2018 OPERATING REVENUE SUMMARY

1. The purpose of this evidence is to present the 2018 Updated Revenue Forecast as compared to the 2017 Board Approved and 2018 Board Approved Placeholder revenue amounts.

2. Table 1 shows the respective 2017 Board Approved, 2018 Board Approved Placeholder, and 2018 Updated Forecasts by operating revenue component.

Table 1
COMPARISON OF UTILITY OPERATING REVENUE

Item No.		Col. 1 EB-2016-0215 2017 Board Approved ($Millions)	Col. 2 EB-2012-0459 2018 Board Approved (placeholder) ($Millions)	Col. 3 2018 Updated Forecast ($Millions)
1	Gas Sales	2,451.5	2,496.2	2,625.2
2	Transportation of Gas	288.3	205.0	251.8
3	Transmission, Compression and Storage (inc. Rate 332)	19.1	1.8	19.2
4	Other Revenue	42.7	42.7	42.7
5	Other Income	0.1	0.1	0.1
6	Total Operating Revenue	2,801.7	2,745.8	2,939.0

3. The 2018 Updated Revenue Forecast is $2,939.0 million as shown at Exhibit C3, Tab 1, Schedule 1. This represents a $193.2 million increase over the 2018 Placeholder of $2,745.8 million.

Witness: M. Suarez

4. The variance is explained by the revenue categories in the following paragraphs.

Gas Sales and Transportation of Gas Revenues

5. Gas sales and transportation of gas revenues for the 2018 Board Approved Placeholder used the Board-approved commodity rates in place in 2013 and the 2018 placeholder gas volume budget. Specifically, the 2018 Board Approved Placeholder was developed on the basis of EB-2013-0045 commodity rates set out in the April 2013 QRAM and the 2013 final rates that can be found in the Board Decision and Order for EB-2011-0354. The 2018 Updated Forecast Gas Sales and transportation of Gas Revenues are based on the EB-2017-0181 commodity rates set out in the July 2017 QRAM and the 2017 Final Rate Order in EB-2016-0215. Those updated commodity rates are applied to the updated gas volume forecast set out within this rate adjustment application.

6. The evidence in support of the Company's 2018 updated gas volume forecast is set out within Exhibit C1, Tab 2, Schedule 1 and the C2 series of exhibits, with further numeric details in the C3 series of exhibits.

7. The increase in gas sales and transportation of gas revenues of $175.8 million from the 2018 Board Approved Placeholder to the 2018 Updated Forecast is primarily due to higher volumes forecasted and higher rates in the 2018 Updated Forecast.

8. A breakdown of the 2018 Updated Forecast and 2018 Board Approved Placeholder gas sales and transportation of gas revenues by rate class is provided within the C3 series of exhibits.

Witness: M. Suarez

Transmission, Compression and Storage

9. Transmission, Compression and Storage revenues for the 2018 Updated Forecast are also developed on the basis of Final Rate Order in EB-2014-0276, resulting in a $17.4 million increase as compared to the 2018 Board Approved Placeholder. The increase is due to the implementation of Rate 332 in 2016.

Other Operating Revenues

10. Within the Board's EB-2012-0459 Decision with Reasons, Enbridge's Other Operating Revenues and Other Income were set at the level of $42.7 million and $0.1 million for each year from 2014 to 2018. Accordingly, there is no change in these amounts within the 2018 Updated Forecast.

GAS VOLUME BUDGET

1. The purpose of this evidence is to present the 2018 forecast of volumes to reflect updated forecast assumptions as part of the annual adjustments required for the 2018 Rates Adjustment proceeding. The evidence describes the forecasting methodology and the key assumptions used to develop the volumes forecast for General Service customers and Contract Market customers. The 2018 volume forecasts have been prepared based on the approved methodology applied in prior rate case applications, including the probability-weighted approach for potential new contract customers.

2. In addition, as agreed in the Settlement Proposal for EB-2017-0102 (Exhibit N1, Tab 1, Schedule 1, page 8), this evidence contains information about the establishment of baseload and heatload per customer within the description of weather normalization (page 12), as well as the derivation of customer counts (Appendix B). Enbridge confirms that no changes have been made to these methodologies since rebasing for the 2013 test year. And finally, additional tables showing the monthly breakdown of forecast volumes for Rates 1 and 6 including forecast baseload and heatload per customer and of customer meters are set out within Appendix A (Tables 5 and 6).

3. A summary of the 2018 volumes forecast is provided in the next page. Further rate class detail and explanation for all gas volumes and related items are provided at Exhibit C3, Tab 2, Schedule 3.

Table 1
Summary of Gas Sales and Transportation Volumes
(Volumes in 10^6m^3)

	2016 Actual	2017 Board-Approved Budget	2018 Budget
General Service Volumes	8 995.5	9 774.0	9 590.3
Contract Market Volumes	1 931.6	1 978.2	1 907.5
Total Volumes, Gas Sales and Transportation	10 927.1	11 752.2	11 497.8
Customers, Gas Sales and Transportation (Average)	2 124 683	2 153 924	2 183 043

4. Total customers are reported as the annual average of monthly customer numbers. This annual average customer methodology has been used to develop Board-Approved annual average customer numbers for more than ten years. Table 2 shows the annual average number of general service and contract market customers for the forecast year. The methodology used to develop the customer budget is described at Appendix B of this evidence.

Table 2
Summary of Total Average Number of Customers

	2016 Actual	2017 Board-Approved Budget	2018 Budget
General Service Customers	2 124 267	2 153 514	2 182 641
Contract Market Customers	416	410	402
Total Number of Customers (Average)	2 124 683	2 153 924	2 183 043

General Service Demand Forecast Methodology

5. The Rate 1 and Rate 6 General Service volume forecast is derived using the corresponding customer forecasts and the normalized average use per customer forecast generated from the average use forecasting models.

6. The average use forecasting models are regression models developed by the Company which are described at Exhibit C2, Tab 1, Schedule 3. The forecast incorporates economic assumptions from the Economic Outlook (Q1 2017) as shown at Exhibit C2, Tab 1, Schedule 1.

7. The major explanatory variables in the Rate 1 and Rate 6 models are heating degree days, vintage (Rate 1 only), employment, Ontario real gross domestic product, vacancy rates (Rate 6 only), real energy prices, and a time trend. The estimated impacts of Cap and Trade were factored into the average use volumetric forecasts and the methodology for incorporating this impact into the average use forecasts is further described in Appendix C of this evidence.

8. Annual econometric models are employed to model and quantify the impact of different variables on average use per customer. The vintage variable is constructed to reflect the impact that new homes, which are associated with more energy efficient gas equipment and enhanced building codes, have on average use. The time trend, along with the dynamic variable in the regression model, captures the historical actual average trend, conservation initiatives pursued by customers themselves or promoted by government programs, stock turnover, and other historical impacts not reflected in the aforementioned driver variables.

9. The forecast of average use per customer is generated based on weather-normalized volumes data. Normalization is the process that allows the Company to compare average use per customer absent any variations due to weather. The Company's weather normalization methodology has been approved by the Board and utilized for more than twenty-five years. The establishment of baseload and heatload volumes are described within the Weather Normalization section of this exhibit (pp 12 to 14), and further detailed in Tables 5 and 6 of Appendix A.

10. Consistent with previous rate cases, the Company continues to report the results that the models would have generated using the actual data for driver variables to compare results to the prior year's forecast. Rate 1 average in-sample forecast error using the regression models is 0.5%, and Rate 6 average in-sample forecast error is -0.3% over the last 10 years[1]. Overall, the regression model continues to be a reliable predictor of General Service average use.

[1] Please see Exhibit C2 Tab 1 Schedule 3, Tables 2 and 3 for other reported forecast errors. Average variance is shown for Rate 1 and Rate 6 in column 8 of both tables, respectively.

11. Regression model results for Rate 1 and Rate 6 are adjusted for planned DSM in the test year through partially-effective volumetric savings by program. Although the models utilize historical data that already include historical DSM, a prospective adjustment is needed for new programs introduced in the test year. The 2018 partially-effective DSM adjustments by rate class and service type are shown at column 10 of Exhibit C3 Tab 2 Schedule 3, page 3.

12. Enbridge is expected to have no NGV (Rate 9) customers in 2018. The primary reason for the steady decline in NGV customers from 2006 is the decrease in NGV production and sales as vehicle manufacturers shift production to meet demand for electric, hybrid and gasoline vehicles, particularly for the light-duty and the medium segments.

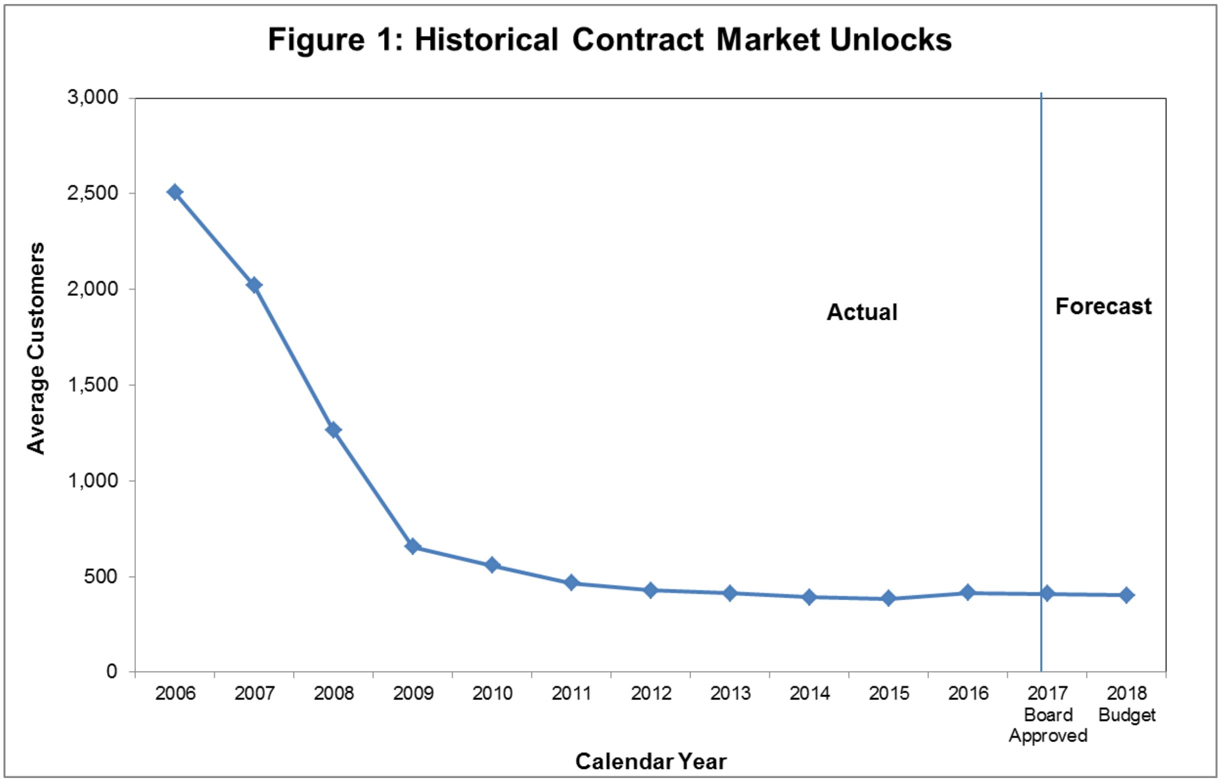
<u>Contract Market Volume Forecast Methodology</u>

13. The Contract Market volume budget was generated using the established grassroots approach as well as the probability-weighted forecast approach for potential, new large-volume contract customers.

14. At any given point in time, Enbridge is in conversation with new and existing customers to evaluate their gas service requirements. The traditional grassroots approach arrives at volume forecasts at the individual customer level through consultation between Account Executives (“AE”s) and customers during the budget process. Specifically, the AEs review the contract attributes of each contract to ensure that customers can meet the contracted rate class minimum volume and load factor requirements. Current economic and industry conditions as well as budgeted degree days and DSM are factored into the budget determination. The same approach has been retained to forecast volumes for existing customers.

15. For the purpose of establishing a probability-weighted methodology for potential customers, existing practices were leveraged. Over the years, as the AEs in the Key Accounts group have worked with numerous potential customers, they collectively devised a system of capturing the stages at which new customers progress from the initial evaluation stage to signing a Large Volume Distribution Contract. Five stages or buckets are used to funnel projects from initial discussions through to energizing the pipeline. The probabilities or weights for each stage were assigned through conversations with the AEs who drew on actual experiences over the years, and were applied to the volumes that were forecast to be effective in the forecast year. For more details on the approach, please refer to EB-2014-0276 Exhibit C1, Tab 2, Schedule 1.

16. Based on the combined grassroots and probability-weighted approaches, Figure 1 below shows the Contract Market unlocks forecast for 2018, the 2017 Board-Approved unlocks, as well as historical actual Contract Market unlocks from the last 11 years.



17. Approximately 2,000 Contract Market customers migrated to General Service over the period 2006 through 2010. This customer migration drove up average use per customer in Rate 6 over that period. With rate migration stabilizing in recent years, the number of projected Contract Market customers follows a relatively flat trend.

18. As a consequence of the implementation of the Natural Gas Electricity Interface Review ("NGEIR") in 2007, the Company experienced customer migration from bundled rate classes that bill distribution volumes volumetrically, reported in Table 1, to unbundled rate classes (e.g., Rate 125, Rate 300 Firm) that do not bill distribution volumes volumetrically. Unbundled customers incur monthly contract demand charges on contract volumes and generate fixed contract demand revenues. The 2018 contract demand volumes are expected to decline by

8.1 10^6m^3 compared to the 2017 Board Approved Budget due to a power generation customer (Rate 125) forecast to migrate to General Service. Table 3 below presents a summary of these contract demand volumes.

Table 3
Summary of Unbundled Customers Contract Demand Volumes
(Volumes in 10^6m^3)

	2016 Actual	2017 Board-Approved Budget	2018 Budget
Total Contract Demand Volumes	119.4	119.4	111.3

2018 Volume Budget

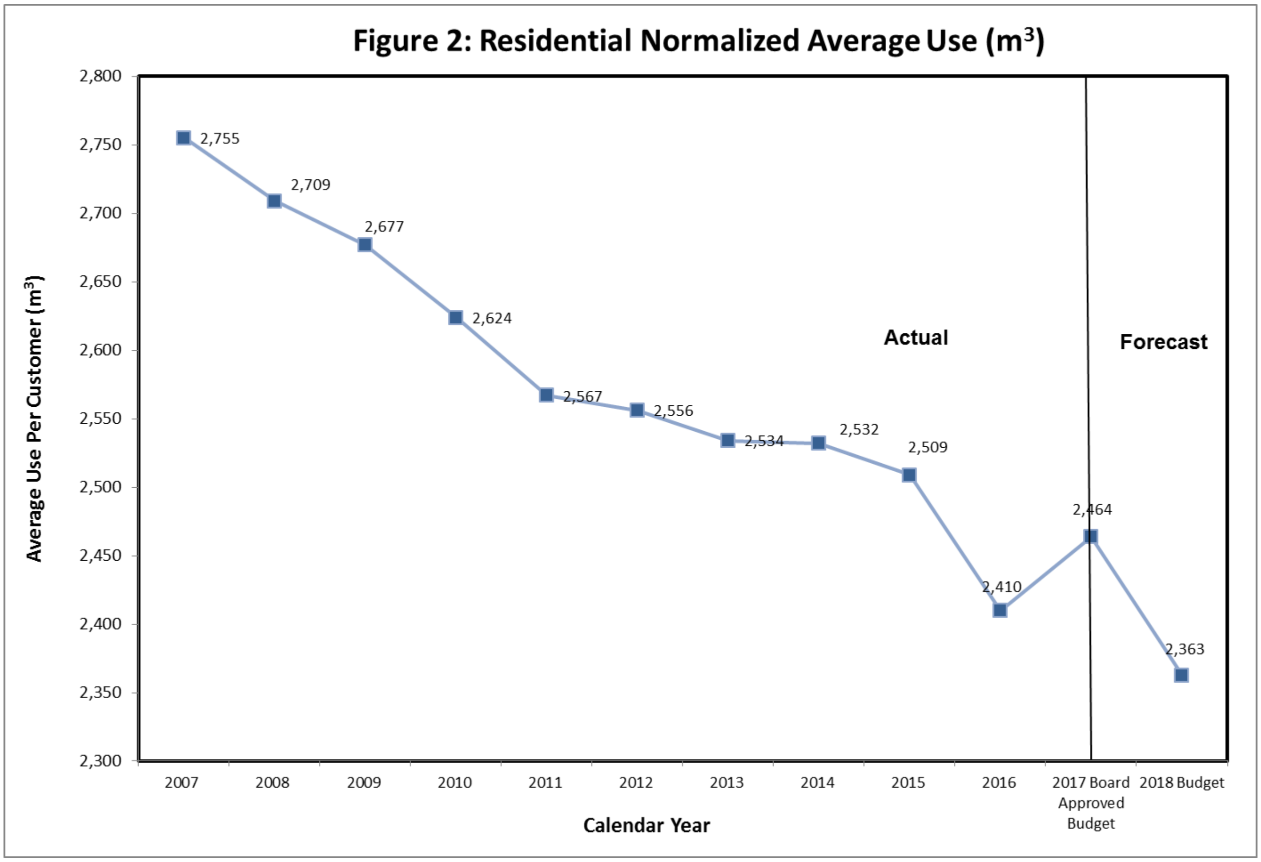
19. Budget volumes are derived by incorporating heating degree day forecasts, average use forecasts, customer unlocks forecasts, as well as grassroots and probability-weighted contract market forecasts. The 2018 Budget volumes reflect the meter reading heating degree days forecast generated using approved degree day methodologies in the EB-2012-0459 Decision. The 2018 Budget is comprised of General Service volumes of 9,590.3 10^6m^3 and Contract Market volumes of 1,907.5 10^6m^3. A detailed breakdown of gas volumes by rate class is provided at Exhibit C3, Tab 2, Schedule 1. Monthly meter reading heating degree days are determined by combining the Gas Supply heating degree day forecasts with the billing schedules. Please refer to Exhibit C2, Tab 1, Schedule 2 for a detailed explanation of the derivation of the Company's 2018 heating degree day forecast.

