OPERATING COST SUMMARY

1. This evidence sets out an overview of Enbridge's 2017 updated forecast operating Costs, which form part of the final 2017 Allowed Revenue.

2. Within EB-2012-0459, the Board approved most of Enbridge's operating cost components for the purpose of setting the Allowed Revenue amounts that would be recovered in rates in each of 2014 through 2018. However, as identified in Appendix E of the EB-2012-0459 Decision and Rate Order, dated August 22, 2014, the following operating cost forecasts, for each of 2015 through 2018, are subject to update in annual rate adjustment applications:

   - Gas costs will be updated as a result of the volumes reforecast and re-determined gas supply plan, and to reflect approved pricing;
   - Customer Care/CIS related O&M costs will be updated in accordance with the Board Approved EB-2011-0226 Settlement Agreement;
   - DSM related O&M costs will be updated annually;
   - Pension and OPEB related O&M costs will be re-forecast annually; and
   - Utility income taxes will be re-forecast annually to reflect impacts to taxable income from updated revenues, gas costs, O&M, and cost of capital.

3. In addition to the adjustments contemplated within Appendix E of the EB-2012-0459 Decision and Rate Order, the 2017 updated forecast operating costs have also been adjusted in accordance with the Board approved 2016 Rate Adjustment proceeding (EB-2015-0114) Settlement Agreement. The Settlement Agreement requires an allocation of base pressure gas and Lost and Unaccounted for gas ("LUF") to Unregulated Storage operations, as a result of the adoption of fully allocated costing for those items.

Witness: R. Small

4. Table 1 below, shows a summary of Enbridge's utility cost of service for each of the 2016 Board Approved (EB-2015-0114), the 2017 placeholder (EB-2012-0459), and the 2017 Updated Forecast operating costs presented within this proceeding.

TABLE 1
OPERATING COST SUMMARY (INCLUDING CIS & CUSTOMER CARE)

Line No.		Col. 1 EB-2015-0114 2016 Total Approved Costs and Expenses ($Millions)	Col. 2 EB-2012-0459 2017 Total Costs and Expenses Placeholder ($Millions)	Col. 3 2017 Total Updated Forecast Utility Costs and Expenses ($Millions)
1.	Gas costs	1,764.8	1,632.5	1,603.1
2.	Operation and maintenance	456.6	436.9	459.9
3.	Depreciation and amortization expense	288.9	297.7	297.7
4.	Fixed financing costs	1.9	1.9	1.9
5.	Municipal and other taxes	45.5	47.9	47.9
6.	Operating costs	2,557.7	2,416.9	2,410.5
7.	Income tax expense (incl. taxes on suff./def.)	23.6	34.1	14.3
8.	Cost of service (excl. interest & return)	2,581.3	2,451.0	2,424.8

5. The numeric impacts of each of the 2017 updated forecast operating cost adjustments are shown in Exhibit D1, Tab 1,
Schedule 2. The tables set out therein show the updates that have been made to each of the operating cost elements listed above (gas costs, customer care/CIS costs, pension/OPEB costs and DSM costs).

6. The evidence with respect to the updated forecast of gas costs can be found at Exhibit D1, Tab 2, Schedules 1 to 11. The overall impact of the adjustment to the placeholder amount is a decrease of $29.4 million. This takes account of the updated 2017 gas volume forecast (inclusive of the allocation of LUF to Unregulated Storage), as well as the July 1, 2016 QRAM prices, and the 2017 gas supply plan.

7. The evidence with respect to the updated 2017 customer care/CIS costs can be found at Exhibit D1, Tab 3, Schedules 1 to 3. The impact of the adjustment to the placeholder amount for 2017 customer care/CIS costs is a decrease of $1.9 million in operating costs.

8. Evidence with respect to the updated forecast DSM costs can be found at Exhibit D1, Tab 4, Schedule 1. The impact of the adjustment to the placeholder amount for 2017 DSM costs is an increase of $28.7 million in operating costs.

9. Evidence with respect to the updated forecast pension and OPEB costs can be found at Exhibit D1, Tab 5, Schedule 1. The impact of the adjustment to the placeholder amount for 2017 pension and OPEB costs is a decrease of $3.8 million in operating costs.

10. A further adjustment to Allowed Revenue each year from 2015 to 2018 is to be made to reflect the updated utility income tax amount. As described within Appendix E to the EB-2012-0459 Final Rate Order, utility income taxes will be re-forecast annually to reflect impacts to taxable income stemming from the updating of revenues, gas costs, O&M and the re-determined approved overall rate of return on rate base. In addition to the impacts resulting from the adjustments described

within Appendix E to the EB-2012-0459 Final Rate Order, the 2017 updated forecast of income tax also reflects impacts resulting from the allocation of LUF and base pressure gas to Unregulated Storage operations, as required per the EB-2015-0114 Settlement Agreement. Evidence with respect to the updated forecast income tax amount can be found at Exhibit D1, Tab 6, Schedules 1 and 2.

11. Enbridge will also incur costs in 2017 related to compliance with Cap and Trade obligations. However, in accordance with direction from the OEB and consistent with the instructions in the EB-2015-0363 Report on the Regulatory Framework for the Assessment of Costs of Natural Gas Utilities' Cap and Trade Activities, Enbridge is not seeking approval of the Cap and Trade Unit Rates (or associated costs) in this Rate Adjustment Application. Instead, the Cap and Trade Unit Rates (as well as necessary additional Variance or Deferral Accounts) will be presented for approval within Enbridge's 2017 Compliance Plan, which is to be filed by November 15, 2016.

