamble: EGI evidence states: *Committment to post the design day Dawn-Parkway system capacity required for Union North, Union South and Enbridge Gas zones on an aggregated basis online as part of the Index of Transportation Customers.*

Question:

Please provide the source of that commitment.

a) Please provide the location, timing and frequency of the posting.

Response

The source of the commitment was EB-2017-0306/EB-2017-0307, Exhibit C.TCPL.3, part f).

a) As stated in EB-2017-0306/EB-2017-0307, Exhibit C.TCPL.3, part f), the posting will be maintained on the Union Gas website, under the Index of Transportation Customers and would be updated annually to align with the Design Day requirements identified in the annual Gas Supply planning process.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Federation of Rental-housing Providers of Ontario (FRPO)

Reference: Exhibit B1 / Tab 2 / Schedule 1/ page 18-20

Preamble: EGI evidence states: *Given the magnitude of the $95.3 million investment in the Sudbury Replacement project, incremental funding of the project is required. The cumulative revenue requirement of the project from 2018 through 2023 is over $47 million. Union was not able to reprioritize 2018 Capital investment in order to fund this investment using existing rates. The purpose of the capital pass through mechanism was to provide a means for Union to make significant investments under its price cap plan. Given that the timing of the investment in the Sudbury Replacement project occurred in late 2018, Enbridge Gas will be impacted by the first full year revenue requirement in 2019, during which time the Incremental Capital Module will apply.*

Question:

We would like to understand better the decisions around the Sudbury Replacement project.

Please provide Union Gas' approved capital budget and actual expenditures for each year of the 2014-2018 IRM period.

Response

The table below includes the 2013 Board Approved capital budget and the subsequent years of actual spend (2014-18).

	2013 Board Approved	2014 Actual	2015 Actual	2016 Actual	2017 Actual	2018 Actual
Capex	347.7	368.2	476.6	691.3	1034	519.2
Less Capital Pass-Through	80	52.6	154.6	352.6	690.8	81.1
Total	267.7	315.6	322	338.7	343.2	438.1

ENBRIDGE GAS INC.
Answer to Interrogatory from
Federation of Rental-housing Providers of Ontario (FRPO)

Reference: Exhibit B1 / Tab 2 / Schedule 1/ page 18-20

Preamble: EGI evidence states: *Given the magnitude of the $95.3 million investment in the Sudbury Replacement project, incremental funding of the project is required. The cumulative revenue requirement of the project from 2018 through 2023 is over $47 million. Union was not able to reprioritize 2018 Capital investment in order to fund this investment using existing rates. The purpose of the capital pass through mechanism was to provide a means for Union to make significant investments under its price cap plan. Given that the timing of the investment in the Sudbury Replacement project occurred in late 2018, Enbridge Gas will be impacted by the first full year revenue requirement in 2019, during which time the Incremental Capital Module will apply.*

Question:

When was the need for the Sudbury Replacement first identified?

Please provide all internal reports and correspondence that pertain to the need and the timing for replacement.

Response

Enbridge Gas declines to provide the requested information.

The identification of the need for the Sudbury Replacement can be found on pages 3, 4 5 and 6 of the pre filed evidence in the EB-2017-0180 proceeding. The Board approved the Sudbury Replacement project LTC on September 28, 2017.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Federation of Rental-housing Providers of Ontario (FRPO)

Reference: Exhibit C1 / Tab 1 / Schedule 1/ page 45 and Exhibit C1 / Tab 2 / Schedule 1/ page 632, 637, et al. & 703

Preamble: EGI uses the term "intolerable risk". We were unable to find a specific definition for the term in the AMP. We would like to understand better how this term is applied

Question:

Please provide EGI's definition of "intolerable risk".

a) How would EGI measure or qualify an issue into that category?
b) How would an issue move from a "tolerable risk" to an "intolerable risk"?

Response

a) The term "intolerable risk" is defined within the EGD rate zone's Risk Tolerance Framework which is shown in Figure 4.1-7, Exhibit C1, Tab 2, Schedule 1, page.74. When a risk is evaluated in the intolerable (red) region, it is identified as an intolerable risk and has exceeded the acceptable risk limit. Enbridge Gas measures the risk using a risk assessment process which evaluates the risk across the risk dimensions outlined in Table 4.1-2 the Risk Dimensions, Exhibit C1, Tab 2, Schedule 1, page 72 for the EGD rate zone, and Exhibit C1, Tab 3, Schedule 1, page 53 for the Union rate zone.

b) Per Table 4.1-1: Risk and Opportunity, Exhibit C1, Tab 2, Schedule 1, page 71, risk is defined as "A negative effect of uncertainty on the organization's objectives expressed as a combination of the likelihood and consequence of a potential event". If either or both likelihood and consequence have increased, there is potential of moving an issue from a "tolerable risk" to an "intolerable risk".

ENBRIDGE GAS INC.
Answer to Interrogatory from
Federation of Rental-housing Providers of Ontario (FRPO)

Reference: Exhibit C1 / Tab 2 / Schedule 1/ pages 1-94

Preamble: We are interested in understanding better some aspects of the EGD Asset Management plan. In reviewing the document, it is evident that KPMG has performed a maturity assessment (p.59) and EGD followed Deloitte's Value-Based Assessment Management Model. However, in reviewing the evidence, it is unclear how either Consulting Firm recognizes the financial incentives to invest capital for the potential of enhanced return.

Question:

From Enbridge's engagement of KPMG, and potentially Deloitte, please provide information shared by the consulting firms that address the reality of shareholder incentives to invest capital.

a) From those materials, please provide information shared by the consulting firm that address the role of employee incentives in enhancing or balancing the shareholder incentives.

b) Please provide EGI's commentary on steps undertaken to ensure that its organizational leadership balances shareholder incentives with customer value in the area of capital planning and decision-making.

Response

Enbridge Gas is committed to the safe, reliable, cost effective and environmentally responsible provision of natural gas to its customers. At the core of this commitment is the effective stewardship of EGD's assets through governance, policy and practices. EGD will apply leading asset management practises to effectively manage the life cycle of assets. Optimal value will be delivered to customers and stakeholders through a sustainable investment plan that balances cost, risk and performance.[1]

a -b) No material on employee incentives in enhancing or balancing the shareholder incentives was provided. KPMG provided guidance on developing the maturity of the Asset Management practice in relation to ISO 55000 principles. One of the

[1] Exhibit C1, Tab 2, Schedule 1, page 64.

principles is leadership commitment and another is alignment with strategic goals, both of which connect to the interests of our customers. As a public company, our strategic direction is focused on our stakeholder which includes public shareholders.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Federation of Rental-housing Providers of Ontario (FRPO)

Reference: Exhibit C1 / Tab 2 / Schedule 1/ pages 1-94

Preamble: We respect that steel gas mains deteriorate over time. At the same time, replacement must occur in a prioritized fashion over decades.

Question:

Please provide any EGD or Union Gas studies that analyzed the merits (financial and risk-related) of enhanced cathodic protection investments to reduce risk and defer replacement requirements.

Response

No such study has been performed at this time. All protected steel mains are monitored at a minimum annually for adequate cathodic protection levels, those areas where the cathodic protection has fallen below protection criteria are assessed by the Corrosion department and repairs are carried out to return the pipe to protected levels.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Federation of Rental-housing Providers of Ontario (FRPO)

Reference: Exhibit C1, Tab 2, Schedule 1, Page 152

Preamble: EGI evidence states: *The predominant failure mechanism for copper risers at EGD is associated only with internal pipe conditions and is not affected by external conditions or the environment. Analysis determined that turbulent flow will be reached in copper risers at pressure as low as 5 PSIG at 30,000 BTU. The average furnace uses between 70,000 BTU to 100,000 BTU. A typical gas water heater uses between 36,000 BTU to 66,000 BTU. This supports the sampling which showed wall loss on all copper risers, as turbulent flow can be reached at such low pressure from standard home appliances. The localized corrosion failure is illustrated in Figure 5.2-55.*

Question:

We are interested in understanding better the risks associated with the erosion corrosion of the copper risers.

In imperial units (psig), what is the maximum and minimum pressure of the majority of EGD distribution systems?

a) If EGD has multiple pressure ranges for distribution, please provide what term is used to describe the system, what range of pressures and the percentage of each systems of all EGD distribution systems under 100 psig.
b) What percentage of these 280,000 risers would actually be exposed to 5 psig?
c) Does EGD have a study that looks at the failure rates of the copper risers in different pressure systems?
    i) If so, please file the study.
d) Is EGD giving priority to the replacement of those risers exposed to the lowest pressures?

Response

a) All copper risers are operating at pressures less than 100 psig. Approximately 86% of the networks in the EGD rate zone's system operate at pressures under 100 psi.

b) 99.6% would be exposed to 5 psig or greater. Approximately, 1000 units are operating below 5 psig.

c) No, with the exception of the approximately 1000 units, copper risers are operating in the same range of system pressures.

d) No, the risers at the lowest pressures would present the lowest probability of failure with all other conditions being equal.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Federation of Rental-housing Providers of Ontario (FRPO)

Reference: Exhibit C1, Tab 3, Schedule 1, Page 161

Preamble: We would like to understand better the delineation between regulated and non-regulated investment in CNG stations.

Question:

How does Union Gas/EGI differentiate which stations are built inside or outside the regulated utility?

a) Are the regulated stations receiving comparable Federal funding and the non-regulated stations?

    i) If not, why not?

Response

Enbridge Gas does not directly provide CNG retail services. The CNG assets owned by Enbridge Gas are typically rented/provided to customers that use those facilities to refuel fleet vehicles they may use and operate or to provide CNG refueling service to others. The determination as to whether a CNG customer rents the refueling facility from the Company or chooses to own and operate these facilities themselves is determined by the customer.

a) Federal government funding in respect of CNG vehicle refueling facilities is subject to an application process. Any party seeking to avail themselves of this funding is free to apply for it. In some cases the funding has been provided to the utility where it is applied to reduce the capital cost of the utility assets required to connect the CNG refueling facility to the Company's gas distribution system. In other cases the funding has been awarded to the CNG customer and applied to enhance the economics of their CNG refueling initiative.

    i. The direction of the funding between the utility and the retail CNG fuel provider would vary from one situation to another based on the characteristics of each project and the objectives of the federal government agency providing the funds.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Federation of Rental-housing Providers of Ontario (FRPO)

Reference: Exhibit C1, Tab 3, Schedule 1, Page 176

Preamble: *EGI evidence states: Based on the current forecast for in-franchise general service and contract growth in the Panhandle Transmission System market, Union has identified the need to reinforce the Panhandle Transmission System for the 2026 to 2027 winter operating season.*

Question:

We would like to understand better Union Gas'/EGI efforts to consider market based solutions to avoid or defer infrastructure investment.

With increased capability to flow gas on Panhandle Eastern, has Union evaluated the benefit of offering an incentive for firm deliveries at Ojibway?

a) If so, what has been done and what has been learned?
b) If not, why not?

Response

Please see the responses to EB-2016-0186, Exhibit B.FRPO.15 and Exhibit B.FRPO.18 as well as EB-2018-0013, Exhibit A, Tab 8, Schedule 2, Pages 1 to7 for an explanation of why increased firm deliveries at Ojibway cannot efficiently serve the forecast growth.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Federation of Rental-housing Providers of Ontario (FRPO)

Reference: Exhibit E1 / Tab 4 / Schedule 2/ page 5

Preamble: EGI evidence states: *In 2017, EGD introduced a process to track and assess potential measurement errors at TCPL's gate stations, compiling a list of measurement assets at each gate station and identified the flow range of each device.*

Question:

We are interested in understanding better the process that EGI has implemented to assess potential measurement errors at TCPL gate stations.

Please provide a list of EGI station sites that have chromatographs or other instrumentation to measure the heat value of the gas received.

a) Beyond the Victoria Square Station, please identify any concerns that EGI has discerned since implementing this program.

b) What issues has this program addressed and rectified?

c) Has EGI agreed to any improvements in custody transfer between itself and TCPL since the initiation of this program?

d) If EGI has a chromatograph on the Ottawa line from TCPL, please provide the average daily heat value for the period of October 2018 to December 2018.

e) If EGI has a chromatograph at Parkway, please provide the average daily heat value for the period of October 2018 to December 2018.

Response

As per the Board's Procedural Order No. 3, the cost consequences of Gas Supply will be dealt with as part of a future proceeding.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Federation of Rental-housing Providers of Ontario (FRPO)

Reference: Exhibit E1 / Tab 4 / Schedule 9/ page 2-3

Preamble: EGI evidence states: *This project, in-part, underpins elections made by Enbridge in TCPL's 2019 New Capacity Open Season ("NCOS") which includes 75,000 GJ per day of new short-haul capacity from Parkway to the Enbridge CDA.*

Question:

We are interested in understanding better the system demand need for this capacity.

For the 75,000 GJ per day evidenced in this section:

a) Where is this incremental demand needed?

b) In that location, how much has the 2019/20 demand increased over 2017/18?

c) Is there any compensating reduction in capacity to reduce the impact of the cost of the incremental capacity?

   i) If so, please provide the details of the reduction.
   ii) If not, please provide details on the expected utilization of the excess capacity.

Response

As per the Board's Procedural Order No. 3, the cost consequences of Gas Supply will be dealt with as part of a future proceeding.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Federation of Rental-housing Providers of Ontario (FRPO)

Reference: Exhibit E1 / Tab 4 / Schedule 9/ page 3

Preamble: EGI evidence states: *Union Gas and TCPL each have NCOS offerings for transportation services with projected in service dates for each NCOS as early as November 1, 2021. Union Gas is offering M12 services the Dawn-to-Parkway System, while TCPL is offering various firm transportation services on the Mainline System. The NCOS offering from Union Gas was held from August 29, 2018 to November 16, 2018, while the NCOS offering from TCPL was held from October 15, 2018 to November 14, 2018*

Question:

We are interested in understanding the results of the open season in the context of asset utilization in the future.

Please provide the amount of capacity requested in the initial bid respecting that there are levels of additional negotiating and contracting steps to be exercised (i.e., we respect that the ultimate contracted quantity may vary from the initial bid in the contracting process but we are asking for an indication of the amount bid).

Response

The amount of capacity requested in the initial bids is presented in the following table:

2021 Dawn – Parkway (GJ/d)	2021 Kirkwall – Parkway (GJ/d)	2022 Dawn – Parkway (GJ/d)	2022 Kirkwall – Parkway (GJ/d)
165,000	123,441	25,004	30,000

After initial bids were received and during the contract execution process with customers all of the Kirkwall-PKWY bids for both 2021 and 2022 were terminated and 5,333 GJ/d of the 2022 Dawn-PKWY was terminated.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Federation of Rental-housing Providers of Ontario (FRPO)

Reference: Exhibit E1 / Tab 4 / Schedule 9/ page 3

Preamble: EGI evidence states: *Union Gas and TCPL each have NCOS offerings for transportation services with projected in service dates for each NCOS as early as November 1, 2021. Union Gas is offering M12 services the Dawn-to-Parkway System, while TCPL is offering various firm transportation services on the Mainline System. The NCOS offering from Union Gas was held from August 29, 2018 to November 16, 2018, while the NCOS offering from TCPL was held from October 15, 2018 to November 14, 2018*

Question:

With the best information available at this time, please provide the incremental capacity that would come on line in 2021.

a) What, if any, facilities does EGI believe will be needed to meet this level of contracting?

Response

Enbridge Gas is currently planning to construct approximately 10 kilometers of new NPS 48 pipeline between Kirkwall valve site and Hamilton valve site which will provide incremental capacity of approximately 84,000 GJ/day with an expected in-service date of November 1, 2021.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Federation of Rental-housing Providers of Ontario (FRPO)

Reference: Exhibit E1 / Tab 4 / Schedule 9/ page 3

Preamble: EGI evidence states: *Union Gas and TCPL each have NCOS offerings for transportation services with projected in service dates for each NCOS as early as November 1, 2021. Union Gas is offering M12 services the Dawn-to-Parkway System, while TCPL is offering various firm transportation services on the Mainline System. The NCOS offering from Union Gas was held from August 29, 2018 to November 16, 2018, while the NCOS offering from TCPL was held from October 15, 2018 to November 14, 2018*

Question:

Has EGI initiated any process to determine the markets ability to provide firm transport or obligated deliveries that would reduce potential infrastructure expenditures?

a) If yes, please describe.
b) If not, what inhibits EGI from taking this step contemplated in the Settlement Agreement of Union Gas in last Dawn-Parkway expansion build (EB-2015-0200)?