20. Residential average use per customer has declined steadily over the period of 2007 through 2015, at an average rate of 1.1% per year. The rate of actual

average use decline in 2016 was an anomaly as it was not consistent with the historical trend, declining from 2015 by -3.2%. No significant development occurred in 2016 that would allow direct causal inference with 2016 results. As a result, the Company is inclined to treat the 2016 experience as an anomaly until additional, similar actual observations constitute an indication of trend. This treatment is confirmed through diagnostic testing of econometric models as further detailed in the Average Use Evidence at Exhibit C2 Tab 1 Schedule 3 on page 7. If a structural break is indicated, dummy variables are included in the model to suppress the likelihood of a similar off-trend result being forecast.

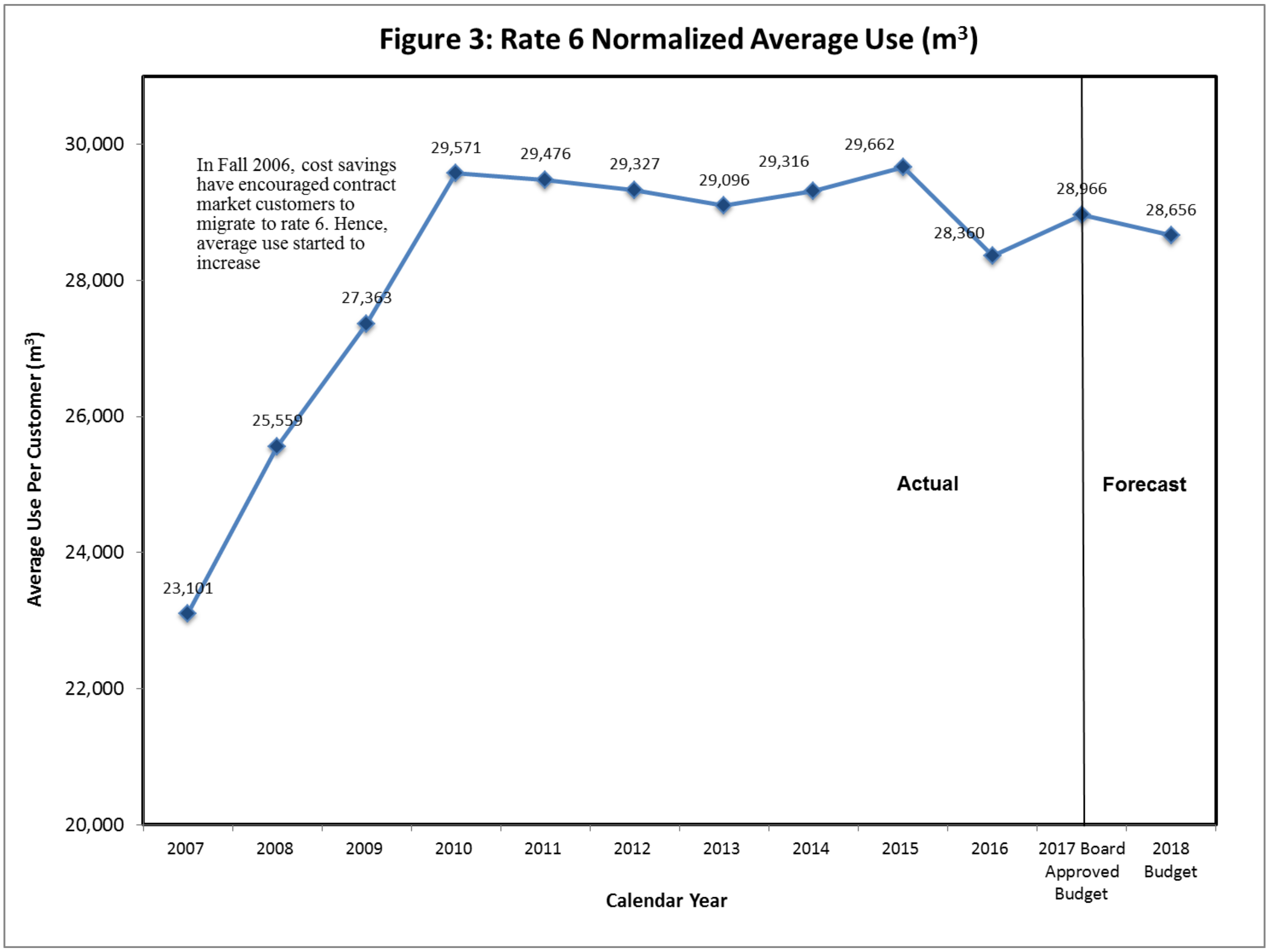
21. Appendix A of this evidence shows historical normalized actual and Board-Approved General Service average uses normalized to each year's respective Budget degree days (Table 1), or to 2018 Forecast degree days (Tables 2 and 3) to eliminate varying weather impacts and facilitate year-over-year comparison. In addition, and as part of the Settlement Agreement in EB-2017-0102, Enbridge is providing Tables 5 and 6 which show the monthly distribution of average use, separated into heatload, and baseload for the forecast year.

22. Figure 2 depicts historical actual average use normalized to constant degree days at the 2018 forecast level (values from Table 2 in Appendix A) to isolate the impact of weather year over year.



23. The current 2018 forecast which incorporates the latest actual data up to 2016, calls for a continuation of the declining trend for Rate 1 average use per customer.

24. Figure 3 on the following page shows the normalized actual average use per customer for Rate 6 from 2007 to 2016 as well as the projections for 2017 to 2018 as shown at Table 2 and Table 3 of Appendix A.



25. As noted earlier, customer migration from Contract Market to General Service has resulted in a significant increase in Rate 6 usage per customer particularly from 2007 to 2010. Rate design changes which became effective April 2007 prompted much of this rate migration.

26. Over the more recent years, rate migration has stabilized and Rate 6 average use per customer has reflected a relatively flat trend. Like Rate 1 average use in 2016, Rate 6 average use saw a similar off-trend result. It is expected that Rate 6

average use per customer will decrease slightly in 2018 compared to 2017 Board Approved Budget after incorporating the lower 2016 actual usage into the sample.

Comparison of Volumes: 2018 Budget versus 2017 Board Approved Budget

27. The 2018 Budget volumes reflect the regional heating degree day forecasts as shown at Exhibit C2, Tab 1, Schedule 2. The 2018 degree day forecasts for Central, Eastern and Niagara regions are 3,642, 4,331 and 3,421 respectively. The forecast for Central region has a slight increase of 3 degree days compared to the 2017 Board Approved Budget level of 3,639.

28. As shown at Exhibit C3, Tab 2, Schedule 3, page 1, the 2018 Budget volumetric forecast of 11 497.8 10^6m^3 is 254.4 10^6m^3, or 2.2%, below the 2017 Board-Approved Budget of 11 752.2 10^6m^3. The decrease is primarily attributable to lower average use per customer in general service volumes. On a weather-normalized basis, the 2018 Budget volumes are forecast to be 221.9 10^6m^3 lower than the 2017 Budget as shown at Exhibit C3, Tab 2, Schedule 3, page 2. The volumetric decrease on a normalized basis is made up of decreases in General Service volumes of 151.3 10^6m^3 and in the Contract Market of 70.6 10^6m^3. The following paragraphs describe contributing factors to these volumetric changes.

29. Page 3 of Exhibit C3, Tab 2, Schedule 3 shows that the decrease in General Service volumes of 151.3 10^6m^3, on a weather-normalized basis, is primarily due to lower average use per customer in Rate 1 and Rate 6 totaling 263.9 10^6m^3, partially offset by the net customer growth of 90.0 10^6m^3 (combined impact of new customers and lost customers) and net customer migration from Contract rates of 22.6 10^6m^3 (net transfers).

30. The 2018 Contract volume budget is expected to see a decrease of 70.6 10^6m^3 compared to the 2017 Budget on a weather-normalized basis. The variance is mainly due to net customer migration of 22.6 10^6m^3 to General Service and net customer loss of 48.2 10^6m^3.

<u>Evaluation of Forecast Accuracy – Historical Normalized Actual vs. Board Approved Budget</u>

31. The key factor used to evaluate the accuracy of the General Service volumes forecast is the percentage variance between normalized actual and normalized forecast average use per customer. Table 1 at Appendix A of this evidence provides the 10-Year history of Normalized Actual vs. Board-Approved volumes, where the out-of-sample average normalized percentage variance over the last 10 years is -0.4% for Rate 1 and 1.2% 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.

32. For the Contract Market, customer migration has had a significant impact on forecast accuracy over the period from 2007 and 2010. In addition, Contract Market volumes are primarily driven by economic factors which, during that period, were particularly volatile. Table 4 at Appendix A of this evidence shows the10-Year history of Normalized Actual vs. Board Approved volumes for Contract Market customers to evaluate the accuracy of the forecast volumes. Over the last 10 years, the average normalized percentage variance for contract customers is 0.04%. Of note, the variance is larger in the first four years than the latter half as migration has tapered off.

Weather Normalization Methodology

33. The Company's weather normalization methodology was approved by the Board in EBRO 465 and subsequently refined with the segregation of baseload and weather-sensitive loads in EBRO 473. The combined approach has been utilized for over twenty-five years. Consistent with previous rate cases, this section explains the Board-Approved normalization methodology of eliminating the impact of weather when reporting actual consumption for all rate classes. It further explains how baseload and heatload volumes are derived as it is only the heatload portion of consumption that is subject to normalization.

34. General Service normalization is carried out at the revenue class level to homogenize gas usage within Rates 1 and 6 for six operating regions within three weather zones in the franchise. The heat sensitive portion of consumption is isolated for each combination of revenue class-region-weather zone ("grouping") using balance point degree days, measured to the specific weather sensitivities within those areas. Balance point degree days were first introduced in EBO 487 following observations from heating load analysis that weather-sensitive loads started to increase at temperatures below the traditional 18ºC. The usage of balance point degree days was approved and subsequently applied in normalization and average use forecasting to more closely estimate the weather impact on consumption. The use of balance point degree does not impact the Company's degree day forecast but rather recalibrates the approved Environment Canada and Gas Supply degree days for load forecasting purposes from the traditional 18-degree-day threshold to the following balance points for each of the regions:

	Central	Eastern	Niagara
Balance Point	14.8ºC	14.6ºC	15.3ºC

35. Heatload is isolated monthly by first removing baseload, which represents non-weather-sensitive load such as water heating. Summer baseload is calculated as the average total consumption in July and August. For all other months, baseload is profiled to recognize the seasonal aspect of baseload demand due to a blended combination of appliance mix and ambient temperature as determined through successive load research studies. The seasonality factors have remained constant since 2014 and are calculated relative to the summer baseload.

36. Once heatload is isolated for each grouping, total load per customer of a particular customer grouping is calculated by dividing the group's monthly forecast consumption by the total monthly customers within the group to derive a representative average load. This heatload represents the heat-sensitive portion of consumption that is adjusted for normalized consumption. Weather adjustments are calculated in two steps: by (1) deriving Actual Use per actual heating degree day (heatload per customer divided by Actual Heating Degree Days); (2) multiplying actual use per degree day derived in step (1) to the variance between actual and budget heating degree days. This method provides a simple way to preserve the underlying actual average use expressed against the expected weather, thereby removing any weather variability. Consequently, total normalized average use per customer is defined as the sum of baseload use per customer and normalized heatload per customer. The monthly forecast volumes data for Rate 1 listed in Table 5 at Appendix A aggregates the individual volumes forecasts for all Rate 1 revenue classes (revenue classes 10, 20, 50, 60 and 61). Similarly, Table 6 in the same appendix shows the aggregated volumes for all Rate 6 revenue classes (revenue classes 12, 48, 73, 79, 83, 86 and 90).

37. For Contract Market customers, a similar process is followed to determine the actual baseload for each contract. Actual heatload is obtained by removing baseload and process load from total consumption, which is then adjusted to reflect normal weather. The actual volumes are also adjusted, where necessary, to the budgeted level of curtailment.

GENERAL SERVICE AVERAGE USES
HISTORICAL NORMALIZED ACTUAL AND BOARD APPROVED

1. To facilitate the comparison of average uses between Actual and Board Approved values, as well as observe year-over-year trends, it is essential to normalize the weather impact by removing the variation in demand that is caused by weather. The series of tables in this appendix provides historical comparisons of average use volumes for the General Service and Contract Market classes.

2. Tables 1 to 3 show normalized General Service average uses, and Table 4 shows normalized total contract volumes. Actual average uses in Table 1 on page 2 have been normalized to the corresponding Board Approved degree days for the respective year. In contrast, the normalized average uses in Tables 2 and 3 are presented on a calendar-year basis where each year has been normalized to the 2018 forecast degree days. The latter presentation is used to consistently eliminate weather variations across years. In Table 4, the total contract volumes have been normalized to the corresponding Board Approved degree days for each of the respective years.

3. Additionally, as agreed in the Settlement Proposal in Enbridge's 2016 Earning Sharing Mechanism, EB-2017-0102, Tables 5 and 6 have been added to provide a monthly breakdown of the 2018 volumetric forecast, average use per Rate 1 and Rate 6 customer (also broken out between baseload and heatload), and customer meter forecasts (unlocks).

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
2007	Rate 1	2,726	2,687	39	1.5%
	Rate 6	22,783	21,010	1,773	8.4%
	Total General Service	4,412	4,200	212	5.0%
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	29,878	29,878	(0)	0.0%
	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%

Witness: M. Suarez

TABLE 2
GENERAL SERVICE
SYSTEM-WIDE TOTAL NORMALIZED AVERAGE USE*

		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 10	Col. 11	Col. 12
		2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017 Board-Approved Budget	2018 Forecast
Residential		2,755	2,709	2,677	2,624	2,567	2,556	2,534	2,532	2,509	2,410	2,464	2,363
	Change		(46)	(32)	(53)	(57)	(11)	(22)	(2)	(23)	(99)	54	(101)
	% Change		-1.67%	-1.18%	-1.98%	-2.17%	-0.43%	-0.86%	-0.08%	-0.91%	-3.95%	2.24%	-4.10%
Apartment		103,014	127,392	144,974	164,686	152,591	149,384	149,420	152,493	151,422	145,249	150,031	147,130
	Change		24,378	17,582	19,712	(12,095)	(3,207)	36	3,073	(1,071)	(6,173)	4,782	(2,901)
	% Change		23.66%	13.80%	13.60%	-7.34%	-2.10%	0.02%	2.06%	-0.70%	-4.08%	3.29%	-1.93%
Commercial		17,726	18,426	19,069	19,740	19,863	20,014	19,785	19,837	20,388	19,428	19,794	19,627
	Change		700	643	671	123	151	(229)	52	551	(960)	366	(167)
	% Change		3.95%	3.49%	3.52%	0.62%	0.76%	-1.14%	0.26%	2.78%	-4.71%	1.88%	-0.84%
Industrial		61,171	75,685	89,209	108,231	109,202	106,688	108,256	111,396	111,219	109,863	113,360	116,354
	Change		14,514	13,524	19,022	971	(2,514)	1,568	3,140	(177)	(1,356)	3,497	2,994
	% Change		23.73%	17.87%	21.32%	0.90%	-2.30%	1.47%	2.90%	-0.16%	-1.22%	3.18%	2.64%

* All historical average uses are on a calendar-year basis and have been normalized to the 2018 Budget degree days.