COST OF SERVICE
2017 UPDATED FORECAST (INCLUDING CIS & CUSTOMER CARE)

Line No.		Col. 1 EB-2012-0459 2017 Utility Placeholder Costs and Expenses ($Millions)	Col. 2 2017 CIR Update Adjustments ($Millions)	Col. 3 2017 Updated Forecast Utility Costs and Expenses ($Millions)
1.	Gas costs	1,632.5	(29.4)	1,603.1
2.	Operation and maintenance	436.9	23.0	459.9
3.	Depreciation and amortization expense	297.7	-	297.7
4.	Fixed financing costs	1.9	-	1.9
5.	Municipal and other taxes	47.9	-	47.9
6.	Interest and financing amortization expense	-	-	-
7.	Other interest expense	-	-	-
8.	Total costs and expenses	2,416.9	(6.4)	2,410.5

Witness: R. Small

EXPLANATION OF ADJUSTMENTS TO UTILITY COSTS AND EXPENSES
2017 UPDATED FORECAST (INCLUDING CIS & CUSTOMER CARE)

Line No. Adj'd	Adjustments ($Millions)	Explanation
1.	(29.4)	Gas costs
		Adjustment to 2017 placeholder gas costs to reflect the updated 2017 volume forecast (inclusive of the allocation of LUF to Unregulated Storage), gas supply plan, and July 1, 2016 QRAM prices.
2.	23.0	Operation and maintenance

	2017 Update	2017 Placeholder	Change
Pension and OPEB accrual cost update	24.7	28.5	(3.8)
DSM cost update	62.9	34.2	28.7
Customer Care/CIS cost update	102.5	104.4	(1.9)
			23.0

2017 GAS SUPPLY EVIDENCE OVERVIEW

1. The purpose of the D1, Tab 2 series of exhibits is to present the Company's 2017 gas supply evidence and resulting gas costs. The plan and associated documents provide an overview of the gas cost consequences of Enbridge's gas supply activities, including storage and transportation, for the 2017 Fiscal Year.

2. In the Settlement Proposal in the 2016 Rate Adjustment proceeding (EB-2015-0114), Enbridge agreed that:

> In its 2017 rate adjustment application, it will augment the gas supply evidence so that, in addition to the material provided in this proceeding, there is an explanation of the principles driving the gas supply plan, and how those principles are being implemented by the detailed evidence on gas procurement and transportation.[1]

3. In accordance with the Settlement Proposal, Enbridge has expanded and reorganized its Gas Supply evidence for the 2017 filing.

4. The evidence in Exhibit D1, Tab 2 is organized in the following manner:

   a) The Gas Supply Memorandum at Schedule 2 describes the gas supply planning process, including the underlying gas supply planning principles;
   b) Schedule 3 explains how the gas supply planning principles were applied to the 2017 test year and provides an overview of the gas cost consequences of the Company's 2017 gas supply activities;
   c) Supporting schedules detailing Enbridge's 2017 gas supply arrangements, and associated costs and volumes are found at Schedules 4 through 10;

[1] EB-2015-0114, Exhibit N1, Tab 1, Schedule 1, Page 9

d) Schedule 11 outlines future developments in the North American natural gas market currently being monitored by the Company.[2]

5. The Company acknowledges that there will likely be changes to the way that gas supply evidence is presented in future proceedings, as an outcome from the Distributor Gas Supply Planning Consultation (EB-2015-0238) and the update to the Filing Requirements for Natural Gas Distributor Rate Applications proceeding (EB-2016-0033. In a Report to the Board as part of EB-2015-0238, Board Staff issued recommendations for future processes that would consider and approve a five year framework as well as annual gas supply plans for Enbridge and Union Gas. The Board Staff Report suggests that further information about what is to be included in filings for these new processes will be forthcoming. Enbridge looks forward to working with Board Staff and stakeholders to determine the scope, content and timing of future gas supply filings and proceedings. In the meantime, Enbridge's evidence in this case does not try to anticipate what will be required in future proceedings.

[2] The Company emphasizes that the overview of future supply considerations in Schedule 11 has been created on a best efforts basis, is subject to change and is not a request for preapproval.

Gas Supply Memorandum

Witnesses: M. Kirk
D. Small

Contents

1. Introduction

The purpose of this evidence is to provide an overview of the Enbridge Gas Distribution ("Enbridge" or "the Company") gas supply planning process. The Company considers all of the information herein when developing its test year gas supply plan, the results of which for 2017 – including supply, transportation and storage sources and costs – can be referenced in Exhibit D1, Tab 2, Schedules 3 through 10.

The objective of gas supply planning is to develop a portfolio of natural gas supply, transportation, and storage assets that provide for the safe, reliable, and cost effective delivery of natural gas to customers.

Enbridge is the largest natural gas Local Distribution Company ("LDC") in Canada, providing natural gas distribution services to over 2 million customers located in the Greater Toronto Area ("GTA"), the Niagara Peninsula, Barrie, Midland, Peterborough, Brockville, Ottawa, Gatineau (via Gazifère Inc.), and other Ontario communities (collectively the "Enbridge System").

A gas supply plan is unique to every LDC. Climate and weather seasonality, population and customer makeup, and access to natural gas production basins and supply hubs, all of which stem from the geographic location of the Enbridge System, have an impact on the Company's gas supply plan. As such, specific details on Enbridge and its franchise area must be understood in order to comprehend its gas supply plan.

The Enbridge System is divided into two distinct regions for gas supply planning purposes: The Eastern Delivery Area ("EDA")[1], containing Brockville, Ottawa, Gatineau and the surrounding area; and Central Delivery Area ("CDA")[2], containing the GTA, the Niagara Peninsula, Barrie, Midland, Peterborough, and the surrounding area.

Climate and Customer Makeup

The GTA and Ottawa regions are two of the most densely populated areas in Canada and a vast majority of residential homes in both regions use natural gas for home and water heating. The prevalence of natural gas in homes is partially due to the density in those areas which provides a lower cost to serve customers, and partially due to the competitive price of natural gas in the province as compared to other fuel options, such as electricity. This fact is evident in the Company's customer makeup, as over 90% of Enbridge's 2+ million customers are residential customers. While residential customers tend to use gas consistently throughout the year for water heating, the bulk of their usage is for space heating in the winter. The seasonal consumption profile of residential customers is amplified by the seasonal weather patterns experienced in the Enbridge franchise area (i.e., cold winters and hot summers).