Response

Once Enbridge Gas receives confirmed volumes for incremental Dawn-Parkway demand as a result of an open season, Enbridge Gas will evaluate all alternatives, including additional facilities and market alternatives, when reviewing plans to meet requested incremental demand.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Federation of Rental-housing Providers of Ontario (FRPO)

Reference: Exhibit E1 / Tab 4 / Schedule 9/ page 3

Preamble: EGI's evidence states: *The 2018 to 2020 toll application was filed in December 2017 under hearing order RH-001-2018 and is currently under review by the NEB. In the meantime, the NEB has approved the tolls resulting from the RH-001-2014 Decision on an interim basis while the 2018 to 2020 toll application is under review. The 2019 Gas Costs budget is underpinned by the interim tolls which, compared to TCPL's previous finalized tolls, yield $30-million in annual savings for EGD's transportation contracts that are in place for the 2019 calendar year.*

Question:

We would like to understand better the cost implications for Ontario resulting from the toll resetting process.

Please provide the applicable NEB reference and, ideally the link, for the TCPL 2018-2020 Rates proceeding.

a) Please describe the methodology and the quantities used to determine the $30 million in annual savings for EGD transportation contracts.
   i) Please present the determination in a table.

b) Using the same approach in a), please provide the comparable figure for Union Gas' TCPL transportation contracts.

c) Did the former Enbridge Gas Distribution and Union Gas companies enter into an agreement to set tolls at the applied for levels?
   i) If the applied for tolls were not tolls used to calculate the $30 million in EGD transportation contract savings, please calculate the annual savings expected from the applied for tolls versus those in place in 2017 for:
      (1) EGD transportation contracts
      (2) Union Gas transportation contracts
      (3) Please produce the above determination in a table that provides understanding of the calculation

d) Did the NEB accept and implement the applied for tolls of that agreement or did they determine the agreement did not set tolls in the public interest?

   i) As a result of the NEB decision, please provide the annual savings expected from the approved tolls versus those in place in 2017 for:
      (1) EGD transportation contracts
      (2) Union Gas transportation contracts
      (3) Please produce the above determination in a table that provides understanding of the calculation.

Response

As per the Board's Procedural Order No. 3, the cost consequences of Gas Supply will be dealt with as part of a future proceeding.

ENBRIDGE GAS INC.
Answer to Interrogatory from
London Property Management Association (LPMA)

Reference: Exhibit B1, Tab 1, Schedule 1, Table 4

Question:

a) Please explain why Enbridge is requesting only one deferral account for the incremental capital module related to the Union Gas zones, rather than one deferral account for each of the Union Gas South zone and the Union Gas North zone.

b) Please explain why separate accounts are needed for the EGD zone and the Union Gas zone if separate accounts are not needed for the Union Gas South and North zones.

Response

a) Enbridge Gas has requested a single ICM deferral account for each of the EGD and Union rate zones in conjunction with the MAADs Decision, which specified that the ICM threshold and incremental capital amounts would be calculated individually for both legacy Union Gas and EGD.[1] As a result, separate ICM deferral accounts for each of the EGD and Union rate zones will be utilized to track the variance between actual ICM rate rider revenues billed in each of the EGD and Union rate zones, versus the actual revenue requirement of ICM projects approved for each of the EGD and Union rate zones. To the extent that costs for ICM projects approved for the Union rate zones are to be recovered differently (i.e. based on usage of the asset) between the Union South and Union North, it will be addressed through the development of ICM rate riders for each respective zone, and through the disposition of amounts captured in the ICM deferral account for the Union rate zones.

b) Please see the response at part a) above.

[1] EB-2017-0306/EB-2017-0307 OEB Decision and Order, August 30, 2018, pages 32 to 34.

ENBRIDGE GAS INC.
Answer to Interrogatory from
London Property Management Association (LPMA)

Reference: Exhibit B1, Tab 1, Schedule 1, Tables 6 and 7

Question:

a) Please update Table 6 to reflect actual data for 2018.

b) If applicable, please update Table 7 to reflect any changes resulting from the update of 2018 from forecast to actual.

Response

a) Please refer to the table below. The 2018 amounts shown below are draft. The actual amounts will be filed later this year as part of Enbridge Gas's 2018 Earning Sharing Mechanism and Deferral and Variance Account proceeding.

Table 6

Union's Capital Pass-through Projects
Actual Utility Tax Timing Differences
Union's 2014-2018 IRM
Updated for Exhibit I.LPMA.2 a)

Line No.	Particulars ($000's)	2014	2015	2016	2017	Draft 2018	Total
		(a)	(b)	(c)	(d)	(e)	(f)
1	Parkway West	(2,191)	(4,521)	(5,843)	(4,994)	(4,066)	(21,615)
2	Brantford-Kirkwall/Parkway D	-	(3,668)	(5,462)	(4,744)	(3,938)	(17,811)
3	2016 Dawn-Parkway Expansion	-	(673)	(6,131)	(8,477)	(7,411)	(22,691)
4	Burlington to Oakville	-	-	(1,539)	(2,116)	(1,847)	(5,502)
5	2017 Dawn-Parkway Expansion	-	-	(3,690)	(15,476)	(19,681)	(38,847)
6	Panhandle Reinforcement	-	-	-	(3,385)	(5,498)	(8,883)
7	Total	(2,191)	(8,861)	(22,665)	(39,192)	(42,442)	(115,350)

b) Please refer to the table below.

Table 7

Union's Capital Pass-through Projects
Forecast of Utility Tax Timing Differences
2019-2023 Deferred Rebasing Period
Updated for Exhibit I.LPMA.2 a)

Line No.	Particulars ($000's)	2019	2020	2021	2022	2023	Total
		(a)	(b)	(c)	(d)	(e)	(f)
1	Parkway West	(3,281)	(2,587)	(1,966)	(1,438)	(988)	(10,259)
2	Brantford-Kirkwall/Parkway D	(3,234)	(2,625)	(2,097)	(1,638)	(1,239)	(10,833)
3	2016 Dawn-Parkway Expansion	(6,233)	(5,203)	(4,301)	(3,510)	(2,813)	(22,060)
4	Burlington to Oakville	(1,574)	(1,303)	(1,073)	(877)	(709)	(5,537)
5	2017 Dawn-Parkway Expansion	(16,784)	(13,828)	(10,968)	(8,528)	(6,444)	(56,553)
6	Panhandle Reinforcement	(5,234)	(4,481)	(3,767)	(3,152)	(2,622)	(19,255)
7	Total	(36,339)	(30,027)	(24,172)	(19,143)	(14,816)	(124,497)
8	2019 Utility Tax Timing Difference	(36,415)	(36,415)	(36,415)	(36,415)	(36,415)	(182,075)
9	Variance (line 7 - line 8)	76	6,388	12,243	17,272	21,599	57,578

ENBRIDGE GAS INC.
Answer to Interrogatory from
London Property Management Association (LPMA)

Reference: Exhibit B1, Tab 1, Schedule 1, pages 28-29

Question:

a) Please confirm that the 30,393 GJ/day of surplus capacity noted on page 28 has been sold long-term as of November 1, 2018. If the full amount of the surplus capacity has not been sold, please provide details on the amount sold and the amount currently still available.

b) Please provide the revenue requirement associated with the 30,393 GJ/day that has been built into 2019 rates along with the forecasted revenue associated with this surplus capacity that has been built into 2019 rates.

c) For each of 2020 through 2023, please provide the forecasted revenue requirement associated with the 30,393 GJ/day of surplus capacity, along with the forecasted revenue generated by this surplus capacity.

Response

a) Confirmed, please see Exhibit I.STAFF.11, part (a).

b) There is no specific revenue requirement for the 30,393 GJ/d of incremental Dawn-Parkway demands. Enbridge Gas has built the 2017 Dawn-Parkway Project revenue requirement of $40.916 million into 2019 Rates, of which $46.306 million has been allocated to Rate M12[1]. Please see Exhibit I.STAFF.11, part f).

c) Enbridge Gas does not have a forecast of the project revenue requirement associated with the 30,393 GJ/d. By adjusting the billing units used to derive the Rate M12 demand charges by the incremental demands, the revenue adjustment in rates will be based on the approved Rate M12 Dawn-Parkway demand charge for each year from 2020 to 2023.

[1] The allocation of the capital pass-through projects is provided at Exhibit F1, Tab 2, Rate Order, Working Papers, Schedule 16, page 3.

ENBRIDGE GAS INC.
Answer to Interrogatory from
London Property Management Association (LPMA)

Reference: Exhibit B1, Tab 1, Schedule 1, Table 11

Question:

a) Please provide a table similar to Table 11 that shows the delivery bill impacts for rates 10 and M2 using appropriate volumes.

b) Please confirm that the proposed rate design increases the percent change for small volume users while decreasing the percent change for larger volume users in of the general service rate classes (M1, 01, M2 & 10). If this cannot be confirmed, please explain the different impacts by rate class.

Response

a) Please see Table 1 for the delivery bill impacts for Rate M2 and Rate 10 of the current and proposed cost adjustments.

Table 1

Delivery Bill Impacts for Rate M2 and Rate 10

Monthly Customer Charge Adjustment

Line No.	Particulars ($)	Union South Rate M2		Union North Rate 10	
		(a)	(b)	(c)	(d)
1	Annual Consumption	60,000 m^3	250,000 m^3	60,000 m^3	250,000 m^3
2	Approved Delivery Bill (1)	4,196	14,266	4,868	16,059
3	2019 Rates - Current Approved Rate Design	4,123	13,876	5,086	16,879
4	Difference (line 3 - line 2)	(73)	(390)	218	820
5	Delivery Bill Impact (%) (line 4/line 2)	-1.7%	-2.7%	4.5%	5.1%
6	2019 Rates - Proposed Rate Design (2)	4,100	13,877	5,065	16,883
7	Difference (line 6 - line 2)	(96)	(389)	198	824
8	Delivery Bill Impact (%) (line 7/line 2)	-2.3%	-2.7%	4.1%	5.1%

Notes:

(1) October 2018 QRAM (EB-2018-0253)

(2) Exhibit F1, Tab 2, Rate Order, Working Papers, Schedule 4, column (c).

b) Confirmed for Rate M1 and Rate 01.

Not confirmed for Rate M2 and Rate 10. The current approved cost adjustment for Rate M2 and Rate 10 recovers the customer-related cost variance in proportion to the current approved delivery commodity revenue of the first two delivery blocks only. Enbridge Gas proposes to harmonize the monthly customer charge adjustment for all Union rate zone general service classes as proposed. The proposed rate design for Rate M2 and Rate 10 decreases the unit rate of the first two delivery blocks and increases the unit rate of the remaining delivery blocks of each rate class. The delivery bill impact of the proposal for small volume and large volume users in Rate M2 and Rate 10 is less than 1%, as shown in Table 1.

ENBRIDGE GAS INC.
Answer to Interrogatory from
London Property Management Association (LPMA)

Reference: Exhibit B1, Tab 1, Schedule 1, page 33

Question:

Please provide a reference for where the "2019 approved volumes" noted at lines 20-21 can be found.

Response

The volumes used to pool the Rate M4 and Rate M5 DSM costs are based on Enbridge Gas's 2019 forecast, which are the same volumes used to derive the DSM unit rate. The volumes are provided at Exhibit F1, Tab 2, Rate Order, Working Papers, Schedule 10, page 3, column (b), Line 15 and Line 19 respectively. The evidence should have correctly described the volumes as "2019 forecast volumes".

ENBRIDGE GAS INC.
Answer to Interrogatory from
London Property Management Association (LPMA)

Reference: Exhibit F1, Tab 2, Rate Order Working Papers, Schedule 4

Question:

Please provide the volumes used in calculating the bill impacts for each of the following rate classes in the Union South zone:

a) Small M2 customer;
b) Large M2 customer;
c) Small M4 customer; and
d) Large M4 customer.

Response

Please see Table 1 for the annual volumes used to calculate bill impacts for Rate M2 and Rate M4. Contract demands are also used to calculate bill impacts for Rate M4 and are also provided in Table 1.

Table 1

Parameters for Bill Impacts Calculation

Line No.	Particulars	Annual Volumes (m^3) (a)	Contract Demand (m^3/d) (b)
1	Rate M2 – Small	60,000	N/A
2	Rate M2 – Large	250,000	N/A
3	Rate M4 – Small	875,000	4,800
4	Rate M4 – Large	12,000,000	50,000

ENBRIDGE GAS INC.
Answer to Interrogatory from
London Property Management Association (LPMA)

Reference: Exhibit B1, Tab 1, Schedule 1, pages 26-29

Question:

a) Please expand Table 10 to reflect the revenue requirement for each of the projects shown for each of 2020 through 2023.

b) Please confirm that the EB-2017-0306/EB-2017-0307 Decision and Order referenced in footnote 19 directed Enbridge Gas Inc. to include the rate base and depreciation of the noted projects in the calculation of the eligible incremental capital amount of the Union service territory.

c) Please confirm that the above noted Decision and Order did not direct Enbridge Gas Inc. to adjust rates to reflect the net difference between the 2018 and 2019 revenue requirements associated with capital pass-through projects in the Union service territory. If this cannot be confirmed, please provide a reference to where this direction occurred.

d) Does Enbridge Gas Inc. propose to adjust rates in each of 2020 through 2023 to reflect the net difference between the test year and the previous year revenue requirements associated with the capital pass-through projects in the Union service territory in the same way as it is proposing for 2019 and 2018? If not, why not?

Response

a) Please refer to the Table on the following page.

Table 1
Summary of 2019-2023 Forecast Revenue Requirement of Capital Pass-Through Projects

Line No.	Particulars ($000's)	2019 Forecast(1)	2020 Forecast	2021 Forecast	2022 Forecast	2023 Forecast
		(a)	(b)	(c)	(d)	(e)
1	Parkway West	19,227	19,673	19,971	20,178	20,307
2	Brantford-Kirkwall/Parkway D	14,874	15,142	15,329	15,447	15,506
3	2016 Dawn-Parkway Expansion	25,059	25,609	26,024	26,328	26,537
4	Burlington to Oakville	5,447	5,596	5,707	5,787	5,840
5	2017 Dawn-Parkway Expansion	40,916	43,394	45,153	46,495	47,480
6	Panhandle Reinforcement (2)	11,715	11,139	10,702	10,177	9,576
7	Total (3)	117,238	120,552	122,887	124,411	125,245

Notes:
(1) Exhibit F1, Tab 2, Rate Order, Working Papers, Schedule 16, pp.4-5.
(2) Panhandle Reinforcement project revenue requirement net of incremental project revenue.
(3) Exhibit I.SEC.6, Attachment 1, line 15.

b) Confirmed.

c) Confirmed. Enbridge Gas is proposing to update rates to reflect the 2019 forecast revenue requirement associated with Union's capital pass-through projects as part of this application. By updating the revenue requirement in 2019 rates, Enbridge Gas will reduce the variance between the actual revenue requirement and the revenue requirement included in rates that would otherwise be recorded in the capital pass-through deferral accounts in 2019. Without this proposal, the revenue requirement included in rates would continue to be based on the 2018 forecast approved in the leave to construct application for each project.[1] The update also supports Enbridge Gas's proposal to fix the capital pass-through revenue requirement in rates and discontinue recording differences in the deferral account with the exception of utility tax timing differences. Please see Exhibit I.STAFF.8, part (a).

[1] EB-2017-0087, Exhibit A, Rate Order, Appendix G, pages 1 to 7.

d) No. Enbridge Gas is proposing to fix the capital pass-through revenue requirement in 2019 rates and discontinue recording differences in the deferral account with the exception of utility tax timing differences. Please see Exhibit I.STAFF.8, part (a).

ENBRIDGE GAS INC.
Answer to Interrogatory from
London Property Management Association (LPMA)

Reference: Exhibit B1, Tab 1, Schedule 1, pages 31-33

Question:

a) Given that Enbridge Gas is required to track actual costs and amounts recovered through rates related to the PDO during the deferred rebasing period for review at the time of rebasing, please explain why Enbridge Gas is proposing to adjust the PDO related costs for 2019.

b) The evidence states that the allocation of the PD) costs for 2019 has been updated for the 2019 forecast and that the allocation of in-franchise compressor fuel costs are also based on 2019 forecast volumes. Please explain how the forecast of 2019 volumes has been determined for each rate class.

Response

a) Enbridge Gas is proposing to adjust the PDO related costs to comply with the Settlement Framework for the Reduction of Parkway Delivery Obligation (“PDO Settlement Framework”)[1] and to manage variances in the Parkway Obligation Rate Variance Deferral Account (No. 179-138) (“PORVDA”).

The PDO Settlement Framework provides for updates to the annual PDO costs to reflect the current Rate M12 Dawn to Parkway demand charge and fuel costs based on the October 1 QRAM each year.