TABLE 3
GENERAL SERVICE
SYSTEM-WIDE TOTAL NORMALIZED AVERAGE USE*

		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 10	Col. 11	Col. 12
		2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017 Board-Approved Budget	2018 Forecast
Rate 1		2,755	2,709	2,677	2,624	2,567	2,556	2,534	2,532	2,509	2,410	2,464	2,363
	Change		(46)	(32)	(53)	(57)	(11)	(22)	(2)	(23)	(99)	54	(101)
	% Change		-1.67%	-1.18%	-1.98%	-2.17%	-0.43%	-0.86%	-0.08%	-0.91%	-3.95%	2.24%	-4.10%
Rate 6		23,101	25,559	27,363	29,571	29,476	29,327	29,096	29,316	29,662	28,360	28,966	28,656
	Change		2,458	1,804	2,208	(95)	(149)	(231)	220	346	(1,302)	606	(310)
	% Change		10.64%	7.06%	8.07%	-0.32%	-0.51%	-0.79%	0.76%	1.18%	-4.39%	2.14%	-1.07%

* All historical average uses are on a calendar-year basis and have been normalized to the 2018 Budget degree days.

TABLE 4

CONTRACT CUSTOMERS' TOTAL NORMALIZED VOLUME

	Col. 1	Col. 2	Col. 3	Col. 4
Test Year	Actual Normalized Consumption (10^6m^3)	Board-Approved Normalized Consumption (10^6m^3)	Variance Normalized Consumption (1-2)	%Variance Normalized Consumption (3/2)*100
2007	3,739.8	4,134.3	(394.5)	-9.5%
2008	3,099.6	3,355.2	(255.6)	-7.6%
2009	2,191.4	2,316.6	(125.2)	-5.4%
2010	2,191.5	2,008.6	182.9	9.1%
2011	2,081.8	2,022.9	58.9	2.9%
2012	2,072.6	1,943.4	129.2	6.6%
2013	2,022.7	1,945.5	77.2	4.0%
2014	1,923.6	1,967.0	(43.4)	-2.2%
2015	1,913.5	1,916.2	(2.7)	-0.1%
2016	1,935.1	1,899.8	35.3	1.9%

Witness: M. Suarez

TABLE 5
GENERAL SERVICE RATE 1
2018 BUDGET - VOLUME, CUSTOMERS & AVERAGE USE

		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 10	Col. 11	Col. 12	Col. 13	
Item.		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total	Exhibit Reference
1.1	Budget Volumes ($10^6 m^3$)	803.3	825.5	716.3	521.9	286.8	146.6	112.8	108.3	108.5	173.1	367.5	589.9	4,760.5	Exhibit C3, Tab 2, Schedule 1
1.2	Customer Meters Budget	2,007,006	2,009,216	2,011,243	2,012,841	2,012,650	2,011,270	2,010,569	2,012,498	2,014,584	2,020,929	2,026,670	2,031,442	2,015,077	
1.3	Budget Average Use per Customer (m^3)	400	411	356	259	143	73	56	54	54	86	181	290	2,363	Row 1.1 / Row 1.2
1.4	Baseload Average Use per Customer (m^3)	68	68	71	67	65	65	56	54	54	56	62	65	751	
1.5	Heatload Average Use per Customer (m^3)	332	343	285	193	78	7	0	0	0	30	119	225	1,612	

TABLE 6
GENERAL SERVICE RATE 6
2018 BUDGET - VOLUME, CUSTOMERS & AVERAGE USE

		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 10	Col. 11	Col. 12	Col. 13	
Item.		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total	Exhibit Reference
1.1	Budget Volumes (10^6m^3)	729.4	870.0	740.9	540.7	316.6	155.8	110.8	107.7	108.6	177.2	385.5	586.5	4,829.8	
1.2	Customer Meters Budget	168,893	169,139	169,371	169,049	168,348	166,578	165,889	165,044	164,861	166,287	168,153	169,158	167,564	Exhibit C3, Tab 2, Schedule 1
1.3	Budget Average Use per Customer (m^3)	4,319	5,144	4,374	3,198	1,881	935	668	652	659	1,066	2,293	3,467	28,656	Row 1.1 / Row 1.2
1.4	Baseload Average Use per Customer (m^3)	1,145	1,271	1,171	979	910	841	668	652	659	666	920	1,078	10,959	
1.5	Heatload Average Use per Customer (m^3)	3,174	3,873	3,203	2,220	971	94	0	0	0	400	1,373	2,389	17,697	

AVERAGE NUMBER OF CUSTOMERS

1. The purpose of this exhibit is to present the forecast of the annual average number of customers underpinning the 2018 volume budget. The annual average customer methodology has been used by Enbridge to calculate forecast customer numbers for more than ten years.

2. The 2018 Customer Budget of 2,183,043 is forecast to be 29,119, or 1.4%, above the 2017 Board Approved Budget of 2,153,924. A detailed breakdown of the number of customers by rate class is provided at Exhibit C3, Tab 2, Schedule 2. The increase in customers is primarily attributable to the customer additions in the 2018 Budget. Total customer additions are forecast at 30,449 for 2018. The customer additions forecast underpins the new customer volumes forecast of 90.3 10^6m^3 in the 2018 Budget relative to the 2017 Budget in the General Service market as shown at Exhibit C3, Tab 2, Schedule 3 (page 3, column 6).

Underlying Forecast Methodology

3. Consistent with previous rate proceedings, each year's customer count is reported as the annual average of monthly customer numbers. Every month, customer numbers are determined by the number of active meters (or unlock meters)[1]. As a result, each month's customer number is an aggregate sum of the total active meters for that particular month. Specifically, each year's annual average is calculated as follows:

[1] An unlock meter is counted as a customer whose gas meter is unlocked, allowing gas to flow through the meter to a premise.

Annual Average_Customers = (1/12)(January_active_meters + February_active_meters + March_active_meters + April_ active_meters + May_ active_meters + June_ active_meters + July_ active_meters + August_ active_meters + September_ active_meters + October_ active_meters + November_ active_meters + December_ active_meters)*

4. Consistent with the contract demand forecast methodology discussed in the Gas Volume Budget evidence, contract customer counts in the contract market are generated through the grassroots forecasting approach between account executives and customers (including the probability-weighted methodology for potential new customers). The approach for forecasting the total number of contract market customers is represented below:

forecast contract market customers = year end customers
+ forecast new customer additions
+ forecast replacement customer additions
- forecast lost customers
+ forecast transfer gains (i.e., customer migration from general service Rate 6 to contract market rate class)
– forecast transfer losses (i.e., customer migration from contract market rate class to general service Rate 6)

5. In the most simplistic sense, general service customers are forecast as follows:

General Service customers = year-end customers
+ forecast new customers
– forecast locked customers
+/- forecast gains or losses.

However, due to lags inherent in moving a customer addition to an unlocked customer, as well as variability in the timing of locked customers, lags impact the final number of unlocked customers. Regression analysis is used to enhance the objectivity of the forecast by leveraging model results using actual monthly data to predict the lags and the pattern of locked meters. Transfer gains or losses between contract rate class and general service Rate 6 continue to be obtained from account executives, and are layered onto the forecast general service Rate 6 customers.

6. There is always a time lag between when the service line is installed (that underpins capital expenditures and customer additions) and the first flow of gas which occurs when the customer moves into the premise and calls to have their meter unlocked by field staff. Only then does gas service commence and the customer's account (that underpins billed revenues and volumes) is activated. This time lag is challenging to predict. The Company has developed objective models to enhance the forecast process by estimating historical lags and considering these results as part of its forecast of unlocks.

7. Lock meters are defined as customers whose gas meters are locked and no gas is flowing through the meter to a premise. This can result from vacant premises (e.g., new construction, move-in/move out, bankruptcies, etc.), customers switching off gas to an alternate energy source, payment or credit reasons and seasonal usage. Unfavorable economic conditions (e.g., vacancy or bankruptcy) may lead to an increase in locked meters and this factor has been incorporated into the models considered as part of the customer forecast.

8. The 2018 Customer forecast was informed by the cumulation of the latest actual number of customers from 2016, expectations of year-end 2017 customer

additions, 2018 forecast of housing starts, and the ensuing 2018 forecast of customer additions. As shown at Table 2, the 2016 Total Actual Customer count was 5,754 lower than the 2016 Board-Approved Budget of 2,130,437. The

decrease is primarily due to lower customer additions in 2016 as shown at Table 1 below. These contributing factors were taken into account in the development of the 2017 Customer Budget.

Table 1 - Comparison of Customer Additions

2016 Customer Additions		
Actual	Board-Approved Budget	Variance
29,991	35,592	(5,601)

9. Monthly forecasts of customer unlocks were informed by historical monthly profiles as well as the lagged results from when customer additions become unlocks and when seasonal customers interrupt and subsequently resume service. The monthly forecast of customers is shown at Exhibit C1, Tab 2, Schedule 1, Appendix A, in Tables 5 and 6.

Evaluation of Forecast Accuracy – Historical Actual vs. Board Approved Budget

10. Historical Board Approved customer numbers are set out in Table 2. The information for periods prior to 2006 reflects a fiscal year-end of September 30th, whereas the years starting from 2006 are calendar years.

11. Table 2 on the following page shows Historical Actual vs. Board Approved customer numbers. The average percentage variance between actual customer

numbers and forecast customer numbers over the period shown is approximately 0.05%.

Table 2 - General Service and Contract Market Customers

	Test Year	Col. 1 Actual Customers	Col. 2 Board-Approved Customers	Col. 3 Variance Customers (1-2)	Col. 4 %Variance Customers (3/2)*100
FISCAL YEAR	1996	1,263,290	1,262,815	475	0.0%
	1997	1,312,434	1,309,752	2,682	0.2%
	1998	1,364,350	1,353,178	11,172	0.8%
	1999	1,414,788	1,417,832	(3,044)	-0.2%
	2000[a]	1,464,738	1,468,915	(4,177)	-0.3%
	2001	1,519,039	1,514,710	4,329	0.3%
	2002	1,566,710	1,565,017	1,693	0.1%
	2003	1,622,016	1,615,037	6,979	0.4%
	2004*	1,676,380	1,672,586	3,794	0.2%
	2005[b]	1,724,716	1,718,766	5,950	0.3%
CALENDAR YEAR	2006	1,782,813	1,792,615	(9,802)	-0.5%
	2007	1,824,789	1,823,258	1,531	0.1%
	2008	1,865,020	1,864,047	973	0.1%
	2009	1,887,605	1,906,437	(18,832)	-1.0%
	2010	1,926,294	1,931,528	(5,234)	-0.3%
	2011	1,960,378	1,965,538	(5,160)	-0.3%
	2012	1,994,903	1,984,734	10,169	0.5%
	2013	2,030,001	2,025,462	4,539	0.2%
	2014	2,063,837	2,059,619	4,218	0.2%
	2015	2,094,681	2,098,952	(4,271)	-0.2%
	2016	2,124,683	2,130,437	(5,754)	-0.3%

* 2004 Bridge Year Estimate from RP-2003-0203 was reported at column 2 because Board Approved numbers are not available since there was no 2004 Board Approved Volumes Budget due to the nature of the 2004 Rate Application. Please see RP-2003-0048, Exhibit A, Tab 3, Schedule 1 for the rationale for implementing this new approach.

CAP AND TRADE IMPACT ON 2018 VOLUME FORECAST

1. In the Board approved Settlement Proposal for EB-2016-0215 (2016 Rate Adjustment) Enbridge committed, as part of the 2018 Rate application, to:

> *…..present evidence addressing the impact on its gas volume forecasting methodology and (as applicable) it 2018 volumes forecast (including the Average Use True Up Variance Account (AUTUVA)), of the Ontario Government's climate change policies and associated Cap and Trade framework*.[1]

2. This evidence discusses Enbridge's Board-approved volumetric forecasting methodologies and describes how the Company has leveraged those methodologies to accommodate Cap and Trade price impacts in 2018. The evidence will further quantify the resulting volumetric impacts of Cap and Trade estimated by Enbridge as embedded within 2018 Rate 1 and Rate 6 average use forecasts.

Background

3. Enbridge's annual volume forecast is carried out through Board-approved methodologies that utilize econometric models for General Service (Rate 1 and Rate 6) volumes, and grassroots forecasts for Contract Market customers. See Exhibit C1, Tab 2, Schedule 1 for a full description of the overall approach.

4. The econometric models have been utilized by the Company since 1999 as an effective way to remove subjective bias in the average use forecasts by relying on well specified models and driver variables for forecasting. Over the years, the models have proven to be very accurate, with an average in-sample error of 0.12% for Rate 1 and -0.16% for Rate 6. See Exhibit C2, Tab 1, Schedule 3 Tables 2 and 3 for details on the Average Use Forecasting Models.

[1] EB-2016-0215, Ontario Energy Board, Decision and Rate Order, Schedule 1, page 7.

5. Grassroots forecasts for contract customers are obtained through direct communication with existing large volume customers. Historical trends, weather projections, general economic conditions, and specific industry factors are considered when deriving the year-ahead forecast. For potential new customers who may elect to obtain service in the budget year, Enbridge employs a probability-weighted approach which is applied to ongoing projects based on their stage within the process. The forecast error for contract volumes has remained at or below 4% for the last few years. See Exhibit C1, Tab, Schedule 1 Appendix A, page 5 for details.

Developing the 2018 Volume Forecast

6. The Company applied the Board-approved methodologies in developing the 2018 volume forecast. The impact of Cap and Trade was captured within the regression models through the gas price variable as an addition to the commodity, transportation, load balancing, and distribution components of Rate 1 gas prices and Rate 6 gas prices. In the OEB Report "*Regulatory Framework for the Assessment of Costs of Natural Gas Utilities' Cap and Trade Activities*" issued September 26, 2016, the Board determined that costs associated with customer-related obligations and facility-related obligations shall be included within the delivery charge on customer's bills. From a price signal perspective, customers will not be able to distinguish among the components contributing to the price change. Resulting behavioral impacts from the addition of Cap and Trade obligations will not be distinct from the behavioral impacts from a higher commodity price when modelled in this manner.

7. The double-log regression model specification allows for the use of the estimated price coefficient to be interpreted as the price elasticity of demand. It is the

percentage change in volumetric consumption associated with a 1% change in price. Enbridge's average use regression models estimate an average price elasticity of demand of -0.04% for Rate 1 customers, and -0.05% for Rate 6 customers for every 1% change in price.

8. Cap and Trade obligations contribute to an incremental 9.8% to Rate 1 gas prices and 12.5% to Rate 6 gas prices. Using the estimated elasticities set out in the previous paragraph, the impact of Cap and Trade costs is an incremental decrease in projected average use of 9 m^3 per Rate 1 customer, and a decrease in projected average use of 174 m^3 per Rate 6 customer.

9. Because the price change is evident as a single price signal for customers, the impact on demand cannot be broken out into its potentially distinct impacts as it is not perceived separately. As a result, the impact on demand of Cap and Trade costs has to be assumed to have the same impact as a regular price change. No other intrinsic signal can be inferred.

10. The resulting average use is a combined result of these price effects in addition to the other driver variables. While these impacts can be demonstrated from a forecast perspective, the same cannot be said of actual results. As a result, Cap and Trade impacts will remain included in Average Use results for purposes of the AUTUVA.

11. For 2018 Contract Market forecasts, Account Executives have engaged large volume customers in assessing their individual participation in Cap and Trade as well as how they may be pursuing abatement that would result in operational changes. The resulting grassroots forecast includes large volume customers' considerations of the impact of Cap and Trade.

Witness: M. Suarez

KEY ECONOMIC ASSUMPTIONS

ECONOMIC OUTLOOK: CANADA & U.S.*

CALENDAR YEAR	2012	2013	2014	2015	2016	2017F	2018F
REAL GDP (% CHANGE)							
CANADA	1.6	2.3	2.6	0.8	1.4	1.9	1.9
U.S.	2.2	1.7	2.4	2.6	1.6	2.3	2.3
CANADA REAL EXPORTS (% CHANGE)	2.9	2.0	5.3	3.6	1.4	2.4	3.3
CANADA REAL IMPORTS (% CHANGE)	4.2	1.9	2.0	1.0	-0.9	2.0	2.7
CANADA HOUSING STARTS (000's)	214.8	187.9	189.3	195.5	197.9	181.6	177.5
CANADA UNEMPLOYMENT RATE (%)	7.4	7.1	6.9	6.9	7.0	6.9	6.8
CANADA EMPLOYMENT GROWTH (% CHANGE)	1.4	1.3	0.6	0.8	0.7	0.9	0.8
CONSUMER PRICES (% CHANGE)							
CANADA	1.6	0.9	1.9	1.1	1.4	2.1	2.1
U.S.	2.1	1.5	1.6	0.1	1.3	2.4	2.4

* The forecasts have been updated to reflect the Q1 2017 Economic Outlook.