[1] The EDA contains the "Eastern Weather Zone" for gas supply planning purposes.
[2] The CDA contains the "Central Weather Zone" and "Niagara Weather Zone" for gas supply planning purposes.

Pairing this largely residential customer base with especially seasonal weather patterns has a dramatic impact on gas consumption. On the day of peak consumption, Enbridge customers consume a volume equal to more than 3 times the daily average consumption volume, and approximately 9 times the volume of gas on a day of low (i.e., baseload) consumption.[3] Enbridge's customers have a number of service options. The gas supply implications of the service options are important considerations for planning purposes. Summary information about Enbridge's customer types is found at section 4 of this Memorandum.

Each LDC has its own unique characteristics. The simplest comparisons to the Enbridge System are two nearby utilities that experience similar weather seasonality: Union Gas Limited ("Union Gas"), in south and northern Ontario; and Gaz Métro, in Montreal and surrounding areas. Though the region experiences the same weather seasonality, the population density in Union Gas' franchise area is far less than that served by Enbridge and, as a result, Union Gas has fewer residential customers spread across larger delivery areas. In addition, Union Gas has a higher percentage of industrial customers on its system. Alternatively, the population in Gaz Métro's franchise area – particularly in Montreal – is a closer match to that of Enbridge, but the market penetration of natural gas use for home and water heating is significantly lower due to the competitive price of electricity in Québec, resulting in a lower concentration of residential customers on the Gaz Métro system as compared to Enbridge.

These climate and customer makeup differences emphasize why there is no one-size-fits-all solution to gas supply planning.

Access to Natural Gas Supply

Another impact defined by the geographic location of the Enbridge System is access to natural gas production basins. Enbridge does not have access to any significant local natural gas production within or proximate to its franchise area, with less than 1% of its annual gas supply requirement locally produced within Ontario. Enbridge also has limited access to natural gas storage assets within its franchise area[4]. In order to provide safe, reliable, and cost effective distribution of natural gas to its customers, Enbridge procures supply from basins and liquid hubs around North America. These supplies are transported to the markets served by Enbridge through contracted capacity on several upstream natural gas transmission systems that ultimately connect to the Enbridge franchise area and storage facilities in southwestern Ontario.

[3] Weather-normalized peak day consumption is approximately 4,000 TJ/d while baseload is approximately 430 TJ/d, and average consumption is approximately 1,200 TJ/d.
[4] Enbridge owns storage facilities at Tecumseh, near Corunna in southwestern Ontario and at Crowland in the Niagara Region; Enbridge also contracts for third party storage.

2. Gas Supply Planning Cycle

The Enbridge gas supply plan is developed and assessed using four gas supply planning principles:

- *Reliability* – As the "supplier of last resort", Enbridge mitigates delivery interruption by sourcing supplies from established liquid hubs and transporting to the Enbridge franchise area on firm transportation contracts;
- *Diversity* – Enbridge mitigates reliability and cost risks by procuring supplies from multiple procurement points and transporting supplies to market and/or storage through several different paths;
- *Flexibility* – The Company manages shifting demand requirements through differentiated supply procurement patterns and provides operational flexibility through service attributes and contract parameters; and
- *Landed Cost* – Enbridge balances gas supply costs with the other principles and ensures low cost natural gas supply for customers.

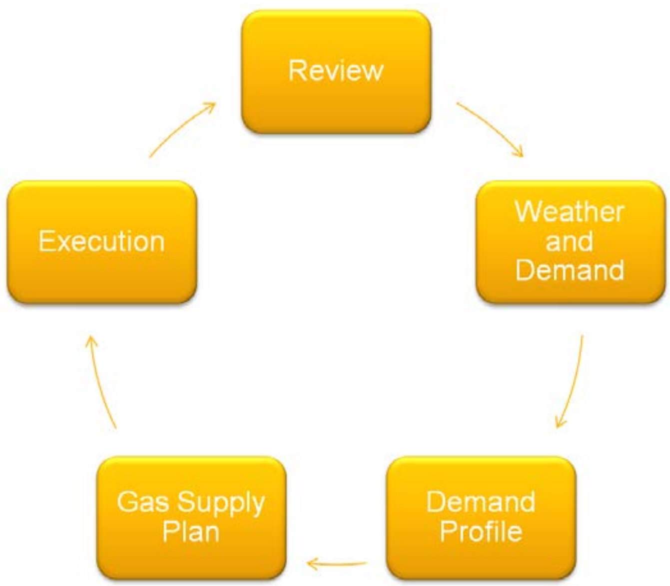
Enbridge's gas supply plan is developed through an iterative process, where information, plans and commitments from past years are considered and updated to accommodate supply requirements for the coming year (the test year). As described in the following paragraphs, some steps in the gas supply planning process are commenced well in advance of the test year while others occur closer to the test year. A flow chart setting out more detail about steps followed in the gas supply planning process is attached as Appendix C to this exhibit.

Prior to developing a gas supply plan for a test year, Enbridge conducts an annual design day and baseload day demand analysis over a five year planning horizon with the primary focus being the first two years. The main purpose of these analyses is to determine the expected demand in future years, in order to evaluate the renewal, addition, and shedding of transportation and/or other market-based solutions to meet that demand. In the flow chart of the gas supply process provided as Appendix C, these analyses occur in the Energy Supply and Policy row, under the 3 Years Prior column.

Enbridge develops the test year gas supply plan over a two year planning horizon with the primary focus being on the first year. The two year planning horizon ensures that a complete storage management cycle is taken into account as the gas supply plan is developed. The primary focus is on the first year to correspond with the annual rate application that is filed with the Ontario Energy Board (the "Board"). In the flow chart at Appendix C, these developments occur in the Energy Supply and Policy row, under the 2 Years Prior column.

The planning horizon to develop the test year gas supply plan spans approximately nine months. This is an intensive process which is initiated with the development of a demand forecast (discussed in Section 2.2) that traditionally begins in February. The establishment and execution of the gas supply plan for the test year is summarized in Figure 1 as a cycle of phases, each of which is described below. These steps are also described in the flow chart at Appendix C, in all three rows under the 1 Year Prior column. The outputs and cost consequences of the test year gas supply plan are filed with the Board as part of the annual rate application, typically in late summer or early fall.