The PDO Settlement Framework also provides for updates to the PDCI credit rate and the PDCI costs to reflect the current Rate M12 Dawn to Parkway demand change and fuel costs at 100% load factor. The PDCI credit rate is payable to direct purchase and sales service customers with continued obligated deliveries at Parkway. The PDCI costs included in 2019 Rates is set to equal and offset the forecast of the PDCI rate payable to customers.

[1] Union’s 2014 Rates Decision and Order (EB-2013-0365), June 16, 2014.

The objective of the PDO Settlement Framework is to keep Enbridge Gas (previously Union) whole and by updating for changes in PDO and PDCI costs in proposed 2019 rates, Enbridge Gas remains consistent with that objective.

Enbridge Gas has also updated the PDO and PDCI costs in 2019 rates to reduce the variances that would otherwise be recorded in the PORVDA. The PORVDA is designed to record variances associated with the timing differences between the effective date of the Parkway delivery obligation changes and the inclusion of the cost impacts in approved rates (January 1 of the following year). As part of the MAADs Decision, the OEB approved the continuation of the PORVDA.

The requirement to track actual costs and amounts recovered in rates is in addition to the PDO Settlement Framework. The MAADs Decision requires Enbridge Gas to track actual costs and amounts recovered through rates related to the PDO during the deferred rebasing period to ensure ratepayers are not paying twice for the required capacity. The annual update in rates for the PDO related costs reflects changes to the Dawn-Parkway capacity already recovered in rates.

b) The 2019 forecast used to allocate 2019 compressor fuel volumes was developed using methodologies consistent with those used by legacy Union in its last rebasing proceeding (EB-2011-0210).

The 2019 volume forecast by rate class was derived based on customer type. The 2019 general service volume forecast was determined through multiple regression analyses which consider drivers such as the total number of customers, average consumption, approved weather methodologies and conservation programs.
The 2019 contract rate volume forecast was determined through review of customer’s historical consumption, consultation with customers and knowledge of customer specific plans.

ENBRIDGE GAS INC.
Answer to Interrogatory from
London Property Management Association (LPMA)

Reference: Exhibit B1, Tab 1, Schedule 1, pages 34-39

Question:

Are any of the changes proposed on these pages necessary rate schedule changes? If yes, please explain fully the need and the impact if the changes are not made until rebasing.

Response

Yes, the rate schedule changes are necessary. While the proposed changes to the rate schedules are administrative, they enable Enbridge Gas to maintain accurate rate schedules and general terms and conditions ("GT&C") based on current service offerings and business requirements.

Specifically, the proposed change to the system expansion surcharge is required for accuracy. While the service is not expiring prior to rebasing, the rate schedule requires an update to correct the contract expiry date for the community expansion project areas of Delaware Nation of Moraviantown First Nation and Prince Township.

Enbridge Gas has also proposed to remove a number of services that are no longer in use, including the Union South Rate U2, Union South supplemental services, and the Union South multiple delivery points service option. By requesting elimination of these services, the rate schedules will reflect Enbridge Gas's current service offerings and will eliminate the need for Enbridge Gas to maintain internal processes and system updates for services and rate classes that are no longer relevant. Union Gas made similar changes to services during its previous IRM term, such as the elimination of the Union North general service unbundled storage Rate S1 rate schedule, which was removed as part of the 2017 Rates application (EB-2016-0245).

Similarly, Enbridge Gas also proposed administrative changes to provide consistency and accuracy for the Rate C1 pricing of the Dawn yard interruptible transportation, which is currently provided on Enbridge Gas's Hub Pricing Schedule 2, and the Rate M13 GT&C.

ENBRIDGE GAS INC.
Answer to Interrogatory from
London Property Management Association (LPMA)

Reference: Exhibit B1, Tab 2, Schedule 1

Question:

a) Please updates Tables 1 and 2 to reflect actual data for 2018.

b) Does Table 2 include in-service capital additions related to the capital pass-though projects listed in Table 10 of Exhibit B1, Tab 1, Schedule 1?

c) If yes, please provide a breakout of the in-service capital additions associated with these projects in Table 2.

d) If no, please provide the in-service capital additions related to the capital pass-through projects listed in Table 10 of Exhibit B1, Tab 1, Schedule for the period beginning 2014 and ending in the last year in which there was new in-service capital additions associated with the projects.

Response

a) 2018 actuals for the EGD rate zone are reflected in in Table 1 - column (e) below. 2018 actuals for the Union rate zones are reflected in in Table 2 - column (e).

Table 1

Capital Expenditures by category (2014-2023) – EGD Rate Zone ($ Millions)

Line No.	Category	(a) 2014 Actual	(b) 2015 Actual	(c) 2016 Actual	(d) 2017 Actual	(e) 2018 Actual
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**

[1] System Access capital presented here does not reflect Community Expansion.

Table 2

Capital Expenditures by category (2014-2023) – Union Rate Zones ($ Millions)

Line No.	Category	(a) 2014 Actual	(b) 2015 Actual	(c) 2016 Actual	(d) 2017 Actual	(e) 2018 Actual
1	General Plant	56.5	51.4	44.8	42.8	48
2	System Access[1]	83.9	107.8	105.6	96.2	73.2
3	System Renewal	83.8	73	76.3	87.6	114.9
4	System Service	190.4	391.5	734.3	412.2	196.9
4A	Parkway West[2]	99.3	68.2	16.4	1.4	1.1
4B	Brantford-Kirkwall/Parkway D [2]	39.8	138.1	7.8	1.6	0.0
4C	2016 Dawn-Parkway Expansion[2]	14.2	91.5	222.5	17.2	2.3
4D	Burlington to Oakville[2]	1.2	3.5	74.0	2.7	1.5
4E	2017 Dawn-Parkway Expansion[2]	0.1	51.5	363.0	159.7	39.5
4F	Panhandle Reinforcement[2]	0.0	0.0	7.1	182.4	36.6
5	Total Overhead	68.2	71.5	77.2	78.6	80.1
6	**Total - Union Rate Zones**	**482.9**	**695.2**	**1,038.20**	**717.5**	**513.1**

[1] System Access capital presented here does not reflect Community Expansion.
[2] Breakdown of capital pass-through items included in System Service total (line 4).

b) Yes, Table 2 includes the in-service capital additions related to capital pass-through.

c) Please see the response to part a) for the updates to Table 2 including the breakdown of capital pass-through projects listed in Table 10 of Exhibit B1, Tab 1, Schedule 1.

ENBRIDGE GAS INC.
Answer to Interrogatory from
London Property Management Association (LPMA)

Reference: Exhibit B1, Tab 2, Schedule 1

Question:

Please provide a Union column in Table 3 that reflects a price cap index of 1.07% in place of the 0.72% used.

Response

Please see Table 3 below expanded to include an additional column that reflects the price cap index of 1.07% for Union for the entire period since 2013.

Table 3

ICM Threshold Capital Expenditure Calculation by Rate Zone

Line No.	Particulars ($ millions)	EGD	Union	Union at 1.07% PCI
		(a)	(b)	
1	Year	2019	2019	2019
2	Base Year	2018	2013	2013
3	Number of Years since rebasing (n)	1	6	6
4	Price Cap Index (PCI) (%)	1.07%	0.72%	1.07%
5	Growth Factor (g) (%)	1.04%	1.19%	1.19%
6	Dead Band (%)	10%	10%	10%
7	Rate Base (RB)	6,246	5,331	5,331
8	Depreciation (d)	305	239	239
9	Threshold Value (%)	153%	157%	167%
10	Threshold Value	468.5	375.2	398.5

ENBRIDGE GAS INC.
Answer to Interrogatory from
London Property Management Association (LPMA)

Reference: Exhibit B1, Tab 2, Schedule 1

Question:

Please provide a breakdown of the Union figures shown in Table 4 for each of 2014 through 2019 into the components of the price cap index, being the inflation rate used and the implied productivity factor offset.

Response

Union's annualized PCI- simple average since 2013 is provided in the table below:

Price Cap Index for Union Rate Zone

n	Yr	Inflation: GDP IPI FDD (1)	Productivity /Stretch (2)	PCI (3) = (1) +(2)	Annualized PCI - simple average since 2013
0	2013				
1	2014	1.27%	-0.76%	0.51%	0.51%
2	2015	1.66%	-1.00%	0.66%	0.59%
3	2016	1.77%	-1.06%	0.71%	0.63%
4	2017	1.74%	-1.05%	0.70%	0.64%
5	2018	1.65%	-0.99%	0.66%	0.65%
6	2019	1.37%	-0.30%	1.07%	0.72%

ENBRIDGE GAS INC.
Answer to Interrogatory from
London Property Management Association (LPMA)

Reference: Exhibit B1, Tab 2, Schedule 1, page 15 & Exhibit F1, Tab 2, Rate Order Working Papers, Schedule 16

Question:

a) Please provide the specific reference from the EB-2017-0306/EB-2017-0307 Decision and Order that directed Enbridge Gas to calculate the ICM threshold using the 2013 Board-approved rate base and depreciation plus the 2019 forecast amount of rate base and depreciation associated with the projects that were eligible for capital pass-through treatment and included in Union's base rates during Union's 2014-2018 IRM term.

b) The 2019 rate base and depreciation figures used in the ICM calculation, as shown in Exhibit F1, Tab 1, Schedule 16, pages 4-5 in the Rate Order Working Papers uses approved 2018 figures and 2019 forecasts. Please update this schedule using actual 2018 figures and any resulting changes to the 2019 forecast. Please also provide a revised Table 6 and 7 from Exhibit B1, Tab 2, Schedule 1 that reflects these updated figures.

Response

a) The MAADs Decision directed Enbridge Gas to add the rate base and depreciation associated with projects that were found eligible for capital pass-through treatment during Union's 2014-2018 IRM term to the 2013 rate base and depreciation for purposes of determining the eligible incremental capital amount for Union Gas' service territory. The MAADs Decision did not direct the amount of capital pass-through rate base and depreciation to include.

   Enbridge Gas updated 2019 rates to reflect the 2019 forecast revenue requirement of the capital pass-through projects and included the 2019 forecast rate base and depreciation of the capital pass-through in the ICM threshold calculation. Since the purpose of the ICM materiality threshold is to determine the amount of capital spend that can be supported through current rates, the 2019 rate base and depreciation are used, and is consistent with the proposal to adjust 2019 rates for the 2019 revenue requirement. Please see Exhibit I.STAFF.8, part a).

b) Please see Attachment 1 which provides Exhibit F1, Tab 2, Rate Order, Working Papers, Schedule 16, pages 4 and 5 updated to reflect draft 2018 actual costs and the most recent 2019 forecast revenue requirement for each capital pass-through project.

   The resulting changes to Table 6 and Table 7 from Exhibit B1, Tab 2, Schedule 1 are provided below.

Table 6
ICM Threshold Rate Base and Depreciation Expense by Rate Zone
Updated for Exhibit I.LPMA.13 b)

Line No.	Particulars ($ millions)	Rate Base	Depreciation
		(a)	(b)
	EGD		
1	2013 Board-Approved	6,246	305
	Union		
2	2013 Board-Approved	3,734	196
3	2019 Capital Pass-Through Amounts	1,588	43
4	Total	5,322	239

Table 7
Maximum Eligible Incremental Capital by Rate Zone
Updated for Exhibit I.LPMA.13 b)

Line No.	Particulars ($ millions)	EGD	Union
		(a)	(b)
1	2019 In-Service Capital Forecast	481.7	518.5
2	Less: Materiality Threshold Value	468.5	374.9
3	Maximum Eligible Incremental Capital	13.1	143.6

UNION RATE ZONES

Summary of 2018 Draft Actuals and 2019 Updated Forecast for Capital Pass-Through Projects Revenue Requirement

Line No.	Particulars ($000's)	Parkway Projects: Parkway West 2018 Draft Actuals (a)	2019 Updated Forecast (b)	Change (c) = (b-a)	Brantford to Kirkwall/Parkway D 2018 Draft Actuals (d)	2019 Updated Forecast (e)	Change (f) = (e-d)	2016 Dawn-Parkway Expansion Project 2018 Draft Actuals (g)	2019 Updated Forecast (h)	Change (i) = (h-g)
	Rate Base Investment									
1	Capital Expenditures	1,092	1,454	362	-	-	-	2,464	-	(2,464)
2	Average Investment	213,974	209,671	(4,303)	182,727	177,731	(4,995)	329,689	323,231	(6,458)
	Revenue Requirement Calculation:									
	Operating Expenses:									
3	Operating and Maintenance Expenses	1,320	1,373	53	621	621	-	951	894	(57)
4	Depreciation Expense (1)	5,479	5,509	29	4,995	4,995	-	8,255	8,229	(26)
5	Property Taxes	572	584	11	939	939	-	1,096	1,100	4
6	Total Operating Expenses (line 3 + line 4 + line 5)	7,372	7,465	93	6,555	6,556	-	10,302	10,223	(79)
	Required Return:									
7	Interest Expense	5,231	5,126	(105)	4,467	4,345	(122)	7,090	6,951	(139)
8	Equity Return	6,879	6,740	(138)	5,874	5,714	(161)	10,599	10,391	(208)
9	Total Required Return (line 7 + line 8) (2)	12,110	11,867	(244)	10,342	10,059	(283)	17,688	17,342	(346)
	Income Taxes:									
10	Income Taxes - Equity Return (3)	2,480	2,430	(50)	2,118	2,060	(58)	3,821	3,747	(75)
11	Income Taxes - Utility Timing Differences (4)	(4,066)	(3,281)	786	(3,938)	(3,234)	704	(7,411)	(6,233)	1,178
12	Total Income Taxes (line 10 + line 11)	(1,586)	(850)	736	(1,820)	(1,174)	646	(3,590)	(2,486)	1,104
13	Total Revenue Requirement (line 6 + line 9 + line 12)	17,896	18,482	586	15,077	15,441	363	24,401	25,079	678
14	Incremental Project Revenue Adjustment (5)	-	-	-	-	-	-	-	-	-
15	Capital Pass-through Adjustments (line 13 - line 14)	17,896	18,482	586	15,077	15,441	363	24,401	25,079	678

Notes:

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

(2) The required return assumes a capital structure of 36% common equity at the 2013 Board-approved return of 8.93% and 64% long-term debt. The assumed long-term debt for rates for 2019 are 3.82% for Parkway West and Parkway Growth projects, 3.36% for 2016 Dawn-Parkway Expansion and Burlington to Oakville projects, and 3.29% for 2017 Dawn-Parkway Expansion and Panhandle Reinforcement projects.

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

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

(5) Incremental project revenue reflected as an increase to Rate M12 and Rate C1 billing units used to set rates during the 2014-2018 IRM term except for 30,393 GJ/d of capacity related to the 2017 Dawn-Parkway Project for 2018 and the incremental revenue of the Panhandle Reinforcement Project. Incremental project revenue in 2018 of the 2017 Dawn-Parkway project includes proportional short-term sales for January to October and entire capacity sold long-term M12 Dawn-Parkway for November and December. Incremental project revenue of the Panhandle Reinforcement Project treated as a reduction to the capital pass-through adjustment amount and includes incremental transmission and distribution margin.