ECONOMIC OUTLOOK: ONTARIO*

CALENDAR YEAR	2012	2013	2014	2015	2016	2017F	2018F
REAL GDP (% CHANGE)	1.3	1.5	2.7	2.5	2.6	2.2	2.1
REAL MANUFACTURING OUTPUT (% CHANGE)	2.0	-1.2	3.7	1.5	4.0	1.0	1.7
HOUSING STARTS (000's)	76.7	61.1	59.1	70.2	75.0	68.2	64.1
UNEMPLOYMENT RATE (%)	7.9	7.6	7.3	6.8	6.6	6.5	6.4
EMPLOYMENT GROWTH (% CHANGE)	0.7	1.8	0.8	0.7	1.1	1.1	1.0
CONSUMER PRICES (% CHANGE)	1.4	1.1	2.3	1.2	1.8	2.1	2.0
RETAIL SALES (% CHANGE)	1.6	2.3	5.0	4.2	4.7	3.7	3.2
WAGE RATE (% CHANGE)	2.2	0.9	2.5	2.7	4.0	2.9	2.6
REAL RESIDENTIAL NATURAL GAS PRICE (% CHANGE)	-9.4	4.8	3.8	-5.5	-7.7	15.5	-3.0
REAL COMMERCIAL NATURAL GAS PRICE (% CHANGE)	-12.0	6.8	5.8	-6.1	-10.5	20.1	-3.3

* The forecasts have been updated to reflect the Q1 2017 Economic Outlook.

Witnesses: H. Sayyan
M. Suarez

ECONOMIC OUTLOOK: REGIONS*

CALENDAR YEAR	2012	2013	2014	2015	2016	2017F	2018F
FRANCHISE HOUSING STARTS (000's)	56.3	43.3	37.4	51.0	45.9	44.3	41.0
CENTRAL							
HOUSING STARTS (000's)	48.3	34.8	29.4	43.7	38.0	36.6	33.9
SINGLES	18.8	16.6	15.3	18.2	16.5	16.4	15.2
MULTIPLES	29.5	18.2	14.1	25.5	21.5	20.2	18.7
CONSUMER PRICES (% CHANGE)	1.6	1.1	2.4	1.6	2.0	2.1	2.0
EMPLOYMENT GROWTH (% CHANGE)	0.8	3.2	0.9	0.2	1.4	1.4	1.3
COMMERCIAL VACANCY RATE (%)	6.8	7.1	7.8	7.8	7.8	7.8	7.8
INDUSTRIAL VACANCY RATE (%)	6.1	5.9	5.5	4.4	3.4	3.4	3.4
VINTAGE METRO REGION CENTRAL WEATHER ZONE (% CHANGE)	-0.6	-0.7	-0.5	-0.5	-0.5	-0.6	-0.6
VINTAGE WESTERN REGION CENTRAL WEATHER ZONE (% CHANGE)	-1.9	-1.9	-1.8	-1.9	-1.7	-1.7	-1.7
VINTAGE CENTRAL REGION CENTRAL WEATHER ZONE (% CHANGE)	-1.8	-1.6	-2.0	-1.8	-1.6	-1.7	-1.7
VINTAGE NORTHERN REGION CENTRAL WEATHER ZONE (% CHANGE)	-2.5	-2.2	-2.0	-2.1	-2.2	-2.2	-2.1
CENTRAL HEATING DEGREE DAYS**	2388	2879	3326	2995	2574	2802	2782
EASTERN							
HOUSING STARTS (000's)	6.73	7.13	6.05	5.42	5.52	5.96	5.51
SINGLES	3.90	4.29	4.04	3.93	4.21	3.98	3.68
MULTIPLES	2.83	2.84	2.01	1.48	1.32	1.98	1.83
CONSUMER PRICES (% CHANGE)	1.4	0.9	1.9	1.0	1.3	2.0	1.9
EMPLOYMENT GROWTH (% CHANGE)	2.5	-1.3	1.2	-1.1	0.3	1.5	1.3
VINTAGE EASTERN WEATHER ZONE (% CHANGE)	-2.5	-2.4	-2.4	-1.9	-1.6	-2.3	-2.3
EASTERN HEATING DEGREE DAYS **	3160	3501	3804	3619	3270	3369	3387
NIAGARA							
HOUSING STARTS (000's)	1.25	1.37	1.86	1.87	2.40	1.71	1.58
SINGLES	1.06	1.29	1.80	1.61	1.98	1.52	1.40
MULTIPLES	0.18	0.09	0.07	0.26	0.42	0.19	0.18
EMPLOYMENT GROWTH (% CHANGE)	2.7	-3.5	0.0	4.2	0.0	1.2	0.7
VINTAGE NIAGARA WEATHER ZONE (% CHANGE)	-1.1	-1.3	-1.5	-1.5	-1.3	-1.3	-1.3
NIAGARA HEATING DEGREE DAYS **	2318	2795	3199	2948	2504	2701	2691

* The forecasts have been updated to reflect the Q1 2017 Economic Outlook.

**Balance Point Heating Degree Days are adjusted for billing cycles. The 2017 and 2018 Degree Day forecasts for all weather zones are generated by the methods approved by the Board in its EB-2012-0459 Decision with Reasons dated July 17, 2014.

Witnesses: H. Sayyan
M. Suarez

BUDGET DEGREE DAYS

1. The purpose of this evidence is to provide the forecast of degree days for the 2018 test year.

2. The 2018 degree day forecasts were prepared in accordance with the Ontario Energy Board's (the "Board") EB-2012-0459 Decision with Reasons dated July 17, 2014. The Board has approved the use of the 50:50 Hybrid method for the Central weather zone, the de Bever with Trend method for the Eastern weather zone and the 10-year moving average method for the Niagara weather zone. Table 1 displays the 2018 degree day forecasts that were generated according to the approved methodologies for each weather zone within the franchise using Environment Canada degree days. Conversions to Gas Supply degree days are depicted in the latter part of this evidence.

Table 1
Forecast of 2018 Environment Canada Degree Days

Region	*Methodology*	*Forecast*
Central	50:50 Hybrid	3,686
Eastern	De Bever with Trend	4,368
Niagara	10-year moving average	3,407

Degree Day Forecast Methodology

3. The degree day forecast for the Central weather zone was prepared using the 50:50 Hybrid method which is an average of the 10-year Moving Average and the 20-year Trend forecast. Table 2 provides the actual Environment Canada degree day data for the Central weather zone and the resultant 10-year moving average, 20-year Trend, and 50:50 Hybrid forecast. The 10-year moving average is calculated using

data covering the period 2007 to 2016[1], while 20-year Trend model is estimated for the period 1997 to 2016. The 20-year Trend model results are provided in Table 3.

Table 2
Environment Canada Degree Day Forecast – Central

Col. 1	*Col. 2*
Calendar Year	Actual[1]
1997	4,026
1998	3,220
1999	3,539
2000	3,826
2001	3,420
2002	3,630
2003	3,982
2004	3,798
2005	3,797
2006	3,378
2007	3,722
2008	3,837
2009	3,836
2010	3,501
2011	3,648
2012	3,215
2013	3,775
2014	4,103
2015	3,766
2016	3,462
2018 Forecast (10-year Moving average)	3,686
2018 Forecast (20-year Trend)[2]	3,686
2018 Forecast (50:50 Hybrid)[3]	3,686

[1]Environment Canada heating degree day observations from Pearson Int't Airport until June 2013. Effective June 13th, 2013 Environment Canada is no longer able to provide degree day data for Pearson Int'l Airport. Data from June 12th, 2013 and thereafter are obtained from the Toronto Int'l A station.

[2]Calculated using the 20-year Trend regression equation from Table 3.

[3]Average of 10-year Moving average and 20-year Trend forecasts.

[1] The 10 year moving average for year *t* is calculated as (DD_{t-2}+DD_{t-3}+ … +DD_{t-10}+DD_{t-11})/10 where DD is the actual degree day value.

Witnesses: H. Sayyan
M. Suarez

Table 3

Model Results & Test Statistics: 20-year Trend Methodology

Sample: 1997 2016 Included observations: 20

Col. 1	*Col. 2*	*Col. 3*	*Col. 4*	*Col. 5*
Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	3,660.571	128.44	28.50	0.000
TREND	1.1617	9.98	0.12	0.909
R-squared	0.001	F-statistic	0.01	
		F-prob	0.91	

Environment Canada Central Degree Day= 3,660.571-1.1617*TREND

The trend variable takes the values of 1 through 20 for each of the years from 1997 to 2016. The value of 22 is used for 2018 to generate 2018 degree day forecast.

4. The degree day forecast for the Eastern weather zone was prepared using the de Bever with Trend method. This method regresses actual Environment Canada degree days on a constant, a 5-year weighted average of Environment Canada degree days[2] and a trend. The 5-year weighted averages are lagged two years. Table 4 displays the actual Environment Canada degree day data for the Eastern weather zone, the 5-year weighted averages used to estimate the model, and the resultant degree day forecast for 2018. The model is estimated over the period 1950 to 2016 for a total of 67 years which is determined by the cycle length with smallest variance. Estimation results are provided in Table 5.

---

[2] The five-year weighted average for year *t* is calculated as $(5*DD_{t-2}+4*DD_{t-3}+3*DD_{t-4}+2*DD_{t-5}+DD_{t-6})/15$ where DD is the actual degree day value.

Witnesses: H. Sayyan
M. Suarez

Table 4
Environment Canada Degree Day Forecast – Eastern

Col. 1	*Col. 2*	*Col.3*
Calendar Year	Actual[1]	5-year Weighted MA[2]
1950	4,824	4,665
1951	4,587	4,594
1952	4,404	4,661
1953	4,059	4,641
1954	4,707	4,556
1955	4,689	4,385
1956	4,799	4,465
1957	4,405	4,523
1958	4,736	4,626
1959	4,718	4,584
1960	4,451	4,652
1961	4,586	4,669
1962	4,826	4,596
1963	4,921	4,584
1964	4,569	4,667
1965	4,810	4,753
1966	4,683	4,709
1967	4,882	4,755
1968	4,780	4,735
1969	4,698	4,775
1970	4,899	4,778
1971	4,797	4,762
1972	5,014	4,805
1973	4,420	4,808
1974	4,725	4,876
1975	4,514	4,736
1976	5,008	4,723
1977	4,597	4,637
1978	4,939	4,741
1979	4,589	4,695
1980	4,920	4,790
1981	4,438	4,735
1982	4,647	4,798
1983	4,536	4,674
1984	4,535	4,658
1985	4,659	4,601
1986	4,501	4,570
1987	4,328	4,585
1988	4,640	4,564
1989	4,931	4,482
1990	4,250	4,524
1991	4,303	4,657
1992	4,861	4,537
1993	4,780	4,461
1994	4,730	4,585
1995	4,585	4,646
1996	4,603	4,681
1997	4,786	4,680
1998	3,828	4,664
1999	4,137	4,689
2000	4,543	4,399
2001	4,115	4,276
2002	4,381	4,328
2003	4,715	4,240
2004	4,637	4,273
2005	4,421	4,444
2006	4,037	4,531
2007	4,447	4,511
2008	4,488	4,373
2009	4,534	4,376
2010	3,973	4,388
2011	4,144	4,430
2012	4,055	4,293
2013	4,402	4,242
2014	4,632	4,155
2015	4,486	4,209
2016	4,322	4,346
2018 Forecast (de Bever with Trend)[3]	4,368	

[1]Environment Canada heating degree day observations from MacDonald-Cartier Airport until December 2011. Effective December 15th, 2011, Environment Canada is no longer able to provide degree day data for MacDonald-Cartier Airport. Data from December 15th, 2011 and thereafter are obtained from the Ottawa Int'l A station.

[2]5-year weighted average lagged 2 years.

[3]Calculated using the de Bever with Trend regression equation from Table 5.

Table 5

Model Results & Test Statistics: De Bever with Trend Methodology

Sample: 1950 2016 Included observations: 67

Col. 1	*Col. 2*	*Col. 3*	*Col. 4*	*Col. 5*
Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	3,914.23	1,043.85	3.75	0.00
ECEDD5WA	0.1789	0.22	0.82	0.42
DBWT_TREND	-4.8815	1.92	-2.54	0.01
R-squared	0.19	F-statistic	7.58	
		F-prob	0.00	

Environment Canada Eastern Degree Day= 3,914.23+0.1789*ECEDD5WA-4.8815*TREND
5-year weighted average of 4,421 is used for 2018 to generate 2018 degree day forecast.
Trend variables takes the values from 1 to 67 for the period of 1950-2016. 69 is used for 2018 to generate 2018 degree day forecast.

5. The degree day forecast for the Niagara weather zone was prepared using the 10-year Moving Average method. Table 6 displays the actual Environment Canada degree day data for the Niagara weather zone and the resultant degree day forecast which is calculated using data covering the period 2007 to 2016[3].

[3] The 10 year moving average for year *t* is calculated as (DD_{t-2}+DD_{t-3}+ … +DD_{t-10}+DD_{t-11})/10 where DD is the actual degree day value.

Witnesses: H. Sayyan
M. Suarez

Table 6

Environment Canada Degree Day Forecast – Niagara

Col. 1	*Col. 2*
Calendar Year	Actual[1]
2007	3,296
2008	3,480
2009	3,565
2010	3,344
2011	3,458
2012	3,021
2013	3,527
2014	3,832
2015	3,450
2016	3,100
2018 Forecast (10-yr Moving average)	3,407

[1]Environment Canada heating degree day observations from St. Catherines Airport until August 2008. Effective September 2008 Environment Canada is no longer able to provide degree day data for St.Catherines Airport. Data from September 2008 and thereafter are obtained from the Vineland Climate Station.

Gas Supply Degree Day Conversion

6. The final step in the degree day forecast involves the conversion of Environment Canada degree days to Gas Supply degree days. Environment Canada degree days are calculated as the average of degree days related to the daily minimum and maximum temperatures within a 24-hour period. On the other hand, Gas Supply degree days are determined relative to average hourly temperatures within a 24-hour period. The latter is used by EGD's Gas Control as it is perceived to be more representative of temperature variations within a given day. Although there are differences between the two measurements, the data sets are highly correlated.

Witnesses: H. Sayyan
M. Suarez

7. The conversion leverages the correlation between both series and is carried out by regressing actual Gas Supply degree days onto actual Environment Canada degree days. The resultant equation (one for each weather zone) is used to convert the Environment Canada degree day forecast to the Gas Supply degree day forecast. Tables 7, 8 and 9 display actual Environment Canada degree days, actual Gas Supply degree days and the resultant Gas Supply degree day forecasts for the 2018 test year for each of the Central, Eastern, and Niagara regions, respectively. Each conversion model uses a sample that is consistent with the prescribed approved methodology to generate the forecasts. The sample for the Eastern region utilizes all the historical data available for Gas Supply degree days.

Table 7

Determination of Gas Supply Equivalent Degree Days - Central

Col. 1	*Col. 2*	*Col. 3*
Calendar Year	Actual Environment Canada Degree Days	Actual Gas Supply Degree Days
1997	4,026	3,966
1998	3,220	3,202
1999	3,539	3,497
2000	3,826	3,784
2001	3,420	3,400
2002	3,630	3,597
2003	3,982	3,949
2004	3,798	3,766
2005	3,797	3,750
2006	3,378	3,355
2007	3,722	3,659
2008	3,837	3,801
2009	3,836	3,767
2010	3,501	3,466
2011	3,215	3,597
2012	3,775	3,194
2013	4,103	3,746
2014	4,103	4,044
2015	3,766	3,710
2016	3,462	3,412
2018 Forecast (10-year Moving average)[1]		3,640
2018 Forecast (20-year Trend)[2]		3,645
2018 Forecast (50:50 Hybrid)[3]		3,642

[1] 2018 forecast (10-year Moving average) is calculated using the following regression equation:
Gas Supply degree day =87.4+0.9636*(Environment Canada degree day)
R-squared=0.997, Adjusted R-squared=0.997, F-statistic=2,569.03, Prob(F-statistic)=0.000000
[2] 2018 forecast (20-year Trend) is calculated using the following regression equation:
Gas Supply degree day =97.98+0.9622*(Environment Canada degree day)
R-squared=0.998, Adjusted R-squared=0.997, F-statistic=7,208.7, Prob(F-statistic)=0.000000
[3] 2018 forecast (50:50 Hybrid) is an average of 10-year Moving average and 20-year Trend.