Figure 1: Gas Supply Planning Cycle



2.1 Review

The cycle begins with a review of recent actual and expected future market conditions. As mentioned in Section 1, less than 1% of the Company's annual gas supply requirement is locally produced within Ontario, while the rest needs to be procured from various basins and liquid hubs throughout North America. The North American natural gas market is evolving at a rapid pace, constantly creating new procurement opportunities. Therefore the Company begins its annual gas supply planning cycle by reviewing short and long-term market conditions.

For 2017, near term market conditions are addressed in Exhibit D1, Tab 2, Schedule 3 "Gas, Transportation and Storage Costs", while future market considerations are addressed in Exhibit D1, Tab 2, Schedule 11 "Gas Supply Future Considerations".

2.2 Weather and Demand

Before developing a gas supply plan, a forecast of natural gas demand for the coming test year is required. This annual demand forecast must then be understood in the context of the expected demand profile of its customers. For example, as previously mentioned, residential customers make up over 90% of the Enbridge System in terms of customer count. However, an individual residential customer does not consume as much gas, on average, as compared to a commercial or industrial customer. Residential customers are temperature sensitive and consume significantly more gas in the winter than in the summer. Commercial customers tend to follow a similar consumption profile to residential customers, but most industrial customers use gas as part of their operations, and do so in a much more consistent manner over the course of the year.

Annual demand is largely a function of forecasted weather conditions. The Company's Economics & Business Performance department determines the budget weather, measured in terms of heating degree days ("HDD") [5], using separate Board approved methodologies by weather zone which include:

- Central – 50% based on a 10-year moving average and 50% based on a 20-year trend forecast;
- Eastern – de Bever with trend regression considers 5 year weighted averages within a weather cycle; and
- Niagara – 10 year moving average.

The annual forecast methodology for budget demand takes into consideration the volumetric impacts of Demand Side Management and Unaccounted for gas forecasts and assumes no migration of customers between Direct Purchase and Sales service. The Company's Economics & Business Performance department works with the Large Volume Customer Strategy department to determine the annual budget demand by customer type as follows:

- General service budget demand forecast based on average use regression analysis and projected number of customers; and
- Contract market budget demand forecast based on grass roots approach for existing customers and probability-weighted approach for expected customers.

The annual demand budget and HDDs are provided to the Company's Energy Supply and Policy department, where development of the gas supply plan for the upcoming test year can begin. In the flow chart at Appendix C, these steps occur under the 1 Year Prior column in the "Economics and Business" and "Large Volume Customer Strategy" rows. Further information on the demand budget is filed at Exhibit C1, Tab 2, Schedule 1, "Gas Volume Budget".

[5] A heating degree day is a statistic measuring a given day's average temperature in the number of degrees below a base temperature. In the case of the Ontario natural gas industry, 18 degrees Celsius is used as the base temperature and any degree below 18 degrees Celsius is recorded as a heating degree day. For example, a day on which the average temperature is -2 degrees Celsius would be measured as 18 – (-2) = 20 heating degree days.

2.3 Demand Profile

In the demand profile phase, Board approved Design Criteria are used to distribute the annual demand budget into a daily demand profile.[6] In the flow chart at Appendix C, these steps occur under the 1 Year Prior column in the Energy Supply and Policy row.

For a natural gas utility, Design Criteria refer to one or more statistical or probabilistic conditions and assumptions about weather – usually in the form of HDDs – used to develop gas supply plans to meet forecast utility demand. Probabilistic conditions are used in order to account for the risk of an extreme weather event or multiple extreme weather events occurring. For gas utilities in cold climates with temperature sensitive loads, such as Enbridge, developing natural gas supply plans to meet expected winter demand including the crucial peak day, or day of highest demand, is extremely important. Peak day demand is derived from the HDDs for peak day assumed within the Design Criteria. Failing to assume an appropriate level of demand on peak day exposes a utility's gas supply plan to the risk of needing to procure high priced supply on short notice, or not being able to meet demand as a result of not contracting for sufficient transportation and storage capacity or ensuring appropriate levels of gas in storage.[7] The inability to meet peak day demand can result in low distribution system pressure or, in extreme cases, system outages along with the economic implications of not having natural gas available for consumption.

Utility Design Criteria generally fall into one of the following two categories:

1) Single Peak Design Criteria, which incorporates statistical conditions about weather applied to a single day, namely, the peak day. Accordingly, developing a gas supply plan based on peak day alone becomes the most important element in supply planning; or
2) Multi-Peak Design Criteria, which, in addition to incorporating the crucial single peak day weather criteria, include statistical conditions about weather applied to other days in the winter season.

The statistical conditions associated with Design Criteria can range from a predetermined recurrence interval to the coldest day on record for the service area or areas in which a utility operates.

A recurrence interval is defined as the average frequency, in years, in which an actual weather event or HDD level is expected to exceed that of the design level one time. For example, a 1 in 10 recurrence interval would mean that the HDD level assumed on peak day is expected to be exceeded once every ten years. Another way to express this statement is that there is a 10% probability that the specified

[6] Much of the information in this section appears in the pre-filed evidence and Settlement Agreement to EB-2011-0354 (Exhibit D1, Tab 2, Schedule 3).
[7] Specifics on how Enbridge utilizes storage is discussed in Section 3.3.

peak day HDD value would be exceeded in any given year. All else equal, the longer the recurrence interval, the higher the peak day HDD assumption in a given year, and the more conservative the gas supply plan.

If the coldest day method is utilized, the peak day HDD value is selected by choosing the coldest day on record and utilizing this HDD value to derive peak day demand that is used to establish the gas supply and transportation portfolio.[8]

The level of risk, as measured by the recurrence interval assumed in the Design Criteria, has a significant impact on the development of the demand profile and, subsequently, the gas supply plan. A more conservative level of risk (i.e., a longer recurrence interval) produces a gas supply plan that requires higher upfront budget costs to procure storage and transportation assets but it also mitigates the need for higher costs when executing the gas supply plan should actual demand exceed budgeted demand, reducing price volatility on customer bills. The converse is true when a less conservative approach (i.e., a shorter recurrence interval) is used to develop the gas supply plan. Figure 2 provides a qualitative assessment of cost impacts on a gas supply plan resulting from different levels of risk assumed in the Design Criteria.