UNION RATE ZONES
Summary of 2018 Draft Actuals and 2019 Updated Forecast for Capital Pass-Through Projects Revenue Requirement

Line No.	Particulars ($000's)	Burlington to Oakville Project 2018 Draft Actuals (j)	2019 Updated Forecast (k)	Change (l) = (k-j)	2017 Dawn-Parkway Expansion Project 2018 Draft Actuals (m)	2019 Updated Forecast (n)	Change (o) = (n-m)	Panhandle Reinforcement Project 2018 Draft Actuals (p)	2019 Updated Forecast (q)	Change (r) = (q-p)	Total 2018 Draft Actuals (s)	2019 Updated Forecast (t)	Change (u) = (t-s)
	Rate Base Investment												
1	Capital Expenditures	1,455	-	(1,455)	32,959	15,244	(17,715)	36,454	6,735	(29,719)	74,424	23,433	(50,991)
2	Average Investment	79,289	78,224	(1,064)	569,940	578,948	9,008	203,412	220,477	17,065	1,579,030	1,588,283	9,253
	Revenue Requirement Calculation:												
	Operating Expenses:												
3	Operating and Maintenance Expenses	-	16	16	2,035	2,076	41	-	16	16	4,927	4,995	68
4	Depreciation Expense (1)	1,720	1,737	17	16,035	17,236	1,201	4,473	4,925	452	40,958	42,631	1,673
5	Property Taxes	122	125	3	1,075	1,075	-	1,776	1,848	72	5,580	5,670	90
6	Total Operating Expenses (line 3 + line 4 + line 5)	1,842	1,878	36	19,145	20,386	1,242	6,249	6,788	539	51,465	53,296	1,831
	Required Return:												
7	Interest Expense	1,705	1,682	(23)	12,001	12,190	190	4,283	4,642	359	34,777	34,937	160
8	Equity Return	2,549	2,515	(34)	18,322	18,612	290	6,539	7,088	549	50,763	51,060	297
9	Total Required Return (line 7 + line 8) (2)	4,254	4,197	(57)	30,323	30,802	479	10,822	11,730	908	85,540	85,997	457
	Income Taxes:												
10	Income Taxes - Equity Return (3)	919	907	(12)	6,606	6,710	104	2,358	2,556	198	18,302	18,409	106
11	Income Taxes - Utility Timing Differences (4)	(1,847)	(1,574)	274	(19,681)	(16,784)	2,897	(5,498)	(5,234)	264	(42,442)	(36,339)	6,103
12	Total Income Taxes (line 10 + line 11)	(928)	(667)	261	(13,075)	(10,075)	3,000	(3,140)	(2,678)	462	(24,139)	(17,930)	6,209
13	Total Revenue Requirement (line 6 + line 9 + line 12)	5,168	5,408	240	36,393	41,114	4,721	13,931	15,840	1,909	112,865	121,363	8,498
14	Incremental Project Revenue Adjustment (5)	-	-	-	917	-	(917)	3,607	4,568	961	4,525	4,568	44
15	Capital Pass-through Adjustments (line 13 - line 14)	5,168	5,408	240	35,475	41,114	5,639	10,324	11,272	948	108,341	116,795	8,454

Notes:
(1) Depreciation expense at 2013 Board-approved depreciation rates.
(2) The required return assumes a capital structure of 36% common equity at the 2013 Board-approved return of 8.93% and 64% long-term debt. The assumed long-term debt for rates for 2019 are 3.82% for Parkway West and Parkway Growth projects, 3.36% for 2016 Dawn-Parkway Expansion and Burlington to Oakville projects, and 3.29% for 2017 Dawn-Parkway Expansion and Panhandle Reinforcement projects.
(3) Taxes related to the equity component of the return at a tax rate of 26.5%.
(4) Taxes related to the utility timing differences are negative as the capital cost allowance deduction in arriving at taxable income exceeds the provision of book depreciation in the year.
(5) Incremental project revenue reflected as an increase to Rate M12 and Rate C1 billing units used to set rates during the 2014-2018 IRM term except for 30,393 GJ/d of capacity related to the 2017 Dawn-Parkway Project for 2018 and the incremental revenue of the Panhandle Reinforcement Project. Incremental project revenue in 2018 of the 2017 Dawn-Parkway project includes proportional short-term sales for January to October and entire capacity sold long-term M12 Dawn-Parkway for November and December. Incremental project revenue of the Panhandle Reinforcement Project treated as a reduction to the capital pass-through adjustment amount and includes incremental transmission and distribution margin.

ENBRIDGE GAS INC.
Answer to Interrogatory from
London Property Management Association (LPMA)

Reference: Exhibit B1, Tab 2, Schedule 1, page 19

Question:

If the Sudbury Replacement project had been brought forward under the 2014-2018 capital pass-through mechanism, please provide the following:

a) the proposed rate base and depreciation expense for 2018, reflecting the October 2018 in-service date; and

b) the forecasted rate base and depreciation expense for 2019.

Response

a) 2018 Rate Base (000's) = $17,769
2018 Depreciation (000's) = $1,362

b) 2019 Rate Base (000's) = $89,504
2019 Depreciation (000's) = $2,809

ENBRIDGE GAS INC.
Answer to Interrogatory from
School Energy Coalition (SEC)

Reference: Ex. A, Tab 3, Sched. 1, p. 4, and Ex. B1, Tab 1, Sched. 1, p. 31

Question:

Please provide a table showing distribution bill impacts for a non-residential customer (such as a school) with 40,000 m3 annual consumption in each of rates Union 01 and M1, and EGD 6. If an expansion of Table 11 would accomplish that that is acceptable. Please provide all supporting calculations, in Excel format.

Response

Please see Table 1. The supporting calculation has been attached and filed in excel format as Exhibit I.SEC.1, Attachment 1.

Table 1
Delivery Bill Impacts for Rate 01, Rate M1 and Rate 6

Line No.	Particulars ($)	Union South Rate M1	Union North Rate 01	EGD Rate 6
		(a)	(b)	(c)
1	Annual Consumption	40,000 m^3	40,000 m^3	40,000 m^3
2	Approved Delivery Bill (1)	2,222	3,570	2,717
3	2019 Rates - Proposed	2,250	3,635	2,744
4	Difference (line 3 - line 2)	28	65	28
5	Delivery Bill Impact (%) (line 4 / line 2)	1.3%	1.8%	1.0%

Notes:
(1) October 2018 QRAM (EB-2018-0253).

ENBRIDGE GAS INC.
Table 1
Delivery Bill Impacts for Rate 01, Rate M1 and Rate 6

Line No.	Particulars ($)	Union South Rate M1	Union North Rate 01	EGD Rate 6
		(a)	(b)	(c)
1	Annual Consumption	40,000 m^3	40,000 m^3	40,000 m^3
2	Approved Delivery Bill (1)	2,222	3,570	2,717
3	2019 Rates - Proposed	2,250	3,635	2,744
4	Difference (line 3 - line 2)	28	65	28
5	Delivery Bill Impact (%) (line 4 / line 2)	1.3%	1.8%	1.0%

Notes:
(1) October 2018 QRAM (EB-2018-0253).

ENBRIDGE GAS INC.

Union Rate Zone General Service Rate 01 and Rate M1 Delivery Bill Impacts

Line No.	Particulars	Billing Units	Oct-18 QRAM (1) (cents / m³)	Large Customer Billing Units (m^3)	October QRAM ($)	Proposed Rates (2) (cents / m³)	Large Customer Billing Units (m^3)	2019 Rates Proposed ($)
	Rate 01 General Service							
1	Monthly Charge	bills	$21.00	12	$252	$21.00	12	$252
	Monthly Delivery Charge							
2	First 100 m³	10³m³	9.3755	1,200	113	10.0484	1,200	121
3	Next 200 m³	10³m³	9.1356	2,400	219	9.2549	2,400	222
4	Next 200 m³	10³m³	8.7563	2,400	210	8.8872	2,400	213
5	Next 500 m³	10³m³	8.4081	5,400	454	8.5496	5,400	462
6	Over 1,000 m³	10³m³	8.1204	28,600	2,322	8.2708	28,600	2,365
7	Delivery Commodity charge			40,000	3,318		40,000	3,383
8	Total			40,000	3,570		40,000	3,635
	Rate M1 General Service							
9	Monthly Charge	bills	$21.00	12	$252	$21.00	12	$252
	Monthly Delivery Charge							
10	First 100 m³	10³m³	5.0777	1,200	61	5.9775	1,200	72
11	Next 150 m³	10³m³	4.8140	1,800	87	4.8283	1,800	87
12	All over 250 m³	10³m³	4.1326	37,000	1,529	4.1436	37,000	1,533
13	Delivery Commodity charge			40,000	1,677		40,000	1,692
14	Storage		0.7331	40,000	293.24	0.7653	40,000	306
15	Total			40,000	2,222		40,000	2,250

Notes:
(1) October 2018 QRAM (EB-2018-0253).
(2) EB-2018-0305, Exhibit F1, Tab 2, Rate Order, Appendix A.

ENBRIDGE GAS INC.

EGD Rate Zone General Service Rate 6 Delivery Bill Impacts

Line No.		Billing Units	Oct-18 QRAM (1) (cents / m³)	Commercial Customer Billing Units (m³)	October QRAM ($)	Proposed Rates (2) (cents / m³)	Commercial Customer Billing Units (m³)	2019 Rates Proposed ($)
	Rate 6 General Service							
1	Monthly Charge	bills	$70.00	12	$840	$70.00	12	$840
	Monthly Delivery Charge							
2	First 500 m³	10³m³	7.2824	6,000	$437	7.3356	6,000	$440
3	Next 1050 m³	10³m³	5.1670	12,600	$651	5.2333	12,600	$659
4	Next 4500 m³	10³m³	3.6857	21,400	$789	3.7612	21,400	$805
5	Next 7000 m³	10³m³	2.7340	-	$0	2.8154	-	$0
6	Next 15250 m³	10³m³	2.3111	-	$0	2.3951	-	$0
7	Over 28300 m³	10³m³	2.2049	-	$0	2.2895	-	$0
8	Delivery Commodity charge			40,000	$1,877		40,000	$1,904
9	Total Delivery Charge			40,000	$2,717		40,000	$2,744

Notes:

(1) EB-2018-0305, Exhibit F1, Tab1, Schedule 4, Page 2, Col C minus Col E.

(2) EB-2018-0305, Exhibit F1, Tab1, Schedule 6, Page 1, Col D.

ENBRIDGE GAS INC.
Answer to Interrogatory from
School Energy Coalition (SEC)

Reference: A/3/1, p. 6

Question:

Please advise which school boards, if any, were included in the strategic account customers with which Union sales representatives met to gather feedback. Please provide the dates of those meetings.

Response

No, school boards were not included with the strategic account grouping. School boards would be included in the “not-for-profit or community institution” category of business respondents.

Please see Exhibit D1, Tab 2, Schedule 1, page 212 for the Firmographic Profile of Business Respondents in Union’s Customer Engagement telephone survey.

ENBRIDGE GAS INC.
Answer to Interrogatory from
School Energy Coalition (SEC)

Reference: B1/1/1, p. 2

Question:

a. Confirm that the proposed increase in revenue for EGD Rate Zone is 1.987%.

b. Confirm that the proposed increase in revenue for Union Rate Zones is 2.178%.

c. Adjust those two percentages by changes in billing determinants and heat content, and any other appropriate adjustments, to obtain the weighted average rate increase for each of the EGD Rate Zone and the Union Rate Zones, and provide all supporting calculations, in Excel format.

Response

a) Not confirmed. The increase in revenue as the basis for rate making provided at Exhibit B1, Table 1, results in an increase of 1.987% for the EGD rate zone and 2.178% for the Union rate zone. However, the increase in revenue at Table 1 does not factor in revenue changes associated with changing billing determinants, therefore actual utility revenue will be different.

b) Please see part a).

c) For purposes of this response, Enbridge Gas has estimated an average volumetric 2018 and 2019 delivery rate for in-franchise customers in the EGD and Union rate zones, assuming the proposed revenues are recovered on a volumetric basis only. Note that the average rate does not represent proposed delivery rates for any particular rate class, as the estimated average unit rate does not reflect rate class specific characteristics.

The supporting calculation has been filed in excel format as Exhibit I.SEC.3, Attachment 1.

ENBRIDGE GAS INC.

Estimated 2019 Average Delivery Unit Rates for the EGD and Union Rate Zones

Line No.	Particulars	EGD Rate Zone Revenue (1) ($000's) (a)	EGD Rate Zone Volumes (2) (m^3) (b)	EGD Rate Zone Unit Rate (cents/m^3) (c) = (a/b x 100)	Union Rate Zones Revenue (3) ($000's) (d)	Union Rate Zones Volumes (4) (m^3) (e)	Union Rate Zones Unit Rate (cents/m^3) (f) = (d/e x 100)
1	2018 Approved	1,212,414	11,487,411	10.5543	808,508	13,994,969	5.7771
2	2019 Proposed	1,236,509	11,668,048	10.5974	841,671	14,269,107	5.8986
3	Difference (line 2 - line 1)	24,095		0.0431	33,163		0.1214
4	Difference (%) (line 3 / line 1)	1.987%		0.408%	4.102%		2.102%

Notes:

(1) EB-2018-0305, Exhibit B1, Tab 1, Schedule 1, Table 1.

(2) Exhibit F1, Tab 1, Rate Order, Working Papers, Schedule 5. Estimated average unit rate based on proposed 2019 volumes used to set base delivery rates.

(3) EB-2018-0305, Exhibit B1, Tab 1, Schedule 1, Table 1, proposed revenue change of $27.448 million adjusted to remove ($5.715 million) for ex-franchise, Union North storage and transportation and gas supply administration, as per Exhibit F1, Tab 2, Rate Order, Working Papers, Schedule 2.

(4) Exhibit F1, Tab 2, Rate Order, Working Papers, Schedule 5.

ENBRIDGE GAS INC.
Answer to Interrogatory from
School Energy Coalition (SEC)

Reference: B1/1/1, p. 13

Question:

Please confirm that the Applicant is not aware of any events or circumstances that would qualify for positive or negative Z factor adjustment to 2019 rates. Please provide a list of all events or circumstances that meet three of the four Z factor criteria described by the Board in EB-2017-0306/7, Decision with Reasons, p. 37, and explain why each does not meet the fourth criterion.

Response

Confirmed. Enbridge Gas is not proposing a Z factor for 2019 rates. If the applicant determines that a Z factor adjustment is required, it will file an application to that effect as part of its rates application and conform to the Z factor criteria as established by the Board in the MAADs Decision.

ENBRIDGE GAS INC.
Answer to Interrogatory from
School Energy Coalition (SEC)

Reference: B1/1/1, p. 19

Question:

With respect to the proposal to use the capital pass-through account to adjust for tax timing differences:

a. Please provide the reference in the EB-2017-0306/7 Decision with Reasons in which the Board authorized a base rate adjustment or alteration of rate calculations to reflect tax timing differences.

b. Please explain why the impact of tax timing differences is not just one of the puts and takes that the Applicant accepted in seeking a deferred rebasing.

c. Please provide detailed continuity and CCA schedules for each of the six listed projects from at least 2014 to 2023 so that the details of the timing differences for each project can be identified.

Response

a) Please see Exhibit I.STAFF.8, part a).

b) Please see Exhibit I.STAFF.8, part a).

c) Please see Attachment 1.

Utility Tax Timing Differences and CCA Continuity
Parkway West
2014 to 2023

Line No.	Particulars ($000's)	Actual 2014 (a)	Actual 2015 (b)	Actual 2016 (c)	Actual 2017 (d)	Forecast 2018 (e)	Forecast 2019 (f)	Forecast 2020 (g)	Forecast 2021 (h)	Forecast 2022 (i)	Forecast 2023 (j)	Total (k)
1	Depreciation	577	3,071	5,185	5,415	5,467	5,508	5,532	5,532	5,532	5,532	47,351
2	CCA	(2,625)	(13,719)	(21,393)	(19,268)	(16,754)	(14,605)	(12,707)	(10,984)	(9,520)	(8,274)	(129,850)
3	IDC & Other	(4,028)	(1,891)	2	-	-	-	-	-	-	-	(5,917)
4	Net Timing Differences	(6,076)	(12,539)	(16,206)	(13,853)	(11,288)	(9,097)	(7,175)	(5,452)	(3,988)	(2,741)	(88,415)
5	Utility Tax Timing Difference	(1,610)	(3,323)	(4,295)	(3,671)	(2,991)	(2,411)	(1,901)	(1,445)	(1,057)	(726)	(23,430)
6	Grossed Up Utility Tax Timing Difference	(2,191)	(4,521)	(5,843)	(4,994)	(4,070)	(3,280)	(2,587)	(1,966)	(1,438)	(988)	(31,878)
	CCA Continuity											
	CCA Class 1 - Rate 6%											
7	Opening UCC	-	17,324	39,127	43,193	41,623	39,126	36,778	34,571	32,497	30,547	
8	Additions	17,860	23,549	6,612	1,053	-	-	-	-	-	-	
9	CCA	536	1,746	2,546	2,623	2,497	2,348	2,207	2,074	1,950	1,833	20,359
10	Closing UCC	17,324	39,127	43,193	41,623	39,126	36,778	34,571	32,497	30,547	28,715	
	CCA Class 7 - Rate 15%											
11	Opening UCC	-	3,714	84,179	77,723	67,387	58,242	50,897	43,263	36,773	31,257	
12	Additions	4,015	87,592	6,671	1,429	1,042	1,504	-	-	-	-	
13	CCA	301	7,126	13,127	11,766	10,186	8,849	7,635	6,489	5,516	4,689	75,684
14	Closing UCC	3,714	84,179	77,723	67,387	58,242	50,897	43,263	36,773	31,257	26,569	
	CCA Class 8 - Rate 20%											
15	Opening UCC	-	10,481	20,954	17,563	14,043	11,235	8,988	7,190	5,752	4,602	
16	Additions	11,646	13,965	889	(8)	-	-	-	-	-	-	
17	CCA	1,165	3,493	4,280	3,512	2,809	2,247	1,798	1,438	1,150	920	22,811
18	Closing UCC	10,481	20,954	17,563	14,043	11,235	8,988	7,190	5,752	4,602	3,681	
	CCA Class 49 - Rate 8%											
19	Opening UCC	-	14,969	17,527	17,035	15,776	14,514	13,353	12,285	11,302	10,398	
20	Additions	15,593	3,912	948	108	-	-	-	-	-	-	
21	CCA	624	1,354	1,440	1,367	1,262	1,161	1,068	983	904	832	10,995
22	Closing UCC	14,969	17,527	17,035	15,776	14,514	13,353	12,285	11,302	10,398	9,566	
	Non-Deductible											
23	Opening	-	28,105	28,129	28,153	28,171	28,171	28,171	28,171	28,171	28,171	
24	Additions	28,105	24	24	18	-	-	-	-	-	-	
25	Closing	28,105	28,129	28,153	28,171	28,171	28,171	28,171	28,171	28,171	28,171	
	Total CCA											
26	Opening UCC	-	74,594	189,917	183,668	167,000	151,288	138,187	125,480	114,495	104,975	
27	Additions	77,219	129,042	15,144	2,600	1,042	1,504	-	-	-	-	
28	CCA	2,625	13,719	21,393	19,268	16,754	14,605	12,707	10,984	9,520	8,274	129,850
29	Closing UCC	74,594	189,917	183,668	167,000	151,288	138,187	125,480	114,495	104,975	96,701	