Witnesses: H. Sayyan
M. Suarez

Table 8

Determination of Gas Supply Equivalent Degree Days - Eastern

Col. 1	*Col. 2*	*Col. 3*
Calendar Year	Actual Environment Canada Degree Days	Actual Gas Supply Degree Days
1970	4,899	5,018
1971	4,797	4,584
1972	5,014	4,816
1973	4,420	4,480
1974	4,725	4,858
1975	4,514	4,229
1976	5,008	4,901
1977	4,597	4,604
1978	4,939	4,920
1979	4,589	4,550
1980	4,920	4,853
1981	4,438	4,361
1982	4,647	4,617
1983	4,536	4,515
1984	4,535	4,504
1985	4,659	4,648
1986	4,501	4,507
1987	4,328	4,268
1988	4,640	4,601
1989	4,931	4,883
1990	4,250	4,225
1991	4,303	4,270
1992	4,861	4,746
1993	4,780	4,715
1994	4,730	4,700
1995	4,585	4,530
1996	4,603	4,561
1997	4,786	4,711
1998	3,828	3,802
1999	4,137	4,112
2000	4,543	4,506
2001	4,115	4,071
2002	4,381	4,317
2003	4,715	4,663
2004	4,637	4,598
2005	4,421	4,397
2006	4,037	4,012
2007	4,447	4,411
2008	4,488	4,431
2009	4,534	4,472
2010	3,973	3,947
2011	4,144	4,108
2012	4,055	4,048
2013	4,402	4,484
2014	4,632	4,552
2015	4,486	4,397
2016	4,322	4,231
2018 Forecast[1]		4,331

[1] 2018 forecast is calculated using the following regression equation:

Gas Supply degree days = 154.5764+0.95602*(Environment Canada degree days)

R-squared=0.9380, Adjusted R-squared=0.9366, F-statistic=680.919, Prob(F-statistic)=0.000000

Witnesses: H. Sayyan
M. Suarez

Table 9

Determination of Gas Supply Equivalent Degree Days - Niagara

Col. 1	*Col. 2*	*Col. 3*
Calendar Year	Actual Environment Canada Degree Days	Actual Gas Supply Degree Days
2006	3,163	3,079
2007	3,296	3,349
2008	3,480	3,510
2009	3,565	3,547
2010	3,344	3,322
2011	3,458	3,334
2012	3,021	3,013
2013	3,527	3,537
2014	3,832	3,814
2015	3,450	3,548
2016	3,100	3,233
2018 Forecast[1]		3,421

[1]2018 forecast is calculated using the following regression equation:

Gas Supply degree days = 373.6082+0.8943*(Environment Canada degree days)

R-squared=0.9063□Adjusted R-squared=0.8946□F-statistic=77.36□Prob(F-statistic)=0.0000□

<u>2018 Degree Day Forecasts:</u>

Table 10

Summary of 2018 Degree Days Forecast

Region	***Environment Canada Degree Days***	***Gas Supply Degree Days***
Central	3,686	3,642
Eastern	4,368	4,331
Niagara	3,407	3,421

Witnesses: H. Sayyan
M. Suarez

AVERAGE USE FORECASTING MODEL

1. The purpose of this evidence is to present the forecasting methodology used to forecast average use for Rate 1 revenue class 20 and Rate 6 revenue classes 12, 48 and 73[1]. Rate 1 is the Company's residential rate class while Rate 6 is the Company's small apartment, commercial and industrial rate class. Revenue class 20 is forecast to comprise 86% of Rate 1 volumes while revenue classes 12, 48 and 73 are forecast to collectively comprise 94% of Rate 6 volumes in 2018. The forecasting methodology for the other revenue classes in Rate 1 and Rate 6 are very similar to the models presented in this exhibit. The evidence validates that the Company's models continue to be accurate predictors of average use.

2. The Company moved to a more objective forecasting methodology starting in the 2001 Budget year in order to address the Board's concern with the systemic bias attributed to the grassroots forecasting process. This forecasting methodology removes systemic or subjective bias by developing regression models to forecast average use for the Company's Rate 1 general service customers and Rate 6 general service customers. This econometric methodology has been in place since 2001, the forecasts of which have been accepted in settlement proposals and Board decisions since. As shown in Tables 1 to 3, 5 and 8, the models exhibit a high R^2 and low Root Mean Squared Percentage Error ("RMSPE") indicating that each of the regression models is a good predictor of average use.

[1] Rate 1 is comprised of: revenue class 10 - residential heating, revenue class 20 - residential space heating and water heating, revenue class 50 - space heating, water heating and pool heating, revenue class 60 – residential general service and revenue class 61 – residential water heating. Rate 6 is comprised of: revenue class 12 – apartment heating and other uses, revenue class 48 commercial heating and other uses, revenue class 73 industrial heating and other uses, revenue class 79 commercial general service, revenue class 83 – industrial general service, revenue class 86 – apartment general service, revenue class 90 – commercial air conditioning and space heating.

Witnesses: H. Sayyan
M. Suarez

3. The year-over-year growth rates in average use for all revenue classes are used as the basis for the average use forecast for Rate 1 and Rate 6 as shown at Exhibit C1, Tab 2, Schedule 1, Appendix A. Factors influencing overall average use include the number of new customers (both new construction and replacement customers), the timing of new customer additions to the system, rate migration, gas prices, economic conditions, other external policy changes (e.g., Building Code), and the Company's DSM programs. In addition, the Company included the impact of Cap and Trade in the overall price of natural gas to recognize its impact on consumption as part of the price signal to consumers. While average use changes for Rate 1 are fairly reflective of regression model results because of the homogenous nature of customers within this class, modeled Rate 6 average uses may be adjusted to account for known rate migration or specific changes in usage patterns for customers within this class. Please refer to Exhibit C1, Tab 2, Schedule 1 for a detailed explanation of the derivation of the Company's gas volume budget.

4. Average use is defined as gas volume per unlock customer. The econometric models presented here utilize historical data and relationships to estimate driver variable impacts and derive a top down forecast of average use. The models presented in this exhibit incorporate updated driver variables and historical data obtained from federal and provincial statistical agencies and the Company's database. Maintaining an econometric model is an ongoing process; consequently, the models must be monitored and refined to ensure they are valid and produce accurate forecasts of general service average use.

<u>Error Correction Model</u>

5. The Company uses Error Correction Models ("ECM") to forecast average use for Rate 1 and Rate 6. The ECM method and two step estimation procedure are

described more fully in Engle and Granger (1987).[2] The ECM uses the concept of cointegration or long-run association between variables.

6. In other words, variables hypothesized to be linked by some theoretical economic relationship should not diverge from each other in the long run. Such variables may drift apart in the short run; however, if they were to diverge without bound, an equilibrium relationship among such variables could not be said to exist. The ECM methodology has been used extensively in the energy field for modeling electricity sales[3] and natural gas prices[4].

7. The major difference between the ECM approach and the standard dynamic single-equation model is that the ECM approach explicitly takes into account both long-run equilibrium and short-run dynamic relationships in the determination of average use. It is known that economic theory can provide useful information about the variables relevant in the long-run. However, it is relatively silent on the short-run dynamics between variables. The ECM approach allows the historical data to determine the lag structures and short run dynamics.

8. The estimated models are used to generate a normalized forecast of average use. The main purpose of the normalized forecast is to derive average use such that the weather impact has been taken out. Using the estimated coefficients, weather normalized average use data are obtained by replacing actual degree days in the model with proposed degree days for 2018 for every year so that year-to-year

---

[2] Engle, R.F. and Granger, C.W.J (1987), "Cointegration and Error Correction: Representation, Estimation and Testing," *Econometrica*, Vol. 55, No.2.
[3] Engle, R.F., Granger, C.W.J. and Hallman, J.J. (1989), "Merging Short- and Long-Run Forecasts: An Application to Monthly Electricity Sales Forecasting," *Journal of Econometrics*, Vol.40.
[4] Bopp, A.E. (1990), "An Analytical Approach to Forecasting Natural Gas Prices," *AGA Forecasting Review*: American Gas Association.

percentage changes reflect the pure average use trend by eliminating weather variability. The forecast changes in average use by revenue class and region (weather zone) are then applied to 2017 values at the same level of granularity to derive the 2018 General Service volumes.

Average Use Forecasting Methodology

9. The model's specification is based on an objective criterion: to minimize both in-sample and out-of-sample forecast error. The discrepancy between actual average use and the model's forecast can be segregated into three major sources of uncertainty: (1) model specification, (2) forecast error from the driver variables used in the model, and (3) unexpected shocks or structural breaks. Sources (2) and (3) are not within the Company's control and will inevitably occur regardless of which forecasting methodology is adopted. Therefore the objective of the modeling procedure, described below, is to minimize the controllable source of error, the model's specification.

10. The main criteria for assessing the model's predictive ability is the model's forecast accuracy. A comparison of actual un-normalized average use versus the forecasts produced by the model is used to assess predictive ability. Forecast accuracy for 2018 is measured using both in-sample and out-of-sample Mean Percentage Error ("MPE") and RMSPE. In-sample, or ex-post, means that the estimated model incorporates the entire sample, in this case 1985 to 2016. Out-of-sample, or ex-ante, means that the model incorporates only a portion of the sample, in this case 1985 to 2014. Forecasts of average use are produced under both approaches and measured against actual average use from 2015 to 2016 quantitatively via MPE and RMSPE. A two year "hold out" sample is used to compute the out-of-sample forecast accuracy statistics since the forecasting horizon for volumetric budgeting purposes is two years.

11. Table 1 presents the forecast accuracy statistics for Rate 1 and Rate 6. The smaller the MPE and RMSPE, the better the model's forecast performance.

TABLE 1
FORECAST ERRORS - PERCENT VARIANCE & ROOT MEAN SQUARED PERCENTAGE ERROR

Col 1.	Col 2.	Col 3.
Forecast Error Method	Rate 1	Rate 6
In-Sample % Variance (2 Years)	0.76%	0.74%
In-Sample RMSPE (2 Years)	0.76%	1.32%
Out-of-Sample % Variance (2 Years)	1.66%	1.07%
Out-of-Sample RMSPE (2 Years)	1.72%	1.51%

$$MPE = \frac{1}{N}\sum_{i=1}^{N}\left(\frac{Forecast_i - Actual_i}{Actual_i}\right)$$

$$RMSPE = \sqrt{\frac{1}{N}\sum_{i=1}^{N}\left(\frac{Forecast_i - Actual_i}{Actual_i}\right)^2}$$

12. Consistent with the settlement of Issue 1.1 in the RP-2000-0040 Settlement Agreement, Tables 2 and 3 report the results that the models would generate using actual data to allow parties to compare results to the prior year's forecast. Tables 2 and 3 show the results that the models would have produced had all actual driver values been available at the time the forecast was produced. The tables are not updated for 2004 since there are no Board approved average use forecasts for this particular test year. In order to compare the variance between actual and Board

Witnesses: H. Sayyan
M. Suarez

Approved average use on the same basis, the actual results for each year have been normalized to the corresponding Board Approved degree days for each respective test year. The results in Tables 2 and 3 show the regression model is a good predictor of general service average use.

TABLE 2

RATE 1 IN-SAMPLE FORECAST COMPARISON

Col 1.	Col 2.	Col 3.	Col 4.	Col 5.	Col 6.	Col 7.	Col 8.
Year	Actual Normalized Average Use Per Customer	Board Approved Normalized Average Use Per Customer[1,3]	Variance Normalized Average Use Per Customer	% Variance Normalized Average Use Per Customer	Model's Normalized Average Use Per Customer[2]	Variance Normalized Average Use Per Customer	% Variance Normalized Average Use Per Customer
	(m3)	m(3)	(2-3)	100*((2-3)/3)	(m3)	(2-6)	100*((2-6)/6)
2001	3,014	3,044	(30)	-1.0%	3,022	(8)	-0.26%
2002	2,980	2,970	10	0.3%	2,963	17	0.57%
2003	2,877	2,892	(15)	-0.5%	2,897	(20)	-0.69%
2004	2,843	n/a	n/a	n/a	2,864	(21)	-0.73%
2005	2,890	2,953	(63)	-2.1%	2,929	(39)	-1.33%
2006	2,796	2,850	(54)	-1.9%	2,816	(20)	-0.71%
2007	2,726	2,687	39	1.5%	2,695	31	1.15%
2008	2,636	2,647	(11)	-0.4%	2,611	25	0.97%
2009	2,616	2,637	(21)	-0.8%	2,623	(6)	-0.24%
2010	2,579	2,622	(43)	-1.6%	2,550	29	1.15%
2011	2,594	2,643	(49)	-1.9%	2,607	(13)	-0.51%
2012	2,529	2,510	18	0.7%	2,528	1	0.02%
2013	2,547	2,568	(22)	-0.8%	2,517	30	1.18%
2014	2,475	2,433	41	1.7%	2,490	(15)	-0.60%
2015	2,427	2,419	9	0.4%	2,404	23	0.97%
2016	2,401	2,480	(79)	-3.2%	2,380	22	0.91%

[1]Board approved normalized average use from RP-2000-0040, RP-2001-0032, RP-2002-0133, RP-2003-0203, EB-2005-000, EB-2006-0034, EB-2007-0615, EB-2008-0219, EB-2009-0172, EB-2010-0146, EB-2011-0277, EB-2011-0354, EB-2012-0459, EB-2014-0276 and EB-2015-0114 for 2001, 2002, 2003, 2005, 2006, 2007, 2008, 2009, 2010, 2011,2012, 2013, 2014, 2015 and 2016 respectively.

[2]Model's normalized average use is generated by running the model using actual data and driver variable information.

[3]There is no Board approved normalized average use for 2004.

TABLE 3
RATE 6 IN-SAMPLE FORECAST COMPARISON

Col 1.	Col 2.	Col 3.	Col 4.	Col 5.	Col 6.	Col 7.	Col 8.
Year	Actual Normalized Average Use Per Customer	Board Approved Normalized Average Use Per Customer[1,3]	Variance Normalized Average Use Per Customer	% Variance Normalized Average Use Per Customer	Model's Normalized Average Use Per Customer[2]	Variance Normalized Average Use Per Customer	% Variance Normalized Average Use Per Customer
	(m3)	m(3)	(2-3)	100*((2-3)/3)	(m3)	(2-6)	100*((2-6)/6)
2001	22,510	22,643	(133)	-0.6%	22,706	(196)	-0.86%
2002	22,097	22,125	(28)	-0.1%	21,957	140	0.64%
2003	21,593	21,685	(92)	-0.4%	21,613	(20)	-0.09%
2004	21,472	n/a	n/a	n/a	21,377	95	0.44%
2005	22,241	22,507	(266)	-1.2%	22,334	(93)	-0.42%
2006	22,272	21,999	273	1.2%	22,149	123	0.55%
2007	22,783	21,010	1773	8.4%	22,973	(190)	-0.83%
2008	24,869	24,204	665	2.7%	25,273	(404)	-1.60%
2009	27,654	28,165	(512)	-1.8%	27,875	(222)	-0.79%
2010	29,106	27,949	1157	4.1%	29,691	(585)	-1.97%
2011	29,471	28,029	1442	5.1%	30,240	(769)	-2.54%
2012	28,941	30,122	(1182)	-3.9%	28,634	307	1.07%
2013	29,203	29,878	(675)	-2.3%	28,756	447	1.56%
2014	28,634	28,383	251	0.9%	28,535	99	0.35%
2015	28,600	28,341	259	0.9%	28,375	225	0.79%
2016	28,210	28,753	(543)	-1.9%	27,876	334	1.20%

[1]Board approved normalized average use from RP-2000-0040, RP-2001-0032, RP-2002-0133, RP-2003-0203, EB-2005-000, EB-2006-0034, EB-2007-0615, EB-2008-0219, EB-2009-0172, EB-2010-0146, EB-2011-0277, EB-2011-0354, EB-2012-0459, EB-2014-0276 and EB-2015-0114 for 2001, 2002, 2003, 2005, 2006, 2007, 2008, 2009, 2010, 2011,2012, 2013, 2014, 2015 and 2016 respectively.

[2]Model's normalized average use is generated by running the model using actual data and driver variable information.

[3]There is no Board approved normalized average use for 2004.

13. The primary goal of the average use forecast is to be accurate and objective. Ideally, the forecast error should be small in magnitude and distributed in a random fashion. Although the forecast errors in Tables 1, 2, and 3 are small in magnitude, forecast accuracy is conditional on driver variable forecast accuracy and the absence of any structural break between the historical period and the upcoming forecast period. Consequently, besides testing forecast accuracy, the models were subjected to a battery of diagnostic tests. These tests were run on the model to check for incorrect functional forms, parameter instability, structural breaks, omitted variables and randomness of residuals. Test results can be seen at Table 6 and 9, and are interpreted at paragraph 15.