Figure 2: Design Criteria Risk Matrix

Design Criteria	Demand Variance Above Budget	
	Minimal	High
Risky	Low Budget Cost Neutral Execution Cost	Low Budget Cost High Execution Cost
Conservative	High Budget Cost Neutral Execution Cost	High Budget Cost Low Execution Cost

The Company's current Design Criteria utilize a 1 in 5 recurrence interval and 18 multi-peaks (including peak day) representing the coldest temperatures that are expected to occur over the winter season of

[8] Note that the recurrence interval method can produce the same result as the coldest day method by picking a recurrence interval sufficiently long, according to underlying distribution assumptions, so as to match the resultant HDD value to the coldest day on record HDD value.

the planning period, covering January through to the end of March. Multi-peaks are developed for each of the Central, Eastern and Niagara regions of Enbridge's franchise area.

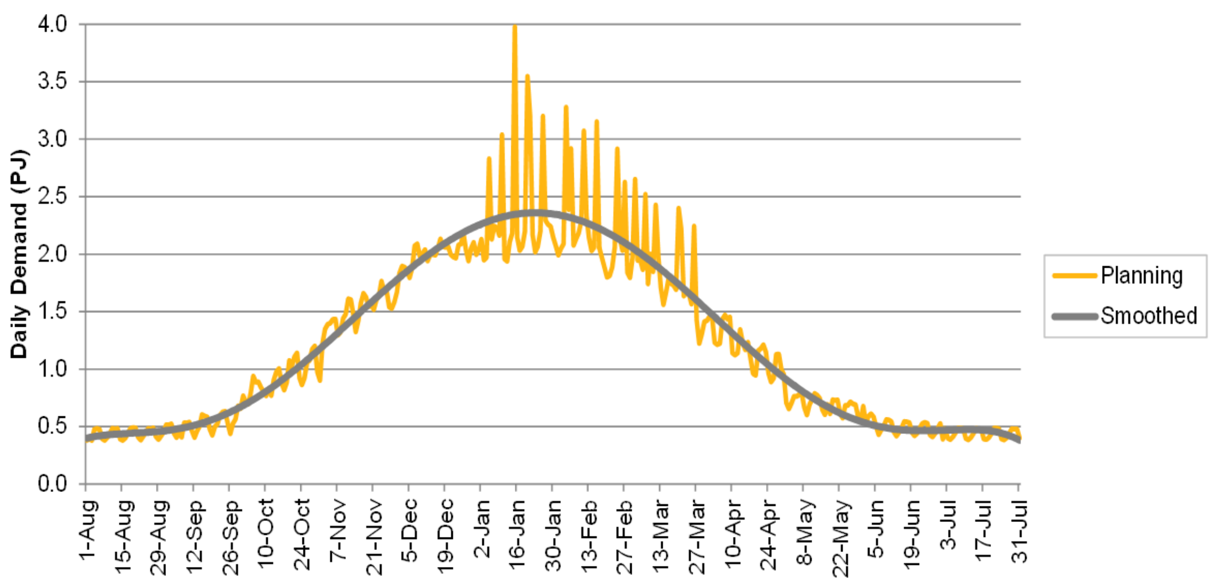
When the daily HDDs are plotted on a graph, they show a seasonal pattern typical of cold winters and warm summers. With respect to the multi-peak weather conditions, the curve that most closely represents the temperature data is a lognormal distribution. The 18 multi-peaks in the current Design Criteria correspond to a recurrence interval of 1 in 5 years and are derived assuming a lognormal distribution of degree days.

Table 1 below shows the peak day HDD values used in the current peak day Design Criteria for each region. Figure 3 illustrates a representative aggregate daily demand profile used in developing the gas supply plan.

Table 1
Peak Day HDD Value for Each Region under Existing Design Criteria

Central Weather Zone	Eastern Weather Zone	Niagara Weather Zone
41.4	48.2	38.8

Figure 3: Illustrative Daily Demand Profile



The demand profile in Figure 3 represents an illustrative example of natural gas demand on the entire Enbridge system. It is an amalgamation of demand from residential customers, commercial businesses and institutions, and large and small industrial facilities. Every customer has its own profile and they vary dramatically across customer classes. A residential customer profile is typically the “peakiest”, with demand in winter most impacted by weather. Alternatively, an industrial customer using natural gas as part of its day-to-day operations may be un-phased by weather and have a completely flat profile all year. These varying profiles are often described in terms of “load factor”, a statistic measuring average demand as a percentage of peak demand. In the examples above, an industrial customer using natural gas consistently throughout the year would have a very high load factor, since its average consumption would be nearly equivalent to its peak consumption. Residential customers typically have very low load factors since their low summer demand contributes to lower average annual demand. Load factors and demand profiles of various customer classes are important to understand, but a gas supply plan is ultimately designed for the system as a whole, and in accordance with the overall demand profile illustrated in Figure 3.

2.4 Gas Supply Plan

Once the demand profile is established, the gas supply plan can be developed. The gas supply plan includes a portfolio of natural gas supply, transportation, and storage assets required to meet demand and a plan for how those assets will be utilized over the gas supply planning period. The portfolio is designed, first and foremost, to meet demand for natural gas on peak day. Once the Company has contracted for the assets required to meet peak day demand, the Company optimizes the use of those assets in meeting seasonal demand for natural gas throughout the winter and summer months. In the flow chart at Appendix C, these steps occur under the 1 Year Prior column in the Energy Supply and Policy row. The gas supply portfolio and how the portfolio will be utilized over the year is developed and assessed using the four gas supply planning principles discussed in the introduction to Section 2.