Utility Tax Timing Differences and CCA Continuity
Brantford-Kirkwall/Parkway D
2014 to 2023

Line No.	Particulars ($000's)	Actual 2014 (a)	Actual 2015 (b)	Actual 2016 (c)	Actual 2017 (d)	Forecast 2018 (e)	Forecast 2019 (f)	Forecast 2020 (g)	Forecast 2021 (h)	Forecast 2022 (i)	Forecast 2023 (j)	Total (k)
1	Depreciation	-	2,364	4,857	4,990	4,995	4,995	4,995	4,995	4,995	4,995	42,184
2	CCA	-	(10,387)	(20,004)	(18,147)	(15,917)	(13,965)	(12,276)	(10,811)	(9,539)	(8,433)	(119,479)
3	IDC & Other	-	(2,150)	(2)	-	-	-	-	-	-	-	(2,152)
4	Net Timing Differences	-	(10,172)	(15,149)	(13,157)	(10,922)	(8,970)	(7,280)	(5,816)	(4,544)	(3,437)	(79,447)
5	Utility Tax Timing Difference	-	(2,696)	(4,015)	(3,487)	(2,894)	(2,377)	(1,929)	(1,541)	(1,204)	(911)	(21,053)
6	Grossed Up Utility Tax Timing Difference	-	(3,668)	(5,462)	(4,744)	(3,938)	(3,234)	(2,625)	(2,097)	(1,638)	(1,239)	(28,644)
	CCA Continuity											
	CCA Class ECE - Rate 7%											
7	Opening UCC		-	1,213	1,128	1,049	976	907	844	785	730	
8	Additions		1,304	-	-	-	-	-	-	-	-	
9	CCA		91	85	79	73	68	64	59	55	51	626
10	Closing UCC		1,213	1,128	1,049	976	907	844	785	730	679	
	CCA Class 1 - Rate 6%											
11	Opening UCC		-	2,986	2,931	2,766	2,600	2,444	2,297	2,159	2,030	
12	Additions		3,078	128	11	-	-	-	-	-	-	
13	CCA		92	183	176	166	156	147	138	130	122	1,309
14	Closing UCC		2,986	2,931	2,766	2,600	2,444	2,297	2,159	2,030	1,908	
	CCA Class 7 - Rate 15%											
15	Opening UCC		-	71,825	66,341	56,645	48,148	40,926	34,787	29,569	25,134	
16	Additions		77,649	5,718	276	-	-	-	-	-	-	
17	CCA		5,824	11,203	9,972	8,497	7,222	6,139	5,218	4,435	3,770	62,279
18	Closing UCC		71,825	66,341	56,645	48,148	40,926	34,787	29,569	25,134	21,364	
	CCA Class 8 - Rate 20%											
19	Opening UCC		-	4,573	4,562	3,671	2,937	2,350	1,880	1,504	1,203	
20	Additions		5,081	1,004	24	-	-	-	-	-	-	
21	CCA		508	1,015	915	734	587	470	376	301	241	5,147
22	Closing UCC		4,573	4,562	3,671	2,937	2,350	1,880	1,504	1,203	962	
	CCA Class 49 - Rate 8%											
23	Opening UCC		-	92,914	87,529	80,588	74,141	68,210	62,753	57,733	53,114	
24	Additions		96,785	2,134	64	-	-	-	-	-	-	
25	CCA		3,871	7,518	7,005	6,447	5,931	5,457	5,020	4,619	4,249	50,118
26	Closing UCC		92,914	87,529	80,588	74,141	68,210	62,753	57,733	53,114	48,865	
	Non-Deductible											
27	Opening		-	1,264	1,265	1,265	1,265	1,265	1,265	1,265	1,265	
28	Additions		1,264	1	-	-	-	-	-	-	-	
29	Closing		1,264	1,265	1,265	1,265	1,265	1,265	1,265	1,265	1,265	
	Total CCA											
30	Opening UCC		-	174,774	163,755	145,984	130,066	116,101	103,825	93,014	83,475	
31	Additions		185,161	8,985	375	-	-	-	-	-	-	
32	CCA		10,387	20,004	18,147	15,917	13,965	12,276	10,811	9,539	8,433	119,479
33	Closing UCC		174,774	163,755	145,984	130,066	116,101	103,825	93,014	83,475	75,042	

Utility Tax Timing Differences and CCA Continuity
2016 Dawn-Parkway Expansion
2014 to 2023

Line No.	Particulars ($000's)	Actual 2014 (a)	Actual 2015 (b)	Actual 2016 (c)	Actual 2017 (d)	Forecast 2018 (e)	Forecast 2019 (f)	Forecast 2020 (g)	Forecast 2021 (h)	Forecast 2022 (i)	Forecast 2023 (j)	Total (k)
1	Depreciation	-	176	4,066	8,030	8,235	8,261	8,261	8,261	8,261	8,261	61,811
2	CCA	-	(758)	(17,030)	(31,540)	(28,913)	(25,717)	(22,821)	(20,285)	(18,060)	(16,106)	(181,229)
3	IDC & Other	-	(1,284)	(4,042)	-	-	-	-	-	-	-	(5,326)
4	Net Timing Differences	-	(1,866)	(17,005)	(23,510)	(20,679)	(17,456)	(14,560)	(12,024)	(9,800)	(7,845)	(124,745)
5	Utility Tax Timing Difference	-	(494)	(4,506)	(6,230)	(5,480)	(4,626)	(3,858)	(3,186)	(2,597)	(2,079)	(33,057)
6	Grossed Up Utility Tax Timing Difference	-	(673)	(6,131)	(8,477)	(7,456)	(6,294)	(5,250)	(4,335)	(3,533)	(2,828)	(44,976)
	CCA Continuity											
	CCA Class ECE - Rate 7%											
7	Opening UCC		-	-	840	1,239	1,152	1,072	997	927	862	
8	Additions		-	904	492	-	-	-	-	-	-	
9	CCA		-	63	93	87	81	75	70	65	60	594
10	Closing UCC		-	840	1,239	1,152	1,072	997	927	862	802	
	CCA Class 1 - Rate 6%											
11	Opening UCC		-	591	19,576	18,445	17,338	16,298	15,320	14,401	13,537	
12	Additions		609	19,609	45	-	-	-	-	-	-	
13	CCA		18	624	1,176	1,107	1,040	978	919	864	812	7,538
14	Closing UCC		591	19,576	18,445	17,338	16,298	15,320	14,401	13,537	12,725	
	CCA Class 7 - Rate 15%											
15	Opening UCC		-	5,396	105,117	96,081	81,669	69,418	59,005	50,155	42,631	
16	Additions		5,834	108,681	7,277	-	-	-	-	-	-	
17	CCA		438	8,961	16,313	14,412	12,250	10,413	8,851	7,523	6,395	85,555
18	Closing UCC		5,396	105,117	96,081	81,669	69,418	59,005	50,155	42,631	36,237	
	CCA Class 8 - Rate 20%											
19	Opening UCC		-	-	135	116	93	74	59	48	38	
20	Additions		-	150	9	-	-	-	-	-	-	
21	CCA		-	15	28	23	19	15	12	10	8	129
22	Closing UCC		-	135	116	93	74	59	48	38	30	
	CCA Class 49 - Rate 8%											
23	Opening UCC		-	7,242	169,566	164,748	154,084	141,757	130,417	119,983	110,385	
24	Additions		7,544	169,691	9,112	2,620	-	-	-	-	-	
25	CCA		302	7,367	13,930	13,285	12,327	11,341	10,433	9,599	8,831	87,413
26	Closing UCC		7,242	169,566	164,748	154,084	141,757	130,417	119,983	110,385	101,554	
	Non-Deductible											
27	Opening		-	-	9,771	9,985	9,985	9,985	9,985	9,985	9,985	
28	Additions		-	9,771	214	-	-	-	-	-	-	
29	Closing		-	9,771	9,985	9,985	9,985	9,985	9,985	9,985	9,985	
	Total CCA											
30	Opening UCC		-	13,229	305,006	290,615	264,321	238,605	215,784	195,499	177,438	
31	Additions		13,987	308,806	17,149	2,620	-	-	-	-	-	
32	CCA		758	17,030	31,540	28,913	25,717	22,821	20,285	18,060	16,106	181,229
33	Closing UCC		13,229	305,006	290,615	264,321	238,605	215,784	195,499	177,438	161,333	

Utility Tax Timing Differences and CCA Continuity
Burlington to Oakville
2014 to 2023

Line No.	Particulars ($000's)	Actual 2014 (a)	Actual 2015 (b)	Actual 2016 (c)	Actual 2017 (d)	Forecast 2018 (e)	Forecast 2019 (f)	Forecast 2020 (g)	Forecast 2021 (h)	Forecast 2022 (i)	Forecast 2023 (j)	Total (k)
1	Depreciation	-	-	821	1,668	1,717	1,732	1,732	1,732	1,732	1,732	12,864
2	CCA	-	-	(4,294)	(7,538)	(6,786)	(6,001)	(5,281)	(4,667)	(4,141)	(3,688)	(42,396)
3	IDC & Other	-	-	(795)	-	-	-	-	-	-	-	(795)
4	Net Timing Differences	-	-	(4,268)	(5,869)	(5,069)	(4,270)	(3,549)	(2,935)	(2,409)	(1,957)	(30,326)
5	Utility Tax Timing Difference	-	-	(1,131)	(1,555)	(1,343)	(1,132)	(941)	(778)	(638)	(518)	(8,036)
6	Grossed Up Utility Tax Timing Difference	-	-	(1,539)	(2,116)	(1,828)	(1,539)	(1,280)	(1,058)	(869)	(705)	(10,934)
	CCA Continuity											
	CCA Class ECE - Rate 7%											
7	Opening UCC			-	8,893	8,271	7,692	7,153	6,653	6,187	5,754	
8	Additions			9,563	-	-	-	-	-	-	-	
9	CCA			669	623	579	538	501	466	433	403	4,211
10	Closing UCC			8,893	8,271	7,692	7,153	6,653	6,187	5,754	5,351	
	CCA Class 1 - Rate 6%											
11	Opening UCC			-	199	173	163	153	144	135	127	
12	Additions			205	(14)	-	-	-	-	-	-	
13	CCA			6	12	10	10	9	9	8	8	71
14	Closing UCC			199	173	163	153	144	135	127	120	
	CCA Class 8 - Rate 20%											
15	Opening UCC			-	15,120	12,812	10,250	8,200	6,560	5,248	4,198	
16	Additions			16,800	796	-	-	-	-	-	-	
17	CCA			1,680	3,104	2,562	2,050	1,640	1,312	1,050	840	14,237
18	Closing UCC			15,120	12,812	10,250	8,200	6,560	5,248	4,198	3,359	
	CCA Class 49 - Rate 8%											
19	Opening UCC			-	46,527	44,673	42,540	39,137	36,006	33,126	30,476	
20	Additions			48,466	1,946	1,501	-	-	-	-	-	
21	CCA			1,939	3,800	3,634	3,403	3,131	2,880	2,650	2,438	23,875
22	Closing UCC			46,527	44,673	42,540	39,137	36,006	33,126	30,476	28,038	
	Non-Deductible											
23	Opening			-	3,188	3,188	3,188	3,188	3,188	3,188	3,188	
24	Additions			3,188	-	-	-	-	-	-	-	
25	Closing			3,188	3,188	3,188	3,188	3,188	3,188	3,188	3,188	
	Total CCA											
26	Opening UCC			-	73,927	69,117	63,832	57,831	52,550	47,883	43,743	
27	Additions			78,221	2,728	1,501	-	-	-	-	-	
28	CCA			4,294	7,538	6,786	6,001	5,281	4,667	4,141	3,688	42,396
29	Closing UCC			73,927	69,117	63,832	57,831	52,550	47,883	43,743	40,054	

Utility Tax Timing Differences and CCA Continuity
2017 Dawn-Parkway Expansion
2014 to 2023

Line No.	Particulars ($000's)	Actual 2014 (a)	Actual 2015 (b)	Actual 2016 (c)	Actual 2017 (d)	Forecast 2018 (e)	Forecast 2019 (f)	Forecast 2020 (g)	Forecast 2021 (h)	Forecast 2022 (i)	Forecast 2023 (j)	Total (k)
1	Depreciation	-	-	1,169	8,975	16,644	17,306	17,418	17,418	17,418	17,418	113,767
2	CCA	-	-	(5,403)	(42,293)	(71,210)	(64,244)	(55,578)	(47,664)	(40,911)	(35,148)	(362,451)
3	IDC & Other	-	-	(6,001)	(9,607)	(5,000)	-	-	-	-	-	(20,608)
4	Net Timing Differences	-	-	(10,235)	(42,925)	(59,566)	(46,938)	(38,160)	(30,245)	(23,493)	(17,729)	(269,292)
5	Utility Tax Timing Difference	-	-	(2,712)	(11,375)	(15,785)	(12,439)	(10,112)	(8,015)	(6,226)	(4,698)	(71,362)
6	Grossed Up Utility Tax Timing Difference	-	-	(3,690)	(15,476)	(21,476)	(16,923)	(13,758)	(10,905)	(8,470)	(6,392)	(97,092)
	CCA Continuity											
	CCA Class 1 - Rate 6%											
7	Opening UCC			-	496	67,417	63,372	59,570	55,996	52,636	49,478	
8	Additions			511	69,022	-	-	-	-	-	-	
9	CCA			15	2,100	4,045	3,802	3,574	3,360	3,158	2,969	23,024
10	Closing UCC			496	67,417	63,372	59,570	55,996	52,636	49,478	46,509	
	CCA Class 7 - Rate 15%											
11	Opening UCC			-	48,553	412,259	383,945	332,791	282,873	240,442	204,375	
12	Additions			52,490	401,069	36,243	6,960	-	-	-	-	
13	CCA			3,937	37,363	64,557	58,114	49,919	42,431	36,066	30,656	323,043
14	Closing UCC			48,553	412,259	383,945	332,791	282,873	240,442	204,375	173,719	
	CCA Class 8 - Rate 20%											
15	Opening UCC			-	2,795	2,958	2,367	1,893	1,515	1,212	969	
16	Additions			3,105	803	-	-	-	-	-	-	
17	CCA			311	639	592	473	379	303	242	194	3,132
18	Closing UCC			2,795	2,958	2,367	1,893	1,515	1,212	969	776	
	CCA Class 49 - Rate 8%											
19	Opening UCC			-	27,373	25,202	23,186	21,331	19,624	18,054	16,610	
20	Additions			28,514	19	-	-	-	-	-	-	
21	CCA			1,141	2,191	2,016	1,855	1,706	1,570	1,444	1,329	13,252
22	Closing UCC			27,373	25,202	23,186	21,331	19,624	18,054	16,610	15,281	
	Non-Deductible											
23	Opening			-	-	3,420	8,420	8,420	8,420	8,420	8,420	
24	Additions			-	3,420	5,000	-	-	-	-	-	
25	Closing			-	3,420	8,420	8,420	8,420	8,420	8,420	8,420	
	Total CCA											
26	Opening UCC			-	79,217	511,256	481,290	424,005	368,427	320,764	279,853	
27	Additions			84,620	474,333	41,243	6,960	-	-	-	-	
28	CCA			5,403	42,293	71,210	64,244	55,578	47,664	40,911	35,148	362,451
29	Closing UCC			79,217	511,256	481,290	424,005	368,427	320,764	279,853	244,705	