Witnesses: H. Sayyan
M. Suarez

14. The following diagnostic tests were run on each model[5] (results are shown in Tables 6 and 9):

Breusch-Godfrey Serial Correlation LM Test

This test is used to test for autocorrelation in the residuals. Autocorrelation occurs when disturbances in a regression equation are serially correlated. If there is evidence of serial correlation, first order autoregressive term ("AR(1)") is included in the model to improve the results. AR(1) addresses serial correlation by introducing lags so that a relationship is evaluated between the value at the present time using the value at the previous time. The test is set up as follows:

Null Hypothesis: No serial correlation
Alternative Hypothesis: Serial correlation

ARCH Test

This test is used to test for Autoregressive Conditional Heteroskedasticity ("ARCH"). ARCH occurs when the variance of disturbances in a regression equation are not constant and are serially correlated. The test is set up as follows:

Null Hypothesis: No ARCH
Alternative Hypothesis: ARCH

Chow Forecast Test

This test is used to test for stability of a regression model. A regression model is not stable if the estimated coefficients change (and consequently the model's predictions) when estimated over various sample ranges. Structural breaks can occur in time series

[5] The Durbin-Watson test is not used since it is not valid when there are lagged dependent variables in a regression equation. The Durbin Watson test is biased toward the finding of no serial correlation if there are lagged values of the dependent variable in the regression equation.

data, when there is a significant and sudden change in the relationship being examined. Dummy variables are included in the model to suppress the impact of a structural break[6]. The test is set up as follows:

Null Hypothesis: No structural change
Alternative Hypothesis: Structural change

Ramsey RESET Test

This is a general test which tests for omitted variables, incorrect functional form and correlation between the independent variables and disturbances. The test is set up as follows:

Null Hypothesis: Normally distributed disturbances (zero mean, constant variance)
Alternative Hypothesis: Non- normally distributed disturbances (non-zero mean, constant variance)

15. The following tables present the mnemonics used in the models (Tables 4 and 7), the regression equations for each model (Tables 5 and 8), and the diagnostic tests results run on the models (Tables 6 and 9). For the t tests in the regression equations shown at Tables 5 and 8, the p-values indicate the probability of obtaining a forecast at least as extreme as one that was actually observed, assuming that the null hypothesis (coefficient is not significant) is true. The p-value is compared to a significance level which is often 0.05 or 0.10, so that if its value is smaller, the null hypothesis is rejected at the 95% or 90% confidence level, respectively. The smaller the p-value, the more strongly the test rejects the null hypothesis, thereby supporting the statistical significance of the coefficient. In any instance where insignificant variables were retained within the models, it was for the

[6] Dummy variables are retained in the models only when regression results are improved.

purposes of (1) improving the significance of other coefficients or (2) optimizing forecast accuracy (3) importance of the variable. In contrast, for the diagnostic test results shown in Tables 6 and 9, the null hypotheses tested are the desired outcomes. In each case, to support the null hypothesis, p-values in excess of 0.10 are preferred. Overall, diagnostic test results in Table 6 and 9 show that the models in Table 5 and 8 are statistically valid and no assumptions appear to be violated at the 95% confidence level except the ‘No structural change’ assumption for Metro region revenue class 20 (Rate 1) and Eastern region revenue class 73 models. The Chow forecast test result for those two models has indicated the existence of structural change in 2016. Dummy variables have been introduced to those models to correct this.[7]

[7] See footnotes in Table 6 and 9 on page 14 and 19. See also Exhibit C1, Tab 2, Schedule 1, para. 20.

TABLE 4 - RATE 1 MODEL MNEMONICS

Mnemonic	Definition
C	Constant Term
LOG(X)	Logarithm of Variable X
DLOG(X)	LOG(X_t) - LOG(X_{t-1}), First Difference of Logarithm of Variable X
CDD, EDD, NDD	Balance Point Heating Degree Days for Central, Eastern and Niagara Weather Zones
MET20VINT	Vintage Variable for the Metro Region, Central Weather Zone
WES20VINT	Vintage Variable for the Western Region, Central Weather Zone
CEN20VINT	Vintage Variable for the Central Region, Central Weather Zone
NOR20VINT	Vintage Variable for the Northern Region, Central Weather Zone
ERC20VINT	Vintage Variable for the Eastern Weather Zone
NRC20VINT	Vintage Variable for the Niagara Weather Zone
REALCRCRPG	Real Residential Natural Gas Price for the Central Weather Zone
REALERCRPG	Real Residential Natural Gas Price for the Eastern Weather Zone
REALERCRPG	Real Residential Natural Gas Price for the Niagara Weather Zone
DUM2008-2010	Dummy Variables for Recession Impact
DUMXXXX	Dummy Variable for the Break in the Year XXXX
CENTEMP	Central Weather Zone Employment
AR(p)	pth-order Autoregressive Process Term
ECM_Region	Error Correction Term for Each Region

Witnesses: H. Sayyan
M. Suarez

TABLE 5 - RATE 1 REVENUE CLASS 20 REGRESSION EQUATIONS

Metro Region - Central Weather Zone

Long Run Equation

Variable	Coefficient	t-Statistic	p-Value
C	2.64	10.25	0.00
LOG(CDD)	0.70	21.72	0.00
LOG(REALCRCRPG)	-0.03	-1.61	0.12
LOG(MET20VINT)	0.89	11.46	0.00
DUM2008	-0.04	-3.66	0.00
DUM2010	-0.04	-2.79	0.01
DUM2016	-0.04	-2.71	0.01
R-squared	0.99		
Adjusted R-squared	0.99		
S.E. of regression	0.01		
F-statistic	545.33		0.00

Short Run Equation

Variable	Coefficient	t-Statistic	p-Value
C	0.00	0.06	0.96
DLOG(CDD)	0.76	33.49	0.00
DLOG(MET20VINT)	1.06	1.93	0.06
DUM2008	-0.01	-1.64	0.11
ECM_MET20(-1)	-0.30	-1.54	0.14
R-squared	0.98		
Adjusted R-squared	0.98		
S.E. of regression	0.01		
F-statistic	317.11		0.00

Western Region - Central Weather Zone

Long Run Equation

Variable	Coefficient	t-Statistic	p-Value
C	0.84	1.10	0.28
LOG(CDD)	0.70	26.56	0.00
LOG(REALCRCRPG)	-0.08	-5.13	0.00
LOG(WES20VINT)	0.49	6.05	0.00
LOG(CENTEMP)	0.20	2.26	0.03
DUM2008	-0.03	-3.04	0.01
DUM2010	-0.05	-3.83	0.00
R-squared	0.99		
Adjusted R-squared	0.99		
S.E. of regression	0.01		
F-statistic	669.63		0.000

Short Run Equation

Variable	Coefficient	t-Statistic	p-Value
C	0.00	-2.24	0.03
DLOG(CDD)	0.73	40.80	0.00
DLOG(REALCRCRPG)	-0.07	-3.94	0.00
DUM2008	-0.01	-2.25	0.03
ECM_WES20(-1)	-0.60	-3.01	0.01
R-squared	0.99		
Adjusted R-squared	0.99		
S.E. of regression	0.01		
F-statistic	669.63		0.000

Central Region - Central Weather Zone

Long Run Equation

Variable	Coefficient	t-Statistic	p-Value
C	0.62	0.80	0.43
LOG(CDD)	0.71	21.85	0.00
LOG(REALCRCRPG)	-0.02	-1.62	0.12
LOG(CEN20VINT)	0.58	8.53	0.00
LOG(CENTEMP)	0.22	2.51	0.02
DUM2008	-0.04	-3.73	0.00
R-squared	0.99		
Adjusted R-squared	0.99		
S.E. of regression	0.01		
F-statistic	645.70		0.000

Short Run Equation

Variable	Coefficient	t-Statistic	p-Value
C	0.00	0.12	0.90
DLOG(CDD)	0.71	30.95	0.00
DLOG(REALCRCRPG)	-0.04	-1.47	0.15
DUM2008	-0.01	-1.33	0.19
DLOG(CEN20VINT)	0.40	1.90	0.07
ECM_CEN20(-1)	-0.90	-4.58	0.00
R-squared	0.98		
Adjusted R-squared	0.97		
S.E. of regression	0.01		
F-statistic	215.73		0.000

Witnesses: H. Sayyan
M. Suarez

TABLE 5 CONTINUED - RATE 1 REVENUE CLASS 20 REGRESSION EQUATIONS

Northern Region - Central Weather Zone

Long Run Equation

Variable	Coefficient	t-Statistic	p-Value
C	0.62	0.71	0.49
LOG(CDD)	0.70	23.51	0.00
LOG(REALCRCRPG)	-0.07	-4.17	0.00
LOG(NOR20VINT)	0.52	7.62	0.00
LOG(CENTEMP)	0.24	2.36	0.03
DUM2009	-0.04	-3.47	0.00
R-squared	0.99		
Adjusted R-squared	0.99		
S.E. of regression	0.01		
F-statistic	883.74		0.000

Short Run Equation

Variable	Coefficient	t-Statistic	p-Value
C	0.00	-0.46	0.65
DLOG(CDD)	0.70	33.29	0.00
DLOG(REALCRCRPG)	-0.06	-2.64	0.01
DLOG(NOR20VINT)	0.30	1.68	0.10
ECM_NOR20(-1)	-0.93	-4.63	0.00
R-squared	0.98		
Adjusted R-squared	0.97		
S.E. of regression	0.01		
F-statistic	287.11		0.000

Eastern Weather Zone

Long Run Equation

Variable	Coefficient	t-Statistic	p-Value
C	1.66	5.75	0.00
LOG(EDD)	0.78	21.94	0.00
LOG(REALERCRPG)	-0.03	-1.96	0.06
LOG(ERC20VINT)	0.44	17.91	0.00
DUM2008	-0.02	-2.01	0.05
DUM2010	-0.03	-2.28	0.03
R-squared	0.99		
Adjusted R-squared	0.99		
S.E. of regression	0.01		
F-statistic	851.38		0.000

Short Run Equation

Variable	Coefficient	t-Statistic	p-Value
C	0.00	-0.39	0.70
DLOG(EDD)	0.82	31.57	0.00
DLOG(ERC20VINT)	0.45	3.47	0.00
ECM_ERC20(-1)	-0.70	-2.99	0.01
AR(1)	-0.56	-2.72	0.01
R-squared	0.98		
Adjusted R-squared	0.97		
S.E. of regression	0.01		
F-statistic	282.19		0.000

Niagara Weather Zone

Long Run Equation

Variable	Coefficient	t-Statistic	p-Value
C	2.17	6.67	0.00
LOG(NDD)	0.73	17.94	0.00
LOG(REALNRCRPG)	-0.03	-1.45	0.16
LOG(NRC20VINT)	1.19	12.94	0.00
DUM2008	-0.04	-2.62	0.01
DUM2010	-0.03	-1.41	0.17
R-squared	0.99		
Adjusted R-squared	0.99		
S.E. of regression	0.02		
F-statistic	485.73		0.000

Short Run Equation

Variable	Coefficient	t-Statistic	p-Value
C	-0.01	-4.43	0.00
DLOG(NDD)	0.74	25.70	0.00
ECM_NRC20(-1)	-0.60	-3.22	0.00
R-squared	0.96		
Adjusted R-squared	0.96		
S.E. of regression	0.02		
F-statistic	363.35		0.000

Witnesses: H. Sayyan
M. Suarez

TABLE 6 - RATE 1

Model Diagnostic Tests

Col 1.	Col 2.	Col 3.	Col 4.	Col 5.	Col 6.	Col 7.	Col 8.
Test		Metro Region	Western Region	Central Region	Northern Region	Eastern Weather Zone	Niagara Weather Zone
Breusch-Godfrey Serial Correlation LM Test	Test Statistic	1.49	0.81	0.07	0.13	0.21	0.12
	P Value	0.22	0.37	0.78	0.71	0.65	0.73
ARCH Test	Test Statistic	0.22	1.00	0.62	0.01	2.93	0.00
	P Value	0.64	0.32	0.43	0.93	0.10	0.94
Chow Forecast Test: Forecast from 2016 to 2016	Test Statistic	0.55	0.05	1.01	3.80	2.54	0.00
	P Value	0.46	0.82	0.33	0.06	0.12	1.00
Ramsey RESET Test	Test Statistic	1.10	2.51	1.12	0.56	3.32	0.00
	P Value	0.31	0.13	0.30	0.46	0.08	1.00

Dummy variable for 2016 (DUM2016) is added to Metro Region's long-run model because Chow Forecast test was significant with prob (0.01).

Witnesses: H. Sayyan
M. Suarez

TABLE 7 - RATE 6 MODEL MNEMONICS

Mnemonic	Definition
C	Constant Term
LOG(X)	Logarithm of Variable X
DLOG(X)	LOG(X_t) - LOG(X_{t-1}), First Difference of Logarithm of Variable X
CDD, EDD, NDD	Balance Point Heating Degree Days for Central, Eastern and Niagara Weather Zones
CENTEMP	Central Weather Zone Employment
EASTEMP	Eastern Weather Zone Employment
NIAGEMP	Niagara Weather Zone Employment
REALCRCCPG	Real Commercial Gas Price for the Central Weather Zone
REALERCCPG	Real Commercial Gas Price for the Eastern Weather Zone
REALNRCCPG	Real Natural Gas Price for the Niagara Weather Zone
ONTGDP	Ontario Real Gross Domestic Product
CRCCOMVAC	GTA Commercial Vacancy Rate
TIME	Time Trend
DUMRegion	Dummy Variable for Migration Impact
DUMXXXX	Dummy Variable for the Break in the Year XXXX
AR(p)	pth-order Autoregressive Process Term
ECM_Region	Error Correction Term for Each Region

Witnesses: H. Sayyan
M. Suarez

TABLE 8 - RATE 6 REVENUE CLASS 12 REGRESSION EQUATIONS

Central Revenue Class 12 (Apartment)

Single Equation Model

Variable	Coefficient	t-Statistic	p-Value
C	2.26	1.95	0.06
LOG(CDD)	0.61	8.37	0.00
LOG(CENTEMP)	0.56	5.09	0.00
DUM1996	-0.09	-4.18	0.00
DUM2008	0.21	5.55	0.00
AR(1)	0.50	2.49	0.02
R-squared	0.98		
Adjusted R-squared	0.97		
S.E. of regression	0.03		
F-statistic	199.729		0.000

Eastern Revenue Class 12 (Apartment)

Single Equation Model

Variable	Coefficient	t-Statistic	p-Value
C	3.28	2.35	0.03
LOG(EDD)	0.56	8.95	0.00
LOG(TIME)	-0.05	-4.13	0.00
DUMERC12	0.25	10.32	0.00
DUM2011	-0.13	-5.50	0.00
LOG(REALERCCPG)	-0.14	-3.39	0.00
LOG(EASTEMP)	0.48	2.65	0.01
DUM2014	0.06	3.12	0.00
R-squared	0.97		
Adjusted R-squared	0.97		
S.E. of regression	0.02		
F-statistic	133.24		0.000

Niagara Revenue Class 12 (Apartment)

Single Equation Model

Variable	Coefficient	t-Statistic	p-Value
C	4.73	4.15	0.00
LOG(NDD)	0.54	8.39	0.00
LOG(TIME)	-0.03	-2.80	0.01
LOG(NIAGEMP)	0.32	2.08	0.05
LOG(REALNRCCPG)	-0.05	-1.65	0.11
DUMNRC12	-0.07	-4.16	0.00
DUM2011	-0.10	-4.55	0.00
AR(1)	-0.31	-1.51	0.15
R-squared	0.92		
Adjusted R-squared	0.89		
S.E. of regression	0.03		
F-statistic	35.84		0.000

Witnesses: H. Sayyan
M. Suarez

TABLE 8 CONTINUED - RATE 6 REVENUE CLASS 48 REGRESSION EQUATIONS

Central Revenue Class 48 (Commercial)

Long Run Equation

Variable	Coefficient	t-Statistic	p-Value
C	-2.04	-1.89	0.07
LOG(CDD)	0.83	16.09	0.00
LOG(TIME)	-0.16	-10.00	0.00
LOG(CRCCOMVAC)	-0.05	-3.20	0.00
LOG(ONTGDP)	0.44	5.90	0.00
LOG(REALCRCCPG)	-0.07	-3.12	0.00
DUM2008	0.08	5.07	0.00
R-squared	0.96		
Adjusted R-squared	0.95		
S.E. of regression	0.02		
F-statistic	108.84		0.000

Short Run Equation

Variable	Coefficient	t-Statistic	p-Value
C	0.01	1.96	0.06
DLOG(CDD)	0.83	32.72	0.00
DLOG(TIME)	-0.09	-4.56	0.00
DLOG(CRCCOMVAC)	-0.07	-4.88	0.00
DLOG(REALCRCCPG)	-0.07	-3.35	0.00
ECM_CRC48(-1)	-0.76	-5.24	0.00
R-squared	0.98		
Adjusted R-squared	0.97		
S.E. of regression	0.01		
F-statistic	217.40		0.000

Eastern Revenue Class 48 (Commercial)

Long Run Equation

Variable	Coefficient	t-Statistic	p-Value
C	-1.43	-0.90	0.38
LOG(EDD)	0.71	8.04	0.00
LOG(TIME)	-0.20	-9.80	0.00
LOG(ONTGDP)	0.45	4.42	0.00
LOG(REALERCCPG)	-0.11	-3.10	0.00
DUM2008	0.13	6.00	0.00
R-squared	0.93		
Adjusted R-squared	0.92		
S.E. of regression	0.03		
F-statistic	70.22		0.000

Short Run Equation

Variable	Coefficient	t-Statistic	p-Value
C	0.01	1.42	0.17
DLOG(EDD)	0.72	11.35	0.00
DLOG(TIME)	-0.14	-3.54	0.00
DLOG(REALERCCPG)	-0.09	-1.98	0.06
ECM_ERC48(-1)	-0.85	-4.52	0.00
R-squared	0.86		
Adjusted R-squared	0.84		
S.E. of regression	0.03		
F-statistic	41.45		0.000

Niagara Revenue Class 48 (Commercial)

Long Run Equation

Variable	Coefficient	t-Statistic	p-Value
C	1.43	1.04	0.31
LOG(NDD)	0.74	12.37	0.00
LOG(TIME)	-0.06	-3.10	0.00
LOG(REALNRCCPG)	-0.09	-2.69	0.01
LOG(ONTGDP)	0.19	2.04	0.05
DUM2009	0.06	2.75	0.01
R-squared	0.90		
Adjusted R-squared	0.88		
S.E. of regression	0.03		
F-statistic	46.91		0.000