Transportation Portfolio

The assessment of the transportation portfolio typically occurs 3 years prior to the test year over a 5 year planning horizon. The first year of the 5 year planning horizon includes the current year with an emphasis placed on the next 2 years. The lead time and planning horizon provide the Company with sufficient time to assess its transportation requirements and comply with the 2 year renewal notice typically required by transportation providers for existing transportation capacity and the 3 year notice typically required for new transportation capacity. Transportation contract terms typically range from 1 to 5 years for existing capacity and 15 to 20 years for new capacity.

The transportation capacity is assessed through design day demand and baseload day demand analyses for the EDA and CDA regions. The objective of this assessment is to ensure that sufficient transportation capacity is available to meet the forecasted design day and baseload demand requirements. As part of this assessment, the Company will also identify what volume of Delivered Service and Peaking Supplies are required to balance the design day demand requirements. Once the transportation capacity requirements are identified, the specific transportation paths are assessed through a review of existing and new transportation service attributes using a balanced application of the gas supply planning principles. The attributes that are assessed and used in the gas supply planning process include receipt point(s), delivery point(s), contract demand, start date, expiry date, tolls, and fuel ratios. Details on Transportation services typically contracted for by Enbridge are provided in Section 3.2.

Storage Portfolio

The assessment of the storage portfolio typically occurs 2 years prior to the test year over a 5 year planning horizon. The first year of the 5 year planning horizon includes the current year with an emphasis being placed on the following year. Unlike the transportation capacity requirements, the total storage capacity used for gas supply planning remains relatively unchanged from year to year. The Company maintains 98 PJ of underground storage at Tecumseh near Corunna in southwestern Ontario and at Crowland near Welland in the Niagara Region in addition to approximately 25 PJ of third party storage capacity with varying contract terms that typically require 1 year renewal notice. The assessment is focused on a review of the third party storage agreement attributes in accordance with the gas supply planning principles. The third party storage agreement attributes that are assessed and used in the gas supply planning process include the total capacity, the deliverability, and the contract term. Further details on Storage Assets utilized by Enbridge are provided in Section 3.3.

Gas Supply Portfolio

The assessment of the gas supply portfolio typically occurs 1 year prior to the test year and corresponds with the development of the utilization plan for the transportation and storage portfolios. The assessment takes into consideration the natural gas commodity price forecasts for supply hubs connected to the receipt points associated with the transportation portfolio using monthly natural gas forward curves from independent third parties (i.e., NGX and Kiodex) for a 21 day average settlement price for each forward contract month. Supply sources utilized in the Company's gas supply plan are outlined in Section 3.1.

Portfolio Evaluation

The portfolio of transportation and storage and gas supply assets in the gas supply plan is developed in order to meet peak day natural gas demand. Once the assets required to meet peak day natural gas demand have been acquired, the portfolio is optimized to meet annual and seasonal demand. The key principle applied in the optimization process is landed cost – Enbridge evaluates and determines which assets should be used throughout the year to achieve the lowest cost outcome.

For the purposes of balancing the gas supply portfolio cost with the other gas supply planning principles, the gas supply portfolio is evaluated through an iterative process using a modeling application called SENDOUT. Enbridge uses SENDOUT, a software program provided by ABB Inc., to determine the optimal use of its existing gas supply portfolio of resources to meet projected demand requirements. Any solution provided by SENDOUT is achieved by satisfying the objective function of minimized portfolio costs. SENDOUT is capable of simultaneously evaluating thousands of time-dependent constraints across a forecast period.[9]

The result of this process is a gas supply plan that:

- Identifies the planned procurement of supply at all available supply basins/hubs; and
- Identifies the planned injection and withdrawal volumes, storage balances, and costs for all storage facilities and contracts on a daily basis pursuant to injection and withdrawal parameters and storage contract parameters.

Gas Costs & Budgets

Once the monthly supply portfolio and storage targets have been established, gas costs can be calculated. Enbridge currently purchases all of its gas on an indexed basis, meaning the price is set relative to the price at a particular hub, over a particular period of time (for example, the price could be set relative to the daily spot price or the average price over a month).

Price assumptions reflect the market's assessment (at the time evidence is prepared) of the various expected receipt points in the Company's gas supply plan. The market's assessment can be determined at any point in time by the use of a simple average of forward quoted prices as reported by various media and other services, over a period of 21 business days for a basket of pricing points and pricing indices that reflect the Company's gas supply acquisition arrangements.

Any variance between the actual commodity cost and the forecasted prices is captured in the Purchased Gas Variance Account ("PGVA"). Any variation in the forecasted transportation tolls and the actual tolls is also captured in the PGVA. The balance of the PGVA is cleared to customers through a volumetric line item, calculated on a rolling 12-month basis and updated each quarter. Details on the PGVA are filed in the Rate Design evidence of each Quarterly Rate Adjustment Mechanism Filing ("QRAM").

The cost consequences of the 2017 gas supply plan are produced in Exhibit D1, Tab 2, Schedule 3 "Gas Transportation and Storage Costs".

2.5 Execution

Once the gas supply plan is established, the execution phase of the cycle takes place.

Transportation capacity is typically acquired directly from pipelines or through open seasons for new and existing capacity posted by transportation service providers. In the case of new capacity requiring

[9] Information on the SENDOUT software can be found at the ABB website: http://new.abb.com/enterprise-software/energy-portfolio-management/commercial-energy-operations/sendout.

new assets to be constructed, this will result in binding precedent agreements that are negotiated between Enbridge and the transportation provider. When the transportation capacity goes into service, the precedent agreement is superseded with a gas transportation agreement that has been negotiated between Enbridge and the transportation provider.

Enbridge procures natural gas supply at various points in time leading up to and during the execution of the gas supply plan in accordance with its Natural Gas Procurement Policies and Procedures. The procurement of supply is initiated leading into the start of each year. Since, at the start of the year, it is not known if actual demand will be less than budget demand, only a portion of the total supply requirement is purchased at that time. The supply is purchased through a Request for Proposal process based on a combination of annual and seasonal terms.