Utility Tax Timing Differences and CCA Continuity
Panhandle Reinforcement
2014 to 2023

Line No.	Particulars ($000's)	Actual 2014 (a)	Actual 2015 (b)	Actual 2016 (c)	Actual 2017 (d)	Forecast 2018 (e)	Forecast 2019 (f)	Forecast 2020 (g)	Forecast 2021 (h)	Forecast 2022 (i)	Forecast 2023 (j)	Total (k)
1	Depreciation	-	-	-	2,038	4,494	4,939	4,944	4,944	4,944	4,944	31,248
2	CCA	-	-	-	(9,589)	(19,691)	(19,208)	(17,054)	(15,180)	(13,560)	(12,151)	(106,433)
3	IDC & Other	-	-	-	(1,837)	-	-	-	-	-	-	(1,837)
4	Net Timing Differences	-	-	-	(9,388)	(15,197)	(14,269)	(12,109)	(10,236)	(8,615)	(7,207)	(77,022)
5	Utility Tax Timing Difference	-	-	-	(2,488)	(4,027)	(3,781)	(3,209)	(2,713)	(2,283)	(1,910)	(20,411)
6	Grossed Up Utility Tax Timing Difference	-	-	-	(3,385)	(5,479)	(5,145)	(4,366)	(3,691)	(3,106)	(2,598)	(27,770)
	CCA Continuity											
	CCA Class 1 - Rate 6%											
7	Opening UCC				-	12	9	7	6	5	4	
8	Additions				13	-	-	-	-	-	-	
9	CCA				1	2	2	1	1	1	1	10
10	Closing UCC				12	9	7	6	5	4	3	
	CCA Class 8 - Rate 20%											
11	Opening UCC				-	30,696	26,523	21,219	16,975	13,580	10,864	
12	Additions				34,107	2,185	-	-	-	-	-	
13	CCA				3,411	6,358	5,305	4,244	3,395	2,716	2,173	27,601
14	Closing UCC				30,696	26,523	21,219	16,975	13,580	10,864	8,691	
	CCA Class 14.1 - Rate 5%											
15	Opening UCC				-	2,845	2,702	2,567	2,439	2,317	2,201	
16	Additions				2,994	-	-	-	-	-	-	
17	CCA				150	142	135	128	122	116	110	903
18	Closing UCC				2,845	2,702	2,567	2,439	2,317	2,201	2,091	
	CCA Class 41 - Rate 25%											
19	Opening UCC				-	214	161	121	90	68	51	
20	Additions				245	-	-	-	-	-	-	
21	CCA				31	54	40	30	23	17	13	207
22	Closing UCC				214	161	121	90	68	51	38	
	CCA Class 49 - Rate 8%											
23	Opening UCC				-	142,799	170,261	157,120	144,550	132,986	122,347	
24	Additions				148,749	40,506	500	-	-	-	-	
25	CCA				5,950	13,044	13,641	12,570	11,564	10,639	9,788	77,195
26	Closing UCC				142,799	170,261	157,120	144,550	132,986	122,347	112,559	
	CCA Class 51 - Rate 6%											
27	Opening UCC				-	1,517	1,426	1,340	1,260	1,184	1,113	
28	Additions				1,564	-	-	-	-	-	-	
29	CCA				47	91	86	80	76	71	67	517
30	Closing UCC				1,517	1,426	1,340	1,260	1,184	1,113	1,047	
	Non-Deductible											
31	Opening				-	144	144	144	144	144	144	
32	Additions				144	-	-	-	-	-	-	
33	Closing				144	144	144	144	144	144	144	
34												
	Total CCA											
35	Opening UCC				-	178,228	201,227	182,519	165,465	150,285	136,725	
36	Additions				187,817	42,690	500	-	-	-	-	
37	CCA				9,589	19,691	19,208	17,054	15,180	13,560	12,151	106,433
38	Closing UCC				178,228	201,227	182,519	165,465	150,285	136,725	124,574	

ENBRIDGE GAS INC.
Answer to Interrogatory from
School Energy Coalition (SEC)

Reference: B1/1/1, p. 28

Question:

Please provide a detailed calculation showing the amounts that would be recovered from customers in each of 2019 – 2023 for the capital pass-through projects a) using the proposed one-time adjustment approach, and b) continuing to treat the projects as Y factor adjustments.

Response

Please see Attachment 1 for the capital pass-through project revenue requirement impact[1] using the proposed one-time adjustment in rates with continuing to pass-through utility tax timing differences only, and continuing to pass-through the actual revenue requirement of the projects.

The total revenue requirement difference of $33.8 million over the deferred rebasing period is required to support the level of capital investment prior to ICM funding as calculated by the ICM threshold value. As directed by the Board, Enbridge Gas has included the rate base and depreciation associated with the capital pass-through projects in calculating the ICM threshold value, resulting in a higher ICM threshold value. Without the proposed one-time adjustment, there would be an imbalance between the level of capital investment that can be supported by rates and the ICM threshold value calculation. Over the deferred rebasing period, the cumulative difference of the imbalance is approximately $410.0 million[2] of additional capital investment required prior to an ICM funding request. Please see Exhibit I.STAFF.8 a) for a description of the need for Enbridge Gas's proposed one-time adjustment and why continuing to pass-through the actual revenue requirement of the projects is not consistent with ICM threshold value calculation directive from the MAADs Decision.

[1] The capital pass-through revenue requirement is based on the forecast revenue requirement of each project included in the application.
[2] Exhibit I.STAFF.8, Attachment 1.

UNION RATE ZONES
Summary of 2019-2023 Capital Pass-Through Revenue Requirement Recovered from Customers
As Proposed vs. Pass-through of Annual Revenue Requirement

Line No.	Particulars ($000's)	As Proposed 2019 Forecast (a)	2020 Forecast (b)	2021 Forecast (c)	2022 Forecast (d)	2023 Forecast (e)	Total (f) = sum (a:e)	Pass-through of Annual Revenue Requirement 2019 Forecast (g)	2020 Forecast (h)	2021 Forecast (i)	2022 Forecast (j)	2023 Forecast (k)	Total (l) = sum (g:k)	Difference Total (m) = (f-l)
	Rate Base Investment													
1	Capital Expenditures	8,964	-	-	-	-		8,964	-	-	-	-		
2	Average Investment	1,596,906	1,596,906	1,596,906	1,596,906	1,596,906		1,596,906	1,558,331	1,515,453	1,472,576	1,429,698		
	Revenue Requirement Calculation:													
	Operating Expenses:													
3	Operating and Maintenance Expenses	4,604	4,604	4,604	4,604	4,604	23,021	4,604	4,769	4,863	4,960	5,060	24,256	(1,235)
4	Depreciation Expense (1)	42,741	42,741	42,741	42,741	42,741	213,704	42,741	42,883	42,883	42,883	42,883	214,271	(567)
5	Property Taxes	5,675	5,675	5,675	5,675	5,675	28,377	5,675	5,746	5,819	5,894	5,970	29,104	(727)
6	Total Operating Expenses (line 3 + line 4 + line 5)	53,021	53,021	53,021	53,021	53,021	265,103	53,021	53,397	53,565	53,736	53,913	267,631	(2,529)
	Required Return:													
7	Interest Expense	35,120	35,120	35,120	35,120	35,120	175,598	35,120	34,270	33,327	32,384	31,441	166,541	9,057
8	Equity Return	51,337	51,337	51,337	51,337	51,337	256,687	51,337	50,097	48,719	47,340	45,962	243,456	13,231
9	Total Required Return (line 7 + line 8) (2)	86,457	86,457	86,457	86,457	86,457	432,285	86,457	84,367	82,046	79,724	77,403	409,996	22,288
	Income Taxes:													
10	Income Taxes - Equity Return (3)	18,516	18,516	18,516	18,516	18,516	92,579	18,516	18,068	17,571	17,074	16,577	87,807	4,772
11	Income Taxes - Utility Timing Differences (4)	(36,415)	(29,865)	(24,051)	(19,054)	(14,752)	(124,138)	(36,415)	(29,865)	(24,051)	(19,054)	(14,752)	(124,138)	-
12	Total Income Taxes (line 10 + line 11)	(17,899)	(11,350)	(5,536)	(539)	3,764	(31,559)	(17,899)	(11,797)	(6,480)	(1,980)	1,825	(36,331)	4,772
13	Total Revenue Requirement (line 6 + line 9 + line 12)	121,578	128,128	133,942	138,939	143,241	665,828	121,578	125,967	129,130	131,480	133,140	641,296	24,532
14	Incremental Project Revenue (5)	4,340	4,340	4,340	4,340	4,340	21,702	4,340	5,415	6,243	7,069	7,895	30,962	(9,260)
15	Net Revenue Requirement (line 13 - line 14)	117,238	123,787	129,601	134,598	138,901	644,125	117,238	120,552	122,887	124,411	125,245	610,334	33,791

Notes:
(1) Depreciation expense at 2013 Board-approved depreciation rates.
(2) The required return assumes a capital structure of 36% common equity at the 2013 Board-approved return of 8.93% and 64% long-term debt. The assumed long-term debt for rates for 2019 are 3.82% for Parkway West and Parkway Growth projects, 3.36% for 2016 Dawn-Parkway Expansion and Burlington to Oakville projects, and 3.29% for 2017 Dawn-Parkway Expansion and Panhandle Reinforcement projects.
(3) Taxes related to the equity component of the return at a tax rate of 26.5%.
(4) Taxes related to the utility timing differences are negative as the capital cost allowance deduction in arriving at taxable income exceeds the provision of book depreciation in the year.
(5) Incremental project revenue reflected as an increase to Rate M12 and Rate C1 billing units used to set rates during the 2014-2018 IRM term except for the incremental revenue of the Panhandle Reinforecement Project. Incremental project revenue of the Panhandle Reinforcement Project treated as a reduction to the capital pass-through adjustment amount and includes incremental transmission and distribution margin.

ENBRIDGE GAS INC.
Answer to Interrogatory from
School Energy Coalition (SEC)

Reference: B1/1/1, p. 33

Question:

Please provide a side by side table showing the class allocation of DSM costs based on 2019 DSM Budget, vs. based on 2017 Actual DSM program costs.

Response

Please see Attachment 1, the 2017 actual DSM costs are still subject to audit, and Board approval.

ENBRIDGE GAS INC.
UNION RATE ZONES
Allocation of 2019 DSM Budget and 2017 DSM Actual Costs by Rate Class

Line No.	Particulars ($000s)	2019 Budget DSM Costs (1)	2017 Actual DSM Costs
		(a)	(b)
	Union North		
1	Rate 01	6,345	5,771
2	Rate 10	3,002	1,979
3	Rate 20	1,672	1,431
4	Rate 100	1,111	807
5	Total Union North	12,129	9,988
	Union South		
6	Rate M1	27,164	34,077
7	Rate M2	10,602	7,338
8	Rate M4 (2)	3,150	5,279
9	Rate M5 (2)	1,977	1,318
10	Rate M7	2,130	1,143
11	Rate T1	1,505	2,356
12	Rate T2	4,612	3,004
13	Total Union South	51,140	54,515
14	Total Union (line 5 + line 13)	63,269	64,503

Notes:
(1) Exhibit F1, Tab 2, Rate Order, Working Papers, Schedule 10, p. 1, column (b) with the exception of Rate M4 and Rate M5.
(2) The proposed 2019 allocation to Rate M4 and Rate M5 after the pooling adjustment is $4.674 million and $0.453 million, respectively.

ENBRIDGE GAS INC.
Answer to Interrogatory from
School Energy Coalition (SEC)

Reference: B1/1/1, App. H, p. 8

Question:

Please file a copy of the AFE manual.

Response

The Company declines to provide the AFE Manual given that it has no impact on 2019 Rates.

ENBRIDGE GAS INC.
Answer to Interrogatory from
School Energy Coalition (SEC)

Reference: B1/2/1, p. 4

Question:

Please explain why it would be appropriate for the Board to fund ICM for any of the deferred rebasing years when:

a. The forecast 2019-2023 average annual capital spending in the EGD Rate zone is $509.4 million, which is less than the $616.9 million annual average capital spending in the 2014-2018 period, in which EGD over-earned in every year.

b. The forecast 2019-2023 average annual capital spending in the Union Rate zone is $523.3 million, which is less than the $696.5 million annual average capital spending in the 2014-2018 period, in which Union over-earned in almost every year.

Response

The ICM funding mechanism was made available to Enbridge Gas in the MAADs and Rate-Setting Mechanism Decision and Order.[1] Enbridge Gas's evidence with respect to Need is provided at Exhibit B1, Tab 2, Schedule 1, page 20. Within the Need section is a description of the Means Test, which legacy EGD and Union pass by not exceeding 300 basis points above the deemed return on equity in their most recent Earnings Sharing and Deferral and Variance Account Clearance applications.[2]

[1] EB-2017-0306/EB-2017-0307 Decision and Order, August 30, 2018, pages 32 to 34.
[2] Exhibit B1, Tab 2, Schedule 1, Appendix C.

ENBRIDGE GAS INC.
Answer to Interrogatory from
School Energy Coalition (SEC)

Reference: B1/2/1, p. 16

Question:

Please explain how there can be 2019 spend in 2014-2018 capital pass-through projects, which by definition should be completed and in-service no later than the end of 2018.

Response

There are often carry-over costs that occur after a project goes into service. Examples of these costs include activities such as construction clean up, restoration, baseline integrity inspections, painting, installation of anodes and other.

ENBRIDGE GAS INC.
Answer to Interrogatory from
School Energy Coalition (SEC)

Reference: B1/2/1, p. 18

Question:

Please confirm that the Sudbury Replacement project does not qualify under the Board-approved ICM for the Applicant. If the Applicant believes it does qualify, please provide a detailed explanation. If the Applicant believes it does not qualify, please explain the precise relief the Applicant is seeking from the Board, e.g. a) inclusion of the project in 2019 opening rate base, and a concomitant base year adjustment, b) deeming of the project to have come into service in 2019 and thus qualify for ICM treatment, c) retroactively deeming the ICM mechanism and the capital pass-through mechanism to both apply during 2018 year, d) exempting the Sudbury Replacement project from the $5 million impact requirement of the capital pass-through mechanism, or e) any other relief the Applicant believes is appropriate. SEC is seeking in this question to more clearly understand the exact exception that the Applicant is seeking from the Board from the normal rules and principles that would be applied to rate recovery for this project, in order to understand the implications of that exception both for the Applicant and for other utilities seeking exceptions to the rules.

Response

Please see Exhibit I.STAFF.24.

ENBRIDGE GAS INC.
Answer to Interrogatory from
School Energy Coalition (SEC)

Reference: B1/2/1, p. 22

Question:

Please provide a side by side table showing, for each of the proposed ICM projects:

a. The budget for the project provided to the Board in the first filing for the project (e.g. EB-2018-0108 for the Don River Replacement, etc.).

b. The budget for the project in this Application, for which ICM approval is being sought.

c. An explanation for any material budget variations.

Response

Please see the response at Exhibit I.EP.16.

ENBRIDGE GAS INC.
Answer to Interrogatory from
School Energy Coalition (SEC)

Reference: B1/2/1, p. 29, 31

Question:

Please confirm that, excluding the Sudbury project, the 2019 revenue requirement impact of the ICM projects proposed would be $3.23 million credit to customers, and the 2019-2023 revenue requirement impact of the ICM projects proposed would be $52.395 million recovery from customers.

Response

Confirmed.

ENBRIDGE GAS INC.
Answer to Interrogatory from
School Energy Coalition (SEC)

Reference: B1/2/1, p. 31

Question:

Please confirm that the Applicant is seeking to accelerate $4.9 million of 2020 capital expenditures into 2019 for the purpose of determining rates. Please explain why that is appropriate.

Response

Enbridge Gas has not included the 2020 capital forecast associated with the 2019 ICM projects of $4.9 million in the 2019 revenue requirement of the projects for the purpose of determining 2019 rates. The $4.9 million represents the 2020 in-service capital of the ICM projects, and is reflected in the revenue requirement of each project beginning in 2020. The detailed incremental revenue requirement of the ICM projects is filed at Exhibit B1, Tab 2, Schedule 1, Appendix E.

ENBRIDGE GAS INC.
Answer to Interrogatory from
School Energy Coalition (SEC)

Reference: B1/2/1, p. 32

Question:

Please confirm that the Applicant is seeking to defer $3.2 million of 2019 credits to customers to 2020 for the purpose of determining rates. Please explain why that is appropriate.

Response

Please see Exhibit I. BOMA.7.