Short Run Equation

Variable	Coefficient	t-Statistic	p-Value
C	0.00	0.09	0.93
DLOG(NDD)	0.76	13.97	0.00
DLOG(REALNRCCPG)	-0.09	-2.05	0.05
ECM_NRC48(-1)	-0.86	-3.47	0.00
R-squared	0.90		
Adjusted R-squared	0.89		
S.E. of regression	0.03		
F-statistic	81.63		0.000

Witnesses: H. Sayyan
M. Suarez

TABLE 8 CONTINUED - RATE 6 REVENUE CLASS 73 REGRESSION EQUATIONS

Central Revenue Class 73 (Industrial)

Long Run Equation

Variable	Coefficient	t-Statistic	p-Value
C	1.63	0.60	0.56
LOG(CDD)	0.47	2.77	0.01
LOG(TIME)	-0.15	-3.88	0.00
LOG(ONTGDP)	0.45	2.80	0.01
DUM2008	0.52	13.04	0.00
R-squared	0.92		
Adjusted R-squared	0.91		
S.E. of regression	0.07		
F-statistic	80.02		0.000

Short Run Equation

Variable	Coefficient	t-Statistic	p-Value
C	-0.02	-2.12	0.04
DLOG(CDD)	0.57	9.31	0.00
DLOG(ONTGDP)	0.69	2.26	0.03
DUM2008	0.24	6.40	0.00
DUM2009	-0.19	-4.98	0.00
ECM_CRC73(-1)	-0.64	-6.49	0.00
R-squared	0.87		
Adjusted R-squared	0.85		
S.E. of regression	0.03		
F-statistic	33.82		0.000

Eastern Revenue Class 73 (Industrial)

Single Equation Model

Variable	Coefficient	t-Statistic	p-Value
C	-319,256	-3.67	0.00
EDD	34	2.59	0.02
DUM2003	57,734	3.37	0.00
DUM2004	-160,947	-7.23	0.00
DUM2009	122,447	11.50	0.00
EASTEMP	671	4.91	0.00
TIME	-5,568	-5.07	0.00
DUM2016	110,592	6.46	0.00
R-squared	0.96		
Adjusted R-squared	0.95		
S.E. of regression	15,508.71		
F-statistic	82.62		0.000

Niagara Revenue Class 73 (Industrial)

Single Equation Model

Variable	Coefficient	t-Statistic	p-Value
C	-0.89	-0.25	0.81
LOG(NDD)	0.72	3.33	0.00
DUM2002	-0.37	-4.13	0.00
DUM2007	0.48	4.52	0.00
DUM2010	0.42	3.89	0.00
LOG(NIAGEMP)	1.24	2.41	0.02
AR(1)	0.64	3.50	0.00
R-squared	0.97		
Adjusted R-squared	0.96		
S.E. of regression	0.10		
F-statistic	115.76		0.000

Witnesses: H. Sayyan
M. Suarez

TABLE 9-RATE 6
Model Diagnostic Tests

Col 1.	Col 2.	Col 3.	Col 4.	Col 5.	Col 6.	Col 7.	Col 8.	Col 9.	Col 10.	Col 11.
		Revenue Class 12 (Apartment) Model Diagnostic Tests			**Revenue Class 48 (Commercial) Model Diagnostic Tests**			**Revenue Class 73 (Industrial) Model Diagnostic Tests**		
Test		Central Weather Zone	Eastern Weather Zone	Niagara Weather Zone	Central Weather Zone	Eastern Weather Zone	Niagara Weather Zone	Central Weather Zone	Eastern Weather Zone	Niagara Weather Zone
Breusch-Godfrey Serial Correlation LM Test	Test Statistic	2.25	1.60	0.19	0.30	0.67	0.20	1.30	0.07	1.59
	P Value	0.13	0.21	0.66	0.58	0.41	0.66	0.25	0.80	0.21
ARCH Test	Test Statistic	0.21	1.31	1.73	0.23	3.20	0.58	0.52	0.21	1.80
	P Value	0.65	0.25	0.19	0.63	0.07	0.45	0.47	0.65	0.18
Chow Forecast Test: Forecast from 2016 to 2016	Test Statistic	0.05	0.50	0.30	1.71	0.37	0.20	1.82	41.71*	1.68
	P Value	0.82	0.49	0.59	0.20	0.55	0.66	0.19	0.00	0.21
Ramsey RESET Test	Test Statistic	1.00	0.84	0.28	0.16	0.55	0.28	1.01	1.34	2.00
	P Value	0.33	0.37	0.60	0.69	0.47	0.60	0.32	0.26	0.17

*Before DUM2016 is added into the model

Dummy variable for 2016 (DUM2016) is added to Eastern region Revenue class 73 short-run model because Chow Forecast test was significant with prob (0.00)

16. Major driver variables in the models are balance point heating degree days adjusted for billing cycles, vintage, a time trend, real natural gas prices and economic variables. Driver variable assumptions are shown in the Economic Outlook at Exhibit C2, Tab 1, Schedule 1.

17. Natural gas prices have an important impact on average use. Sharp increases typically have two effects. First, they influence customers' fuel use habits, for example, the lowering of thermostat settings. Second, price increases likely factor in customers' decision-making around the purchase of more efficient furnaces and other appliances. In addition, homeowners may also respond by retrofitting older residences in order to reduce energy consumption.

18. With the implementation of the Cap and Trade program, carbon price is now part of the distribution rate for natural gas. The Company has included the associated price impact in the overall natural gas price considered in the average use models. For major revenue classes (those with the majority of customers and volumes) where the gas price variable is not significant in the models, the variable is still retained to ensure Cap and Trade impacts are considered. The details of the Company's approach are detailed in Exhibit C1, Tab 2, Schedule 1, Appendix C.

19. Real natural gas prices are used in the average use models. The Consumer Price Index ("CPI") is used to convert nominal gas prices to real gas prices. Nominal energy price forecast for 2018 is based on the consensus Henry Hub price forecast produced in January 2017.

20. A linear time trend is used as a proxy measure for energy conservation. However, a linear time trend only reflects constant annual changes in appliance efficiency; it will not be able to reflect the time-varying impact of new residential construction on

appliance efficiency. Consequently, a vintage variable serves as either a supplementary or complementary variable to the time trend in the model.

21. The vintage variable (for revenue class 20 only) is employed as a proxy measure of gas space heating and gas water heating efficiency gains and residential thermal efficiency. Newer homes with improved thermal envelope characteristics and older homes adding insulation and storm windows/doors reduce the typical amount of gas needed for space heating. Residential thermal efficiency will continue to improve as newer, better-insulated residences account for a larger portion of the housing stock. The vintage variable captures the impact of both furnace efficiency and thermal efficiency on average use.

22. Vintage is defined as the calendar year in which the customer became a customer (new gas service main date) and is not based on the age of the building. This data includes both new construction and conversion customer additions. As space heating efficiency gains have a greater impact on average use than thermal improvements to homes, customers by vintage is a better variable than age of the building in terms of explaining the percentage decline in residential average use.

23. An illustration of the vintage ratio for 1992 follows:

$$V_{1992} = \frac{\sum_{y=1987}^{1991} V_y}{\sum_{yy=1987}^{1992} V_{yy}}$$ where V denotes vintage.

24. Calendar 1992 is used as the reference year for the vintage ratio since the Energy Efficiency Act prohibited selling of the conventional low-efficiency furnace in

Witnesses: H. Sayyan
M. Suarez

January 1992.[8] Consequently, this ratio will capture the increasing market share of both mid-efficiency and high-efficiency furnaces at the expense of declining market share of conventional furnaces over time. Generally, regions with stronger new construction additions experience a sharper decline in the ratio than established regions like Metro. As more new customers are added to the revenue class the declining ratio leads to lower average use over time. Thus, the coefficient of the vintage variable is a positive value.

25. Economic variables such as employment, vacancy rates, and gross domestic product can impact demand for new gas appliances as well as impact demand for natural gas for space heating and manufacturing processes. Stronger employment and demand for products both domestically and abroad will generally increase natural gas demand.

Risks to the Forecast

26. The impact of customer mix on average use is not static and changes over time. New customers may have different gas use characteristics than existing customers and may be influenced by builder specifications for inclusion/exclusion of new gas appliances. Thus, aggregate average use will be affected even if customers take no actions that could affect their average use. Advances in the future penetration of gas appliances above historical penetration levels implicit in the model could result in increased average use. Conversely, builder specification of non-gas water and/or space heating equipment represents a risk to the forecast as it could result in lower gas consumption than forecast.

[8] During the 1970s natural gas furnaces averaged about 65% Annual Fuel Utilization Efficiency (“AFUE”). The Energy Efficiency Act imposed 78% AFUE as a minimum for gas furnaces manufactured after January 1, 1992.

27. Cap and Trade charges have been included in the forecast of 2018 average use volumes (Exhibit C1, Tab 2, Schedule 1, Appendix C). As these charges are billed to customers within the natural gas distribution rate, customers will not see a distinct price that may bring about a different behavioral response than if the price increase was due to commodity cost increase, for instance. In other words, the price sensitivity or behavioral response (also, elasticity coefficient) is identical regardless of the source of the price change. To the extent that customers are inclined to consume less as a response to higher prices or as a conscious response to reduce emissions, the model impact is impartial. Actual consumption behavior cannot be measured and may play out differently than assumed.

28. New Building Code requirements came into effect in January 2017 that could potentially result in lower average uses than forecast. The potential reductions in average use are largely dependent on the installation options or compliance packages implemented by designers and builders, as well as when permits were applied for. While savings are difficult to model, it is estimated that the impacts will be minimal as forecast average uses are relatively close to the target reduction.

29. The Company has observed progressively higher energy content values over the past few years as a result of gas supplies from Marcellus-Utica taking up a larger share of gas supply. The average use forecast relies on historical average uses that have inherently lower / higher heat values than what would have been in effect in the test year due to the different mix of supplies. That is, volumes in the test year would, on average, have had a higher / lower effective energy content than what would have been implicit in the forecast, thereby possibly requiring lesser / greater volumes than anticipated to meet normalized energy requirements.

Witnesses: H. Sayyan
M. Suarez

30. The use of more efficient water heaters across the franchise area and / or the loss of natural gas water heating to other fuels could result in a permanent decrease in baseload usage and natural gas consumption relative to the forecast.

31. Gas consumption for space heating is very sensitive to thermostat settings. Customers may set their thermostats lower under extremely warm weather like that experienced in 1998, 2001, 2006, and most recently in 2012 and 2016.

32. Economic activity can impact both demand for appliances and natural gas. If the economy slows more significantly and natural gas prices are higher than indicated in the Economic Outlook (Exhibit C2, Tab 1, Schedule 1), average use will decline further.

33. A structural break in the historical estimated relationship between average use and the driver variables, such as that observed in 2016, will increase forecast risk as will forecast uncertainty in any of the other driver variables.

Conclusion

34. The model employed by the Company passes a battery of statistical tests and is valid given current and historical information. Continual evaluation and testing is required, as new information becomes available. The model has been estimated over volatile periods in history – recent years of unexpected warm and cold weather, historically high energy prices and increased energy price volatility. In light of these volatile economic and weather conditions, continuous model evaluation ensures that ongoing impacts in the relationship of average use and its driver variables is captured to produce the most accurate and objective forecast as possible.

Witnesses: H. Sayyan
M. Suarez

2018 CUSTOMER ADDITIONS

Customer Additions

1. The 2018 Forecast of customer additions, 2017 Board-Approved Budget of customer additions as filed in Enbridge's 2017 Rate Adjustment application at EB-2016-0215, and 2016 Actual customer additions are outlined in Table 1. The 2018 Forecast projects a slight increase in 2018 customer additions relative to 2016 Actuals and a decrease compared to the 2017 Budget.

2. The 2018 customer additions forecast was developed and informed by a number of sources including information gathered through direct contact with builders, developers, and municipalities as well as economic indicators such as housing starts, GDP growth, employment, and mortgage rates. The approach used to develop the forecast is consistent with the process used by the Company and approved by the Board in previous rate applications.

Residential Customers

3. The residential sector is comprised of the New Construction ("NC") and replacement markets and accounts for over 90% of the Company's customer additions forecast. Residential NC consists of new homes in new developments while the replacement market is comprised of customers in existing homes that switch to natural gas from other energy sources. Relative to the actual results in 2016 and 2017 Board-Approved Budget, growth in the NC market is forecasted to be flat in 2018. This forecast is in line with recent market trends and activity in builder markets.

4. Customer growth in the replacement sector is expected to stay positive, driven by the price advantage of natural gas relative to alternative fuels such as electricity,

propane and heating oil. Compared to previous forecasts and the actual customer additions in 2016, overall growth in the replacement sector is expected to slightly decline. Recent declines in this segment are due to increasing construction costs relative to historical averages which require higher contribution amounts from potential replacement customers consistent with feasibility criteria prescribed by the Board in EBO 188.

Commercial Customers

5. Economic stability in Ontario is expected to encourage investments in the commercial sector with moderate growth projected in both the commercial and apartment traditional segments. Commercial sector growth in 2018 is expected to be stronger than 2016 and slightly weaker than the 2017 Board-Approved Budget.

Industrial Customers

6. The growth expected in the industrial sector is higher than 2016 and slightly below the 2017 Budget. The Company is forecasting to add six industrial customers in 2017.

Table 1: Gross Customer Additions

Item No.	Sector	Col. 1 2016 Actual	Col. 2 2017 Budget Board-Approved	Col. 3 2018 Forecast
	Residential[1]			
1.1	New Construction	24,314	23,050	24,106
1.2	Replacement[2]	4,009	5,767	3,996
1.0	Total Residential	28,323	28,817	28,102
	Commercial[3]			
2.1	New Construction	1,139	1,840	1,707
2.2	Replacement	525	632	634
2.0	Total Commercial	1,664	2,472	2,341
	Industrial			
3.1	New Construction	1	8	6
3.2	Replacement	3	0	0
3.0	Total Industrial	4	8	6
4.0	Total Gross Customer Additions	29,991	31,297	30,449

1 *Residential customers include single homes and apartment ensuites*

2 *Replacement customers are existing homes and businesses, which switch from other energy sources to natural gas*

3 *Commercial customers include commercial and traditional apartment buildings*

UTILITY REVENUE
2018 UPDATED FORECAST (INCLUDING CIS & CUSTOMER CARE)

Line No.		Col. 1 EB-2012-0459 2018 Utility Placeholder Revenue ($Millions)	Col. 2 2018 CIR Update Adjustments ($Millions)	Col. 3 2018 Updated Forecast Utility Revenue ($Millions)
1.	Gas sales	2,496.2	129.0	2,625.2
2.	Transportation of gas	205.0	46.8	251.8
3.	Transmission, compression and storage revenue	1.8	17.4	19.2
4.	Other operating revenue	42.7	-	42.7
5.	Interest and property rental	-	-	-
6.	Other income	0.1	-	0.1
7.	Total operating revenue	2,745.8	193.2	2,939.0

Witness: R. Small

EXPLANATION OF ADJUSTMENTS TO UTILITY REVENUE
2018 UPDATED FORECAST (INCLUDING CIS & CUSTOMER CARE)

Line No. Adj'd	Adjustment ($Millions)	Explanation
1.	129.0	Gas Sales Adjustment to 2018 placeholder gas sales revenues to reflect the updated 2018 volume forecast and Board Approved July 1, 2017 rates.
2.	46.8	Transportation of gas Adjustment to 2018 placeholder transportation of gas revenues to reflect the updated 2018 volume forecast and Board Approved July 1, 2017 rates.
3.	17.4	Transmission, compression and storage revenue Adjustment to 2018 placeholder transmission, compression and storage revenues to reflect the updated 2018 volume forecast and Board Approved July 1, 2017 rates, inclusive of Rate 332.

CUSTOMER METERS AND VOLUMES BY RATE CLASS
2018 BUDGET

Item No.		Col. 1 Customers (Average)	Col. 2 Volumes (10^6m^3)		Col. 3 Revenues ($Millions)
General Service					
1.1.1	Rate 1 - Sales	1 942 680	4 593.9		1 695.7
1.1.2	Rate 1 - T-Service	72 397	166.6		36.5
1.1	Total Rate 1	2 015 077	4 760.5		1 732.2
1.2.1	Rate 6 - Sales	145 987	3 121.4		876.8
1.2.2	Rate 6 - T-Service	21 577	1 708.4		155.8
1.2	Total Rate 6	167 564	4 829.8		1 032.6
1.3.1	Rate 9 - Sales	0	0.0		0.0
1.3.2	Rate 9 - T-Service	0	0.0		0.0
1.3	Total Rate 9	0	0.0		0.0
1.	Total General Service Sales & T-Service	2 182 641	9 590.3		2 764.8
Contract Sales					
2.1	Rate 100	0	0.0		0.0
2.2	Rate 110	43	56.3		11.6
2.3	Rate 115	0	0.0		0.0
2.4	Rate 135	2	4.5		0.8
2.5	Rate 145	5	8.6		1.7
2.6	Rate 170	4	34.5		6.0
2.7	Rate 200	1	169.8		29.3
2.	Total Contract Sales	55	273.7		49.4
Contract T-Service					
3.1	Rate 100	0	0.0		0.0
3.2	Rate 110	222	732.7		33.7
3.3	Rate 115	27	542.8		12.3
3.4	Rate 125	4	0.0	*	10.9
3.5	Rate 135	41	60.0		1.9
3.6	Rate 145	31	41.6		1.8
3.7	Rate 170	21	256.7		2.6
3.8	Rate 300	1	0.0	*	0.1
3.9	Rate 315	0	0.0		0.0
3.	Total Contract T-Service	347	1 633.8		63.3
4.	Total Contract Sales & T-Service	402	1 907.5		112.7
5.	Total	2 183 043	11 497.8		2 877.5

* There is no distribution volume for Rate 125 and Rate 300 customers.