Leading into each month, the supply requirements are re-evaluated based on the level of demand that has been experienced, the level of supply that has been procured, and other factors influencing short and medium term demand. If additional supply is required for the upcoming month, it will be procured on a monthly basis through a Request for Proposal process, electronic trading systems (i.e. NGX) or directly from approved suppliers.

Decisions related to the execution of the gas supply plan are made during operational planning meetings that are typically conducted on a weekly basis during the winter season and bi-weekly during the summer season. These meetings are held more frequently if required. Operational planning meetings are overseen by the Director of Energy Supply and Policy and include a diverse cross-functional team represented by Gas Supply Planning, Gas Supply Procurement, Gas Costs and Budgets, Gas Control Operations, Gas Storage Operations, Distribution Planning, and Large Volume Customer Strategy.

Operational planning meetings take into consideration:

- Actual and budget year-to-date variances in weather and demand;
- Short term (7 day) and medium term (approximately 45 days) weather forecasts;
- Revised gas supply plan outlook that takes into account actual and short term demand forecast;
- Operational updates from Gas Control and Gas Storage;
- Procurement strategies; and
- Balancing requirements for Direct Purchase customers.

Periods of peak or near peak day demand are typically managed through:

- Utilization of peaking services; and
- Curtailment of customers on interruptible distribution services.

Periods of forecasted long term higher demand than budget are typically managed through:

- Incremental procurement of supply, typically on a month ahead basis, at the most economical supply hubs/basins that correspond with unutilized transportation capacity; and
- Withdrawing from storage balances allocated to maintain incremental deliverability targets.

Periods of forecasted long term lower demand than budget are typically managed through:

- Reduced procurement of supply at least economical supply hubs/basins; and
- Unutilized transportation capacity released to the secondary market to reduce UDC costs.

Enbridge reports on the execution of its gas supply plan through various processes defined by the Board. These include QRAM applications, the annual Incentive Regulation Stakeholder Day, the annual deferral account disposition proceeding (which includes the Earnings Sharing Mechanism) and the annual rate adjustment proceeding.

3. Gas, Transportation and Storage Sources

With the lack of local natural gas production within its franchise area, Enbridge has long relied upon acquiring natural gas from various basins in North America and transporting this gas to its franchise area. The manner in which natural gas is delivered to the Company's franchise area is explored in the following three sections: Section 3.1 discusses the various basins and hubs where Enbridge typically acquires natural gas; Section 3.2 describes the transportation paths and services Enbridge employs to transport gas to the franchise area; and Section 3.3 discusses the Company's utilization of storage assets to balance seasonal swings in demand.

3.1 Gas Supply Sources

The following sub-sections outline the gas supply sources typically utilized by Enbridge in its gas supply plan. The sources correspond to those listed elsewhere in the Company's evidence, particularly Exhibit D1, Tab 2, Schedule 5, Page 1 "Summary of Gas Costs to Operations".

3.1.1 Western Canadian Supplies

Historically, the most prevalent source of natural gas for Enbridge has been the Western Canadian Sedimentary Basin ("WCSB"), which spans most of Alberta as well as parts of British Columbia and Saskatchewan. The Company refers to WCSB sources as supplies acquired at Empress, Nova Inventory Transfer ("NIT"), and the Alliance Canadian Receipt location. These supplies are then transported to Ontario via long haul transportation contracts.

The Empress delivery point to the TransCanada PipeLines Limited ("TCPL") Mainline is near the border of Alberta and Saskatchewan. Gas purchased at Empress is delivered on the TCPL Mainline to both the

Enbridge CDA and Enbridge EDA. A further description of the TCPL Mainline is provided in Section 3.2, Transportation.

NIT, also commonly referred to as the Alberta Energy Company ("AECO"), is a point notionally located in the center of the Nova Gas Transmission pipeline system in Alberta. AECO purchases are transported on the Nova Transmission system to Empress, and onwards to the Enbridge franchise area via the TCPL Mainline.

Alliance Canadian Receipt location ("CREC") supply presents an alternative to Empress and AECO for procuring WCSB natural gas. This supply can be transported on the Alliance Pipeline to the Chicago Market Hub where it meets the Vector Pipeline. The Company does not currently procure Alliance supplies.

3.1.2 Peaking Supplies

Peaking contracts source gas from third-party suppliers for delivery to Enbridge during the winter season. These supplies are required for only a few days per year (contracts are typically for a maximum of 10 days per year) but are traded at a premium to supplies committed to for lengthier periods. The agreed upon supply is available to Enbridge on the days the Company chooses to call on the service. When called, these supplies are delivered by a third party directly to the Enbridge franchise areas.

3.1.3 Ontario Production

Gas produced locally within Ontario is de minimus in relative terms.

3.1.4 Chicago Supplies

The central location of the Chicago Hub allows connection to several major gas production regions including Alberta and the Gulf of Mexico, making it another liquid natural gas hub accessed by Enbridge. Gas procured at the Chicago Hub is transported to the Dawn Hub on Vector Pipeline, where it can be stored or continue its flow to the Enbridge franchise area on the short haul paths described in Section 3.2.

3.1.5 Dawn Supplies

Dawn is connected to the largest underground storage facility in Canada and one of North America's most liquid natural gas trading hubs. Its proximity to the Enbridge franchise area as well as its direct access to natural gas supply basins makes it an integral part of the Enbridge gas supply plan. Gas acquired at Dawn is transported to the Enbridge franchise area on transmission pipelines owned and operated by Union Gas, TCPL, and Enbridge. The Company also stores gas at the Dawn Hub and nearby in Michigan and Tecumseh, adding flexibility for gas delivered to Dawn throughout the year.

3.1.6 Niagara Supplies

The Niagara and Chippawa points near the Canadian border with the United States are utilized by Enbridge to import natural gas from shale plays such as the Marcellus basin[10]. Previously an export point for natural gas from Canada to the United States, gas started flowing north into Canada at Niagara in November 2012[11]. In its 2015 Rate Application (EB-2014-0276), Enbridge included the Niagara interconnect on TCPL as a receipt point for the first time, with 200,000 GJ per day of supply effective November 1, 2015.