ENBRIDGE GAS INC.
Answer to Interrogatory from
School Energy Coalition (SEC)

Reference: B1/2/1, App. D

Question:

SEC is seeking to better understand the Union earnings-sharing calculation for 2017. In EB-2017-0306/7 (Ex. C.SEC.19 on March 23, 2018), Union reported 2017 operating revenue of $2,118,989 (all figures $000s), and that is the same amount showing in the current Application. The total operating expenses, however, was reported in the previous case as $1,769,137, and is now reported as $1,772,606, a decrease in earnings of about $3.5 million. The expected tax provision was reported in the previous case as $1.8 million credit, but is now reported as a $5.0 million credit, an increase in earnings of about $3.2 million. Please provide details of these changes from the previous reported figures to the current reported figures for 2017.

Response

The primary cause for the variances in the quoted amounts results from the comparison of dissimilar values. Within Union's preliminary[1] 2017 actual utility results, presented as part of the response to SEC interrogatory #19 Attachment 1 (Exhibit C.SEC.19, Attachment 1) within the EB-2017-0306/7 proceeding, $1,769,137 thousand reflected a Cost of Service value, inclusive of total Operating Expenses of $1,772,786 thousand, Other Expenses of $1,441 thousand, and Income Taxes on earnings of ($5,090) thousand, as can be seen in Attachment 2 to that interrogatory response. By comparison, the $1,772,606 shown in Exhibit B1, Tab 2, Schedule 1, Appendix D of this proceeding, which reflects Union's final 2017 utility results as were filed at Exhibit A, Tab 2, Appendix B, Schedule 1 of the EB-2018-0105 proceeding, only reflects total Operating Expenses.

Table 1 below provides a comparison of the preliminary cost of service amounts reported in Exhibit C.SEC.19 (Attachments 1 and 2) of the EB-2017-0306/7 proceeding, as compared to final actual 2017 amounts presented at Exhibit B1, Tab 2, Schedule 1, Appendix D of this proceeding (as were filed at Exhibit A, Tab 2, Appendix B, Schedule 1 of the EB-2018-0105 proceeding).

[1] EB-2018-0306/0307, Exhibit C.SEC.19, Attachment 2, Note (5).

Table 1
Calculation of Cost of Service for 2017

Line No.	Particulars ($ 000's)	EB-2017-0306/7 C.SEC.19	Actual	Difference
1	Total Operating Expenses	1,772,786	1,772,606	180
2	Income Taxes	(5,090)	(5,047)	(43)
3	Total Other	1,441	1,441	(0)
4	Cost of Service (line 1 + line 2 + line 3)	$ 1,769,137	$ 1,769,001	$ 136

The small change between the preliminary and final Cost of Service is primarily attributable to the removal of $0.180 million in legal fees related to the amalgamation from utility operating expenses, and its corresponding impact on income taxes on earnings.

With respect to the referenced tax amounts, the cause of the variance is again due to the comparison of dissimilar values. Within Union's preliminary 2017 actual utility results, presented as part of the response to SEC interrogatory #19 Attachment 1 (Exhibit C.SEC.19 Attachment 1) within the EB-2017-0306/7 proceeding, ($1,800) thousand reflected the provision of income taxes required to gross-up the net sufficiency amount, whereas the ($5,047) shown in Exhibit B1, Tab 2, Schedule 1, Appendix D of this proceeding, which reflects Union's final 2017 utility results as were filed at Exhibit A, Tab 2, Appendix B, Schedule 1 of the EB-2018-0105 proceeding, reflects the provision for income taxes on earnings (for which comparable values are shown in Table 1 above).

Table 2 below provides a comparison of the preliminary 2017 calculation of the provision for income taxes required to gross-up the net sufficiency amount as reported in Exhibit C.SEC.19 (Attachment 1) of the EB-2017-0306/7 proceeding, as compared to the calculation of the final actual 2017 amount which was presented at Exhibit A, Tab 2, Appendix A of the EB-2018-0105 proceeding.

For reference, Exhibit A, Tab 2, Appendix A from the EB-2018-0105 proceeding provides a calculation of Union's final actual 2017 revenue sufficiency, which is in a similar format to the preliminary actual results which were presented in the response to SEC interrogatory #19 Attachment 1 (Exhibit C.SEC.19 Attachment 1), within the EB-2017-0306/7 proceeding.

Table 2

Calculation of Provision for Income Taxes on Deficiency/(Sufficiency) for 2017

Line No.	Particulars ($ 000's)	EB-2017-0306/7 C.SEC.19	Actual	Difference
1	Revenue Deficiency/(Sufficiency) after tax	(4,993)	(5,112)	(119)
2	Tax Prorated (1-.265)	0.735	0.735	0.735
3	Distribution Revenue Deficiency/(Sufficiency) (line 1/line 2)	(6,793)	(6,955)	(162)
4	Provision for Income Taxes on Deficiency/(Sufficiency) (line 3 - line 1)	$ (1,800)	$ (1,843)	$ (43)

ENBRIDGE GAS INC.
Answer to Interrogatory from
School Energy Coalition (SEC)

Reference: B1/2/1, App. E, p. 2

Question:

Please confirm that the $2.6 million of grossed-up tax savings in 2018 are, under the Applicant's proposal, remaining to the benefit of the shareholder. Please confirm that the extra taxes payable in the future of $2.6 million because of that accelerated depreciation will be paid by the customers in rates.

Response

Enbridge Gas confirms that no revenue requirement impacts (i.e., return on rate base, operating expenses, or income tax benefit/requirement), related to the Sudbury Replacement project, were included in Union's 2018 rates for recovery from customers. As seen in the referenced exhibit, the forecast total 2018 revenue requirement was a cost $0.1 million.

With respect to the 2019 to 2023 revenue requirement for the Sudbury Replacement Project (including the tax requirement which will reflect the impact of any reversal of tax timing differences), Enbridge Gas confirms that its ICM proposal, to build the forecast annual revenue requirement into the annual ICM rate rider, combined with the establishment of an ICM deferral account to capture the variance between the actual ICM project revenue requirement and the actual ICM revenues collected, would result in customers paying the actual cost of the approved ICM project, subject to disposition of the deferral account.

ENBRIDGE GAS INC.
Answer to Interrogatory from
School Energy Coalition (SEC)

Reference: F/1/1/5, p. 4

Question:

Please compare the Rate 6 usage forecast of 4,911,864 103m3 in 2019 to the Applicant's most current forecast of actual usage in 2019 from Rate 6 customers.

Response

The current 2019 volume forecast for Rate 6 is 4,923,606 10^3m^3.

ENBRIDGE GAS INC.
Answer to Interrogatory from
School Energy Coalition (SEC)

Reference: F1/1/7, p. 2-3

Question:

In EB-2017-0086, the EGD Draft Rate Order shows an allocation of $$86.9 million of DSM costs to rate classes (Ex. G2/6/4). Please reconcile that with the allocation of $67.6 million to rate classes in the current reference, at page 2. Please provide a reference for the same allocation as that found on page 3 of the current reference, but in the EB-2017-0086 case, deriving the DSM unit rate for 2018 rates.

Response

In the Board's Decision and Order for the approval of 2015-2020 demand side management plans (EB-2015-0029/EB-2015-0049, Decision and Order, page 1), the 2018 EGD approved DSM budget is $67.6 million.

In the EB-2017-0086 draft rate order (Exhibit G2, Tab 6, Schedule 4, page 1), the fully allocated DSM costs of $86.9 million was comprised of DSM program and general cost of $67.6 million (i.e., the Board-approved DSM budget), and allocated overheads (benefit costs) of $5.17 million and administrative and general (A&G) of $14.17 million) for a total of $86.9 million. Note that the EGD rate zone was subject to Custom Incentive Regulation framework for the 2014 to 2018 period where the Board approved the cost elements for the derivation of the allowed revenue for each year of the Custom IR period and the Company used the fully allocated cost study to allocate the allowed revenue to the customer classes for rate setting purposes.

The allocation of $67.6 million at page 2 (Exhibit F1, Tab 1, Schedule 7) represents the allocation of DSM program and general costs from EB-2017-0086, Draft Rate Order, Exhibit G2, Tab 6, Schedule 4, page 1. For example, for Rate 6 customers the amount is the sum of the first two line items of the referenced exhibit (i.e. $18.1 million + $3.75 million = $21.85 million).

Note that the Board approved Y factor treatment for DSM budget costs in the MAADs and Rate-Setting Mechanism proceeding.[1]

Consistent with the Y factor treatment, the Board-approved 2018 DSM budget of $67.6 million was removed from rates and updated with the Board-approved 2019 DSM budget of $66.4 million, which was approved in EB-2015-0029/EB-2015-0049.

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

ENBRIDGE GAS INC.
Answer to Interrogatory from
School Energy Coalition (SEC)

Reference: F1/2/10, p. 3-4

Question:

Please confirm that the DSM allocation to Rate 01 declined from $9.124 million in 2018 [EB-2017-0087, Working Papers, Schedule 3] to the current $6.345 million, and the allocation to Rate M1 increased from $24,375 million in 2018 [same reference] to the current $27.164 million. Please explain those changes in allocation. Please provide a reference (in EB-2017-0087 or elsewhere) that shows the derivation of the 2018 unit rates for DSM, with similar granularity to the current reference.

Response

Confirmed.

The change in Rate 01 and Rate M1 DSM costs is driven by Enbridge Gas's proposal to allocate the 2019 DSM budget costs based on the 2017 actual DSM program costs. Enbridge Gas has updated the allocation in the current application to reflect a forecast of the 2019 DSM budget consistent with the use of 2019 forecast billing units to derive the DSM unit rates.

This proposal also reduces the variance between rate classes that would otherwise be recorded in the DSM Variance Account ("DSMVA")[1] (Account No. 179-111) and disposed of as part of the annual DSM Deferral and Variance Account proceedings. The change in the DSM costs for Rate 01 and Rate M1 is consistent with the amounts disposed of in Union's 2015 and 2016 DSM Deferral proceeding (EB-2017-0323 and EB-2018-0300, respectively). Please see Table 1 for a summary of the DSM budget costs for Rate 01 and Rate M1.

[1] The DSMVA records the difference between the allocated DSM budget costs included in rates and the actual DSM program costs for each rate class.

Table 1
UNION RATE ZONES
Comparison of 2019 DSM Budget Allocation Change and DSM Variance Account Balances

Line No.	Particulars ($000's)	Proposed 2019 DSM Budget in Rates (1)	Approved 2018 DSM Budget in Rates (2)	Change	DSM Variance Account (179-111) 2016 Approved Balance (3)	DSM Variance Account (179-111) 2015 Approved Balance (4)
		(a)	(b)	(c) = (a - b)	(d)	(e)
1	Rate 01	6,345	9,124	(2,780)	(3,223)	(1,102)
2	Rate M1	27,164	24,375	2,788	2,595	2,511

Notes:
(1) Exhibit F1, Tab 2, Rate Order, Working Papers, Schedule 10, p. 1, column (b).
(2) EB-2017-0087, Rate Order, Working Papers, Schedule 11, column (b).
(3) EB-2018-0300, Exhibit A, Tab 4, Appendix A, Schedule 1.
(4) EB-2017-0323, Rate Order, Working Papers, Schedule 1.

Please see Attachment 1 for the derivation of the Rate 01 and Rate M1 2018 DSM unit rates.

ENBRIDGE GAS INC.
UNION RATE ZONES
Derivation of 2018 Demand Side Management ("DSM") Rates

Line No.	Particulars	2018 Approved Forecast Usage (1) (10^3m^3)	2018 DSM Budget (2) ($000s)	2018 DSM Rate (cents / m^3)
		(a)	(b)	(c) = (b / a)
	Union North			
	Rate 01 Small Volume General Service			
	Monthly Delivery Charge			
1	First 100 m^3	261,357	2,818	1.0781
2	Next 200 m^3	296,764	3,118	1.0505
3	Next 200 m^3	129,460	1,304	1.0069
4	Next 500 m^3	88,423	855	0.9670
5	Over 1,000 m^3	110,336	1,030	0.9339
6	Total Rate 01	886,340	9,124	1.0294
	Union South			
	Rate M1 - Small Volume General Service			
	Monthly Delivery Commodity Charge			
7	First 100 m^3	845,823	8,101	0.9578
8	Next 150 m^3	751,066	6,822	0.9082
9	All over 250 m^3	1,211,407	9,453	0.7803
10	Total - Rate M1	2,808,296	24,375	0.8680

Notes:
(1) EB-2018-0087, Rate Order, Working Papers, Schedule 4, column (r).
(2) EB-2018-0087, Rate Order, Working Papers, Schedule 4, column (k).

ENBRIDGE GAS INC.
Answer to Interrogatory from
School Energy Coalition (SEC)

Reference: F1/2/10, p. 3-4

Question:

Please provide a breakdown of the DSM budget allocated to Rate 01 and Rate M1 between residential and non-residential spending. For non-program DSM costs allocated to those classes, please identify them separately and divide them in the same proportion as the program costs. Please calculate, based on the proposed DSM unit rates, the amounts of the allocated costs in each of those classes that are expected to be collected in 2019 from residential vs. non-residential customers.

Response

Please see Table 1 for a breakdown of the 2019 Rate 01 and Rate M1 DSM budget. Attachment 1 provides the forecast amount of 2019 DSM budget to be recovered from residential and non-residential customers.

Table 1
Summary of 2019 DSM Budget Allocation

Line No.	Particulars ($000's)	Rate 01	Rate M1
		(a)	(b)
1	Residential Program Costs	1,395	12,873
2	Residential Non-Program Costs	183	1,962
3	Non-Residential Program Costs	1,455	3,988
4	Non-Residential Non-Program Costs	70	278
5	Low-Income Costs (1)	3,241	8,063
6	Total 2019 DSM Budget Allocation (2)	6,345	27,164

Notes:
(1) Allocation of low-income costs to Rate 01 and Rate M1.
(2) EB-2018-0305, Exhibit F1, Tab 2, Rate Order, Working Papers, Schedule 10, column (b), line 1 and line 6.

ENBRIDGE GAS INC.
Union Rate Zones
Forecast Recovery of 2019 DSM Budget - Residential and Non-Residential Customers

Line No.	Particulars	Proposed 2019 DSM Rate (cents/m^3) (1)	Residential: 2019 Forecast Usage (10^3m^3)	Residential: Forecast DSM Budget Recovery ($000's)	Non-Residential: 2019 Forecast Usage (10^3m^3)	Non-Residential: Forecast DSM Budget Recovery ($000's)	Total Forecast DSM Budget Recovery ($000's) (2)
		(a)	(b)	(c) = (a x b)	(d)	(e) = (a x d)	(f) = (c + e)
	Union North						
	Rate 01 Small Volume General Service						
	Monthly Delivery Charge						
1	First 100 m^3	0.6795	284,146	1,931	23,807	162	2,092
2	Next 200 m^3	0.6621	299,243	1,981	36,335	241	2,222
3	Next 200 m^3	0.6346	100,612	638	27,955	177	816
4	Next 500 m^3	0.6093	37,710	230	48,077	293	523
5	Over 1,000 m^3	0.5885	6,722	40	110,831	652	692
6	Total - Rate 01		728,432	4,820	247,006	1,525	6,345
	Union South						
	Rate M1 - Small Volume General Service						
	Monthly Delivery Commodity Charge						
7	First 100 m^3	0.9753	931,790	9,088	69,711	680	9,767
8	Next 150 m^3	0.9246	779,871	7,211	80,703	746	7,957
9	All over 250 m^3	0.7937	597,651	4,744	591,576	4,695	9,439
10	Total - Rate M1		2,309,312	21,042	741,990	6,121	27,164

Notes:
(1) EB-2018-0305, Exhibit F1, Tab 2, Rate Order, Working Papers, Schedule 10, column (d).
(2) EB-2018-0305, Exhibit F1, Tab 2, Rate Order, Working Papers, Schedule 10, column (c).

ENBRIDGE GAS INC.
Answer to Interrogatory from
Vulnerable Energy Consumers Coalition (VECC)

Reference: Exhibit A1/T5/S1/pg.22

Question:

a) With respect to the Conditions of Service for the EGD Rate Zone please explain why it is a pre-requisite to have an account with a financial institution for an eligible low-income customer to have a security deposit waived. Does this provision also apply to the Union Rate Zone?

b) Is the United Way Greater Simcoe County the LEAP administrator for both the EGD and Union Rate Zones. If not please provide the administrator name(s) for the Union Rate Zones.

Response

a) The question misstates the condition. It is the reverse where the condition is no account with a financial institution. This does not apply for the Union rate zones. The criteria will be reviewed and changed to be consistent with the new Customer Service Rules.

b) Yes, however they have changed their name to United Way Simcoe Muskoka.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Vulnerable Energy Consumers Coalition (VECC)

Reference: Exhibit A1/T5/S1/pg.23

Question:

a) Please provide the number (by category) of complaints escalated to the Enbridge Customer Ombudsman's Office for the last calendar year (2018)

b) Does the Union Rate Zone have a similar office? If so, please a similar report as in a) for this Rate Zone.