Witnesses: R. Cheung
M. Suarez

COMPARISON OF AVERAGE CUSTOMER METERS BY RATE CLASS
2018 BUDGET AND 2017 BOARD-APPROVED BUDGET

Item No.		Col. 1 2018 Budget	Col. 2 2017 Board-Approved Budget	Col. 3 2018 Budget Over (Under) 2017 Budget (1-2)
General Service				
1.1.1	Rate 1 - Sales	1 942 680	1 884 035	58 645
1.1.2	Rate 1 - T-Service	72 397	102 994	(30 597)
1.1	Total Rate 1	2 015 077	1 987 029	28 048
1.2.1	Rate 6 - Sales	145 987	144 811	1 176
1.2.2	Rate 6 - T-Service	21 577	21 668	(91)
1.2	Total Rate 6	167 564	166 479	1 085
1.3.1	Rate 9 - Sales	0	6	(6)
1.3.2	Rate 9 - T-Service	0	0	0
1.3	Total Rate 9	0	6	(6)
1.	Total General Service Sales & T-Service	2 182 641	2 153 514	29 127
Contract Sales				
2.1	Rate 100	0	0	0
2.2	Rate 110	43	44	(1)
2.3	Rate 115	0	0	0
2.4	Rate 135	2	1	1
2.5	Rate 145	5	5	0
2.6	Rate 170	4	4	0
2.7	Rate 200	1	1	0
2.	Total Contract Sales	55	55	0
Contract T-Service				
3.1	Rate 100	0	0	0
3.2	Rate 110	222	229	(7)
3.3	Rate 115	27	26	1
3.4	Rate 125	4	5	(1)
3.5	Rate 135	41	43	(2)
3.6	Rate 145	31	29	2
3.7	Rate 170	21	21	0
3.8	Rate 300	1	2	(1)
3.9	Rate 315	0	0	0
3.	Total Contract T-Service	347	355	(8)
4.	Total Contract Sales & T-Service	402	410	(8)
5.	Total	2 183 043	2 153 924	29 119

Witnesses: R. Cheung
M. Suarez

COMPARISON OF GAS SALES AND
TRANSPORTATION VOLUME BY RATE CLASS
2018 BUDGET AND 2017 BOARD-APPROVED BUDGET
($10^6 m^3$)

Item No.		Col. 1 2018 Budget	Col. 2 2017 Board-Approved Budget	Col. 3 2018 Budget Over (Under) 2017 Budget (Col. 1- Col. 2)
General Service				
1.1.1	Rate 1 - Sales	4 593.9	4 659.2	(65.3)
1.1.2	Rate 1 - T-Service	166.6	252.3	(85.7)
1.1	Total Rate 1	4 760.5	4 911.5	(151.0)
1.2.1	Rate 6 - Sales	3 121.4	3 104.3	17.1
1.2.2	Rate 6 - T-Service	1 708.4	1 757.9	(49.5)
1.2	Total Rate 6	4 829.8	4 862.2	(32.4)
1.3.1	Rate 9 - Sales	0.0	0.3	(0.3)
1.3.2	Rate 9 - T-Service	0.0	0.0	0.0
1.3	Total Rate 9	0.0	0.3	(0.3)
1.	Total General Service Sales & T-Service	9 590.3	9 774.0	(183.7)
Contract Sales				
2.1	Rate 100	0.0	0.0	0.0
2.2	Rate 110	56.3	67.3	(11.0)
2.3	Rate 115	0.0	0.0	0.0
2.4	Rate 135	4.5	1.2	3.3
2.5	Rate 145	8.6	8.3	0.3
2.6	Rate 170	34.5	35.7	(1.2)
2.7	Rate 200	169.8	170.8	(1.0)
2.	Total Contract Sales	273.7	283.3	(9.6)
Contract T-Service				
3.1	Rate 100	0.0	0.0	0.0
3.2	Rate 110	732.7	794.2	(61.5)
3.3	Rate 115	542.8	490.3	52.5
3.4	Rate 125	0.0 *	0.0 *	0.0
3.5	Rate 135	60.0	59.7	0.3
3.6	Rate 145	41.6	55.1	(13.5)
3.7	Rate 170	256.7	260.6	(3.9)
3.8	Rate 300	0.0	35.0	(35.0)
3.9	Rate 315	0.0	0.0	0.0
3.	Total Contract T-Service	1 633.8	1 694.9	(61.1)
4.	Total Contract Sales & T-Service	1 907.5	1 978.2	(70.7)
5.	Total	11 497.8	11 752.2	(254.4)

* There is no distribution volume for Rate 125 customers.

COMPARISON OF GAS SALES AND
TRANSPORTATION VOLUME BY RATE CLASS
2018 BUDGET AND 2017 BOARD-APPROVED BUDGET
($10^6 m^3$)

Item No.		Col. 1 2018 Budget	Col. 2 2017 Board-Approved Budget	Col. 3 2018 Budget Over (Under) 2017 Budget (Col. 1-Col. 2)	Col. 4 2017* Adjustments	Col. 5 2018 Budget Over (Under) 2017 Budget with Adjustments (Col. 3-Col. 4)
General Service						
1.1.1	Rate 1 - Sales	4 593.9	4 659.2	(65.3)	(15.9)	(49.4)
1.1.2	Rate 1 - T-Service	166.6	252.3	(85.7)	(1.1)	(84.6)
1.1	Total Rate 1	4 760.5	4 911.5	(151.0)	(17.0)	(134.0)
1.2.1	Rate 6 - Sales	3 121.4	3 104.3	17.1	(12.2)	29.3
1.2.2	Rate 6 - T-Service	1 708.4	1 757.9	(49.5)	(3.2)	(46.3)
1.2	Total Rate 6	4 829.8	4 862.2	(32.4)	(15.4)	(17.0)
1.3.1	Rate 9 - Sales	0.0	0.3	(0.3)	0.0	(0.3)
1.3.2	Rate 9 - T-Service	0.0	0.0	0.0	0.0	0.0
1.3	Total Rate 9	0.0	0.3	(0.3)	0.0	(0.3)
1.	Total General Service Sales & T-Service	9 590.3	9 774.0	(183.7)	(32.4)	(151.3)
Contract Sales						
2.1	Rate 100	0.0	0.0	0.0	0.0	0.0
2.2	Rate 110	56.3	67.3	(11.0)	0.0 **	(11.0)
2.3	Rate 115	0.0	0.0	0.0	0.0 **	0.0
2.4	Rate 135	4.5	1.2	3.3	0.0	3.3
2.5	Rate 145	8.6	8.3	0.3	0.0 **	0.3
2.6	Rate 170	34.5	35.7	(1.2)	0.0 **	(1.2)
2.7	Rate 200	169.8	170.8	(1.0)	0.0	(1.0)
2.	Total Contract Sales	273.7	283.3	(9.6)	0.0	(9.6)
Contract T-Service						
3.1	Rate 100	0.0	0.0	0.0	0.0	0.0
3.2	Rate 110	732.7	794.2	(61.5)	(0.1)	(61.4)
3.3	Rate 115	542.8	490.3	52.5	0.0 **	52.5
3.4	Rate 125	0.0	0.0	0.0	0.0	0.0
3.5	Rate 135	60.0	59.7	0.3	0.0	0.3
3.6	Rate 145	41.6	55.1	(13.5)	0.0 **	(13.5)
3.7	Rate 170	256.7	260.6	(3.9)	0.0 **	(3.9)
3.8	Rate 300	0.0	35.0	(35.0)	0.0	(35.0)
3.9	Rate 315	0.0	0.0	0.0	0.0	0.0
3.	Total Contract T-Service	1 633.8	1 694.9	(61.1)	(0.1)	(61.0)
4.	Total Contract Sales & T-Service	1 907.5	1 978.2	(70.7)	(0.1)	(70.6)
5.	Total	11 497.8	11 752.2	(254.4)	(32.5)	(221.9)

*Note: Weather normalization adjustments have been made to the 2017 Board Approved Budget utilizing the 2018 Budget degree days in order to place the two years on a comparable basis.

** Less than 50,000 m^3.

Witness: R. Cheung

COMPARISON OF GAS SALES AND
TRANSPORTATION VOLUME BY RATE CLASS
2018 BUDGET AND 2017 BOARD-APPROVED BUDGET
(10^6m^3)

Item No.		Col. 1 2018 Budget	Col. 2 2017 Board-Approved Budget	Col. 3 2018 Budget Over (Under) 2017 Budget (Col. 1-Col. 2)	Col. 4 Change in Use	Col. 5 Weather	Col. 6 New Customers	Col. 7 Transfer Gains	Col. 8 Transfer Losses	Col. 9 Lost Customers	Col. 10 DSM Adjustment
	General Service										
1.1.1	Rate 1 - Sales	4 593.9	4 659.2	(65.3)	(196.2)	(15.9)	66.1	87.3	0.0	0.0	(6.6)
1.1.2	Rate 1 - T-Service	166.6	252.3	(85.7)	2.9	(1.1)	0.0	0.0	(87.3)	0.0	(0.2)
1.1	Total Rate 1	4 760.5	4 911.5	(151.0)	(193.3)	(17.0)	66.1	87.3	(87.3)	0.0	(6.8)
1.2.1	Rate 6 - Sales	3 121.4	3 104.3	17.1	(18.4)	(12.2)	24.2	47.7	(12.5)	0.0	(11.7)
1.2.2	Rate 6 - T-Service	1 708.4	1 757.9	(49.5)	(27.3)	(3.2)	0.0	54.8	(67.4)	0.0	(6.4)
1.2	Total Rate 6	4 829.8	4 862.2	(32.4)	(45.7)	(15.4)	24.2	102.5	(79.9)	0.0	(18.1)
1.3.1	Rate 9 - Sales	0.0	0.3	(0.3)	0.0	0.0	0.0	0.0	0.0	(0.3)	0.0
1.3.2	Rate 9 - T-Service	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1.3	Total Rate 9	0.0	0.3	(0.3)	0.0	0.0	0.0	0.0	0.0	(0.3)	0.0
1.	Total General Service Sales & T-Service	9 590.3	9 774.0	(183.7)	(239.0)	(32.4)	90.3	189.8	(167.2)	(0.3)	(24.9)
	Contract Sales										
2.1	Rate 100	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2.2	Rate 110	56.3	67.3	(11.0)	(4.6)	0.0 *	0.0	9.5	(15.7)	0.0	(0.2)
2.3	Rate 115	0.0	0.0	0.0	0.0	0.0 *	0.0	0.0	0.0	0.0	0.0
2.4	Rate 135	4.5	1.2	3.3	0.0	0.0	0.0	3.3	0.0	0.0	0.0
2.5	Rate 145	8.6	8.3	0.3	(0.0)	0.0 *	0.0	1.1	(0.7)	0.0	(0.1)
2.6	Rate 170	34.5	35.7	(1.2)	(1.1)	0.0 *	0.0	0.0	0.0	0.0	(0.1)
2.7	Rate 200	169.8	170.8	(1.0)	(1.0)	0.0	0.0	0.0	0.0	0.0	0.0
2.	Total Contract Sales	273.7	283.3	(9.6)	(6.7)	0.0	0.0	13.9	(16.4)	0.0	(0.4)
	Contract T-Service										
3.1	Rate 100	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3.2	Rate 110	732.7	794.2	(61.5)	4.3	(0.1)	4.4	35.3	(102.7)	0.0	(2.7)
3.3	Rate 115	542.8	490.3	52.5	22.8	0.0 *	0.0	34.6	(2.6)	0.0	(2.3)
3.4	Rate 125	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3.5	Rate 135	60.0	59.7	0.3	1.9	0.0	0.0	1.5	(3.0)	0.0	(0.1)
3.6	Rate 145	41.6	55.1	(13.5)	(17.7)	0.0 *	0.0	10.9	(3.3)	(3.1)	(0.3)
3.7	Rate 170	256.7	260.6	(3.9)	1.9	0.0 *	0.0	18.1	(8.9)	(14.5)	(0.5)
3.8	Rate 300	0.0	35.0	(35.0)	0.0	0.0	0.0	0.0	0.0	(35.0)	0.0
3.9	Rate 315	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3.	Total Contract T-Service	1 633.8	1 694.9	(61.1)	13.2	(0.1)	4.4	100.4	(120.5)	(52.6)	(5.9)
4.	Total Contract Sales & T-Service	1 907.5	1 978.2	(70.7)	6.5	(0.1)	4.4	114.3	(136.9)	(52.6)	(6.3)
5.	Total	11 497.8	11 752.2	(254.4)	(232.5)	(32.5)	94.7	304.1	(304.1)	(52.9)	(31.2)

* Less than 50,000 m³.

Witnesses: R. Cheung
M. Suarez

** Less than

The principal reasons for the variances contributing to the weather normalized decrease of 221.9 10^6m^3 in the 2018 Budget over the 2017 Budget are as follows:

1. The volumetric decrease of 134.0 10^6m^3 in Rate 1 is due to lower average use per customer of 200.1 10^6m^3 and partially offset by customer growth of 66.1 10^6m^3;

2. The volumetric decrease of 17.0 10^6m^3 in Rate 6 is due to lower average use per customer of 63.8 10^6m^3, partially offset by customer growth of 24.2 10^6m^3 and the net customer migration from Contract Sales and T-Service of 22.6 10^6m^3;

3. The volumetric decrease of 0.3 10^6m^3 in Rate 9 is due to the loss of six customers;

4. The volumetric decrease for Contract Sales and T-Service of 70.6 10^6m^3 is due to the decreases in the apartment sector of 1.6 10^6m^3, the commercial sector of 13.4 10^6m^3, the industrial sector of 54.6 10^6m^3 and Rate 200 of 1.0 10^6m^3. The decrease is mainly contributed by lost customers of 52.6 10^6m^3 and net customer migration to General Service of 22.6 10^6m^3.

COMPARISON OF GAS SALES AND
TRANSPORTATION REVENUE BY RATE CLASS
2018 BUDGET AND 2017 BOARD-APPROVED BUDGET
($ MILLIONS)

Item No.		Col. 1 2018 Budget	Col. 2 2017 Board-Approved Budget	Col. 3 2018 Budget Over (Under) 2017 Budget (Col. 1-Col. 2)
General Service				
1.1.1	Rate 1 - Sales	1 695.7	1 592.1	103.6
1.1.2	Rate 1 - T-Service	36.5	55.1	(18.6)
1.1	Total Rate 1	1 732.2	1 647.2	85.0
1.2.1	Rate 6 - Sales	876.8	807.0	69.8
1.2.2	Rate 6 - T-Service	155.8	171.2	(15.4)
1.2	Total Rate 6	1 032.6	978.2	54.4
1.3.1	Rate 9 - Sales	0.0	0.1	(0.1)
1.3.2	Rate 9 - T-Service	0.0	0.0	0.0
1.3	Total Rate 9	0.0	0.1	(0.1)
1.	Total General Service Sales & T-Service	2 764.8	2 625.5	139.3
Contract Sales				
2.1	Rate 100	0.0	0.0	0.0
2.2	Rate 110	11.6	12.1	(0.5)
2.3	Rate 115	0.0	0.0	0.0
2.4	Rate 135	0.8	0.2	0.6
2.5	Rate 145	1.7	1.5	0.2
2.6	Rate 170	6.0	5.4	0.6
2.7	Rate 200	29.3	27.8	1.5
2.	Total Contract Sales	49.4	47.0	2.4
Contract T-Service				
3.1	Rate 100	0.0	0.0	0.0
3.2	Rate 110	33.7	35.0	(1.3)
3.3	Rate 115	12.3	8.0	4.3
3.4	Rate 125	10.9	11.7	(0.8)
3.5	Rate 135	1.9	2.4	(0.5)
3.6	Rate 145	1.8	2.1	(0.3)
3.7	Rate 170	2.6	3.3	(0.7)
3.8	Rate 300	0.1	0.2	(0.1)
3.9	Rate 315	0.0	0.0	0.0
3.	Total Contract T-Service	63.3	62.7	0.6
4.	Total Contract Sales & T-Service	112.7	109.7	3.0
5.	Total	2 877.6	2 735.2	142.3

Witnesses: R. Cheung
M. Suarez