Response

a-b) Please see tables below for the number of complaints:

EGD Rate Zone

Complaints	2018
Billing	3870
Collections	1382
Operations	1510
Open Bill	1204
Other	181
Total 2018	8147

Union Rate Zone

Complaints	2018
Billing	1697
Collections	1345
Operations	741
Open Bill	0
Other	1221
Total 2018	5004

ENBRIDGE GAS INC.
Answer to Interrogatory from
Vulnerable Energy Consumers Coalition (VECC)

Reference: Exhibit A1/T5/S3/pg.23

Question:

a) The Security Deposit and Low-Income Customer Policies of EGI for its two different rate zones differ. Please explain why and what plans are being made to harmonize these specific conditions of service provisions.

Response

The exact details on operating policies for the different rate zones differ due to each legacy company's interpretation of guidelines or program parameters.

With the implementation of the OEB's new customer service rules, Enbridge Gas will be harmonizing business practices and policies where differences exist. [1] However, there may still be differences where there are rate implications and Enbridge Gas maintains different rate zones, e.g. fees like new account charge.

[1] EB-2017-0183, Notice of Amendment, March 14, 2019.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Vulnerable Energy Consumers Coalition (VECC)

Reference: Exhibit A1/T5/S3/pg.23

Question:

a) With respect reasons for the disconnection of service please explain (provide an example) of what constitutes a "fraudulent use of gas." If this is meant to address service where illegal activity are suspected please explain what evidence of the activity in question is required.

Response

The most obvious example would be altering the gas service to circumvent the gas meter. A disconnection order would be executed if Enbridge Gas personnel encounter a gas service which has been tampered or altered with. Situations where a meter is unlocked, and it is documented that a lock work order was previously completed would also qualify as fraudulent use of gas. In these cases there is no active customer account and required appliance inspections have not been completed.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Vulnerable Energy Consumers Coalition (VECC)

Reference: Exhibit A1/T5/S2/pg.7

Question:

The preface to the EGD Conditions of Service state:

> We reserve the right to modify the contents of the Conditions of Service at any time. These Conditions of Service are meant as guidelines and do not supersede any terms and conditions set out in Enbridge's Rate Handbook, or agreed to in our contracts with you.

a) Is it EGI's position that all of the provisions of its Conditions of Service (both Rate Zones) may be changed without prior approval of the Ontario Energy Board?

b) If, it is EGI's position that a subset of the provisions require Board approval whereas other provisions do not, please identify the provisions in question.

Response

a-b) In accordance with the Board's *Gas Distribution Access Rule*, Enbridge Gas must file a copy of its Customer Service Policy (i.e., Enbridge Gas's Conditions of Service) with the Board when revised. Board approval of revisions is not required.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Vulnerable Energy Consumers Coalition (VECC)

Reference: Exhibit B1/T1/S1/pg.5 Table 3

Question:

a) Please explain why EGI requires two OEB Cost Assessment Variance Accounts if there is a single Utility being assessed OEB costs upon amalgamation of the former utilities

b) The OEB Cost Assessment Variance accounts were generically established by the Board in order to capture the change in the Board's assessment methodology. Please confirm (or otherwise explain) that this change in methodology is from an assessment based on net revenues to, now, the 3 year average of customer numbers.

c) Please explain how the new variance accounts distinguishes between the normal expected variance (formerly in revenues – now under the revised methodology in number of customers) from the variance due only to the change in assessment methodology.

d) Is it EGI's understanding that the change in methodology affected both the inter and intra assessed OEB regulated payers? That is, did the change in methodology only affect the amount paid as between natural gas utilities or both that and the amounts paid as between gas utilities and other assessed payers (e.g. electricity distributors, transmitters, and other licencees)?

Response

a) Enbridge Gas's application includes the continuation of two OEB Cost Assessment Variance Accounts, one for the EGD rate zone, and one for the Union rate zones as it aligns with the Board's EB-2017-0306 / EB-2017-0307 Decision and Order which approved the continuation of the two accounts.

b) Having reviewed the OEB's February 9, 2016 letter regarding Revisions to the Ontario Energy Board Cost Assessment Model, as well as the supporting MNP Final Executive Report, titled Cost Assessment Model Review, dated December 11, 2015, Enbridge Gas's understanding is that multiple revisions were made to the Board's Cost Assessment Model. One of the revisions made was to update the electricity distribution and gas distribution intra class cost allocations from a revenue based allocation to a 3 year rolling average customer based allocation methodology. However, one of the other revisions to the model was an update of the OEB's direct cost allocations, which impacted the inter payor class allocations, resulting in more costs allocated to the gas utilities.

c) Since the Board's establishment of the account in 2016, both legacy EGD and legacy Union, when calculating amounts to be recorded in their respective accounts compared their current quarterly assessed costs under the new methodology against an amount that was included in rates and reflective of the Board's costs under the old cost allocation methodology.

d) Further to the response in part b), Enbridge Gas's understanding is that the revisions to the Board's Cost Assessment Model impacted both inter and intra regulated payor class allocations, with the larger impact to gas utilities resulting from inter payor class changes (i.e. more costs assessed to gas utilities, with less going to most of the other payor classes as a result of revisions to direct cost allocations).

ENBRIDGE GAS INC.
Answer to Interrogatory from
Vulnerable Energy Consumers Coalition (VECC)

Reference: Exhibit B1, Tab 2, Schedule 1

Question:

a) Why did EGI not calculate two materiality thresholds – one for distribution function and another for transmissions (e.g. Dawn-Parkway) capital expenditures?

b) For the purpose of calculating and ICM/ACM threshold value why should EGI's transmission business not be considered analogous to Hydro One Inc. where the threshold values for the transmission business would be calculated separately from those of the distribution operations?

c) Is it possible to amend Table 3 to show the ICM threshold Capital Expenditure Calculation by Rate Zone and for the Union Rate Zone by transmission and distribution functions? If yes, please provide that calculation. If not, please explain the impediments to making this calculation.

Response

a-c) The availability of ICM to Enbridge Gas was litigated in the MAADs and Rate Setting Mechanism proceeding, and approved by the Board in its Decision and Order, dated August 30, 2018.[1]

[1] EB-2017-0306/EB-2017-0307, OEB Decision dated August 30, 2018.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Vulnerable Energy Consumers Coalition (VECC)

Reference: Exhibit B/T2/S1/pgs. 12-

Question:

a) EGI explains that it has used a weather-normalized revenue for the calculation of the growth factor. Is the weather normalization methodology used for the EGD and Union Rate Zones the same?

b) For the both rate zones please calculate the growth rate if only revenues derived from the fixed charge were used in the calculation (i.e. showing the growth in fixed charge revenues only).

Response

a) No, the weather normalization methodology for the EGD and Union rate zones are not the same, however, Board approved weather methodologies were used for both. Weather-normalized revenues are derived by using the Board approved degree days methodologies for Union rate zones which is the 50:50 (average of 20 year trend and 30 year moving average), for EGD rate zone are the 50:50 Hybrid (average of 20 year trend and 10 year moving average) for the Central region, the De Bever with trend for the Eastern region and the 10 year moving average for the Niagara region.

b) Assuming that the general service fixed charges are the only component of the growth factor, that is, it does not include the variable revenue, the contract market revenue and the ex-franchise market revenue, the estimated results are as follows:

Union rate zones average growth factor from 2013 to 2017	: 1.42%
EGD rate zone growth factor from 2017 to 2018	: 1.14%

ENBRIDGE GAS INC.
Answer to Interrogatory from
Vulnerable Energy Consumers Coalition (VECC)

Reference: Exhibit B1/T2/S1/pg.19

Question:

At the above reference the evidence states:

Given the magnitude of the $95.3 million investment in the Sudbury Replacement project, incremental funding of the project is required. The cumulative revenue requirement of the project from 2018 through 2023 is over $47 million. Union was not able to reprioritize 2018 Capital investment in order to fund this investment using existing rates.

a) Please provide the list of projects that were considered (and subsequently rejected as per the evidence above) in considering the need for the Sudbury Replacement Project.

b) Please provide the minutes/presentation or other evidence that is demonstrative of the exercise EGI went through to consider what projects might be deferred in order to complete the Sudbury Replacement Project without the need for an ICM.

Response

a) The alternative projects that were considered for the Sudbury Replacement project can be found on pages 6 and 7 of pre-filed evidence in the EB-2017-0180 proceeding.

b) As per section 4.2, Asset Planning[1], the Sudbury Replacement project was risk assessed using the Union rate zones' Risk Matrix[2] and assigned priority based on the "Priority Ranking Scale" criteria.[3] All projects identified in the planning process

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[1] Exhibit C1, Tab 3, Schedule 1 pages 39 - 58.
[2] Ibid., Figure 4.2.1.1.3.2, page 53.
[3] Ibid., Table 4.2.1.1.4.1, page 57.

are assigned priority based on the “Priority Ranking Scale” without consideration of the funding mechanism.

Please see Exhibit I.STAFF.24 for further information with respect to ICM funding for the Sudbury Replacement project.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Vulnerable Energy Consumers Coalition (VECC)

Reference: Exhibit B1/T2/S1/pg.33

Question:

a) With respect to the Sudbury Replacement project please compare/contrast the proposed cost allocation methodology (peak demand and average demand factor) with the method used to allocate the existing Sudbury assets being replaced.

b) Please do the same for the Don River Replacement, and the Kingsville and Stratford Replacement projects, pointing out any differences (if any) between how the existing and replacement assets are allocated.

Response

a) The proposed cost allocation methodology of the Sudbury Replacement project in the Union North rate zone uses the same allocation methodology as the existing Sudbury assets being replaced. Both the project and existing assets are categorized as joint-use distribution mains and are allocated to Union North rate classes in proportion to peak and average day demands. The allocation of the existing Sudbury assets was approved by the Board as part of legacy Union's 2013 cost allocation study (EB-2011-0210). Enbridge Gas has updated the allocation factor in the current application to reflect the 2019 forecast consistent with the use of 2019 forecast billing units to derive the ICM unit rates.

b) The proposed cost allocation methodology of the Don River Replacement project in the EGD rate zone uses the same allocation methodology as the existing Don River crossing assets being replaced. Both the project and existing assets are categorized as extra high pressure mains greater than 4 inches in diameter and are allocated to EGD rate classes in proportion to peak delivery demands on the extra high pressure system greater than 4 inches in diameter. The allocation of the existing Don River crossing assets was approved by the Board as part of legacy EGD's 2018 cost allocation study (EB-2017-0086).

The proposed cost allocation methodology of the Kingsville and Stratford Reinforcement projects in the Union South rate zone uses the same allocation methodology as existing other transmission assets. Both the project and existing other transmission costs are categorized as other transmission mains and are allocated to Union South rate zone rate classes in proportion to in-franchise design day demands. The allocation of the existing other transmission assets was approved by the Board as part of legacy Union’s 2013 cost allocation study (EB-2011-0210).

ENBRIDGE GAS INC.
Answer to Interrogatory from
Vulnerable Energy Consumers Coalition (VECC)

Reference: Exhibit C1/T1/S1 Figures 6 (pg. 39) and 9 (pg.51)

Question:

a) Please clarify the relationship between these two figures. Specifically does Figure 6 show the forecast total EGI capital expenditures net of ICM spending? If yes, please explain why the some annual totals in Figure 6 are less than those in Figure 9 (see, for example, 2020 $1037 vs $1024 ENBRIDGE GAS Total).

Response

a) The difference between these two figures is explained as follows:

- Figure 9-11 represents the total in-service capital and shows the identified ICM projects (excluding overheads).
- Figure 6-8 represents the annual cash flow of capital expenditure which includes required preliminary and post spend for ICM projects).[1]

[1] Exhibit C1, Tab 1, Schedule 1, page 50, footnote 11.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Vulnerable Energy Consumers Coalition (VECC)

Reference: Exhibit C1/T2/S1/ pgs. 694 – NPS 20 Don River Relocation & pgs.- pg.854 Service Relay

Preamble: The purpose of this interrogatory is to better understand the calculation and relative use of the Lifetime Risk Return on Investment Analysis

Question:

a) Please provide the actual calculation for the LRROI for these two projects. Specifically show how the variables "*Safety Risk Mit, Fin Risk Mit, CSAT Risk Mit*" are determined for each project.

b) The Don River Relocation project has an LRROI of 119. The Relays project has an LRROI of 24. In terms of the relative need between these two projects please explain how the LRROI informs the selection of the projects to be included (or excluded) in the capital plans of the Utility.

c) Do the capital projects considered in the Union Rate Zone go through the same LRROI process as those in the EGD rate zone?

Response

a) As per Exhibit C1, Tab 2, Schedule 1, page 89, LRROI is calculated using **Equation 1**:

$$\text{LRROI}=\frac{\text{Discounted Lifetime Risk Reduction}}{\text{Total Net Capital Investment}}$$

Equation 1: LRROI Calculation

The Discounted Lifetime Risk Reduction is calculated using **Equation 2**:

$$\text{Discounted Lifetime Risk Reduction} = (\text{Safety Risk Mit} \times \text{Useful Life}) + \left(\text{Fin Risk Mit} \times \frac{1-(1+\text{pretax WACC*})^{-\text{useful life}}}{\text{pretax WACC}}\right) + \left(\text{CSAT Risk Mit} \times \frac{1-(1+\text{pretax WACC})^{-\text{useful life}}}{\text{pretax WACC}}\right)$$

**WACC: Weighted Average Cost of Capital*

Equation 2: Discounted Lifetime Risk Reduction

The variables "Safety Risk Mit, Fin Risk Mit, CSAT Risk Mit" in **Equation 2** represent risk reductions for the three risk dimensions as described in Table 4.1.2.[1] Through the Quantitative Risk Assessment (QRA) process, risks were quantified for these dimensions in each project.[2] The consequence ratings that are used to assess the level of risk in each of these dimensions are presented in Table 4.1-3.[3]

Values for variables used **Equation 2** are provided below:

	Project #	
Variables	**10087 – NPS 20 Don River Relocation**	**16907 – Relay Blanket – All Areas**
Safety Risk Mit	36,230	34,216
Fin Risk Mit	2,413,116	299,811
CSAT Risk Mit	226,592	57,824
Useful Life (Years)	70	45
Pretax WACC	0.062147	0.062147

By applying the values in the above table to **Equation 2**, Discounted Lifetime Risk Reduction for both business cases are:

10087, NPS 20 Don River Relocation: 44,387,289
16907, Relay Blanket All Areas: 6,912,692

As Total Net Direct Capitals for NPS 20 Don River Relocation and Relay Blanket All Area are $35,872,742[4] and $28,252,443[5] respectively, according to **Equation 1**, LRROIs for both business cases are:

NPS 20 Don River Relocation (ID No. 10087): 124%
Relay Blanket All Areas (ID No. 16907): 24%

1 Exhibit C1, Tab 2, Schedule 1, page 72.
2 Ibid., pages 71, and pages 79 to 82.
3 Ibid., page 73.
4 Ibid., page 695.
5 Ibid., page 855.

For NPS 20 Don River Relocation, the slight discrepancy between the LRROI shown here versus the value published in Exhibit C1, Tab 2, Schedule 1, page 695 is due to a change in the Total Net Direct Capital at the time of the filing.

b) LRROI is a measure indicating the efficiency with which risk is reduced across all asset classes.[6] When the comparison is done solely on the basis of LRROI between the two selected projects, the Don River Relocation project has higher risk reduction efficiency than the Service Relay project. In addition to LRROI, other aspects are considered in the capital plans of the Utility; please refer to Figure 4.1-7: Risk Tolerance Framework and Table 4.1-4 Types of Risk.[7]

c) No, the Union rate zones use a more qualitative risk evaluation approach to facilitate a prioritization of their investments. This process is outlined at Exhibit C1, Tab 3, Schedule 1**,** pages 51 to 58.

[6] Ibid., page 89.
[7] Ibid., page 74.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Vulnerable Energy Consumers Coalition (VECC)

Reference: Exhibit D

Question:

a) Please provide the total cost of the customer engagement exercise for this application distinguishing between (1) contractor/consultant costs and (2) internal allocated – or tracked costs).

Response

a) The consultant costs of the customer engagement exercise for legacy EGD and Union are provided in Table 1. Neither company allocated or tracked other costs associated with the customer engagement exercises.

Table 1

Legacy Utility	Consultant Costs
EGD	$201,500 (excluding HST)
Union	$353,000 (excluding HST)