The Niagara and Chippawa points are close and well connected to the Enbridge CDA and Company storage facilities near the Dawn hub. Gas procured at these points can be transported to the Enbridge franchise area or storage facilities, using transmission pipelines owned and operated by TCPL and Union.

3.1.7 Link Supplies

Enbridge procures gas at a point referred to as "MichCon Generic", part of the DTE Energy system in and around Detroit, Michigan. Gas delivered to MichCon Generic is transported on the Vector and Link pipelines to Dawn and Tecumseh, respectively.

For the purposes of Enbridge's gas supply exhibits, these supplies are referred to as "Link Supplies".

3.1.8 Dominion Supplies

As seen in Appendix B, shale gas basins are spread across the continent, with some of the largest plays located in the United States northeast, such as the Marcellus and Utica basins. The development of infrastructure connecting these basins to the Enbridge franchise area is in the early stages, with several projects in progress.[12] Most relevant to Enbridge is the NEXUS Gas Transmission Project ("NEXUS"), a proposed 1.5 bcf per day natural gas transmission pipeline that will connect to the Vector Pipeline and allow for delivery to Dawn. This project is further discussed in Section 3.2.5.

3.1.8 Delivered Service

Delivered Service refers to contracts with third-party providers typically used throughout the winter season to balance increased seasonal demand. Depending on the arrangement made with the supplier, these supplies can be delivered to Dawn or directly into the CDA or EDA.

[10] Appendix B displays shale basins around North America; Marcellus is in the northeast United States
[11] https://www.neb-one.gc.ca/nrg/sttstc/ntrlgs/rprt/archive/ntrlgssmmr/2012/smmry2012-eng.html.
[12] Exhibit D1, Tab 2, Schedule 11 covers projects Enbridge is following in the United States northeast.

3.2 Transportation

Historically, Enbridge has contracted for capacity on all of the pipelines described in the supply discussions above, including: TCPL, Alliance, Vector, Union, Link, and NEXUS[13]. To maintain diversity and flexibility, Enbridge acquires contracts with varying durations, capacities, and paths. Different paths include long haul (for example, Empress to the Enbridge franchise area) or short haul (for example, Dawn to the Enbridge franchise area). For all transportation contracts, Enbridge pays a demand toll – a fixed monthly charge applied to the Contract Demand (i.e., the reserved capacity on the pipeline) that does not vary according to actual utilization. Some pipelines include a volumetric charge (usually small) and may have other charges such as abandonment charges. Specifically, all TCPL Mainline services contracted for by Enbridge are subject to an abandonment surcharge, and shippers must provide fuel in kind based on posted monthly fuel ratios.

Most transportation contracts are for Firm Transportation ("FT") service (i.e., highest priority service) throughout the year while other contracts may provide service on a seasonal basis. Contracts that are firm for the entire year present challenges to the gas supply process since Enbridge customers demand significantly more natural gas in the winter than in the summer. To ensure adequate transportation capacity is available to meet peak day demand, the Company acquires a high-level of FT service as part of its portfolio. However, this FT capacity could go unutilized in the summer period when demand is lower. This concept, called "Unabsorbed Demand Charges," is an important consideration in transportation and storage planning.

Another consideration in transportation planning is a requirement that Enbridge nominate its transportation contracts within +/- 2% of the Company's demand on a daily basis, or be subject to Limited Balancing Agreement ("LBA") penalty charges on the TCPL and Union Gas transmission systems. Avoiding LBA charges requires the Company's Gas Control team to ensure sufficient volumes are nominated over the course of the day. Nominations are made in accordance with the North American Energy Standards Board ("NAESB") standard nomination cycles, which include five nomination windows. Two windows, at 1:00pm and 6:00pm, are used to nominate gas for delivery at the start of the next gas day (9:00am the following morning); three windows, at 10:00am, 2:30pm, and 7:00pm, are intraday windows used to nominate gas to be delivered later in the same gas day[14]. Additional windows exist for Storage Transportation Service and Firm Transportation Short Notice, described in 3.2.1.

The following sub-sections outline the transportation paths typically utilized by Enbridge in its gas supply plan. These paths correspond to those listed elsewhere in the Company's evidence, particularly Exhibit

[13] NEXUS contract is a precedent agreement only.
[14] All times in Central Standard Time.

D1, Tab 2, Schedule 9, Page 1 (“Status of Transportation & Storage Contracts”) and Exhibit D1, Tab 2, Schedule 5, Page 1 (“the Summary of Gas Costs to Operations”).

3.2.1 TCPL

The 14,101 km TCPL Mainline transports natural gas from Empress (near the Alberta/Saskatchewan border), through the prairies, north of the Great Lakes, and branches off into two lines which form two sides of what is known as the “Eastern Triangle”. One branch is directed south towards the Enbridge CDA; the other continues east towards the Enbridge EDA and into Québec. The remaining side of the triangle connects to the Mainline near the Enbridge CDA in the west and near the Enbridge EDA in the east, running parallel to the Canadian border with the United States between the two points.

TCPL also has Transmission by Others (“TBO”) agreements with Union Gas in Ontario, in the future with Enbridge in Ontario, TransQuébec & Maritimes Pipeline in Québec, and the Great Lakes Gas Transmission Limited Partnership (“GLGT”) – a pipeline that connects with the Mainline near Emerson, Manitoba in the west and St. Clair, Ontario, near the Dawn Hub, in the east.

The TCPL Mainline and GLGT are both displayed as blue lines on the map in Appendix C, with the Mainline running north of the Great Lakes and the GLGT south of the Great Lakes.

The following is a list of services Enbridge has historically contracted for through TCPL.

<u>Long Haul Firm Transportation</u>

Enbridge contracts for long haul FT service with a primary receipt point of Empress and primary delivery point of the Enbridge CDA, Enbridge EDA, or Iroquois[15]. The flexibility of FT service allows for optimization through diversions (i.e., delivery to a delivery point different from the contracted delivery point) and assignments (i.e. the release of contracted transportation capacity to a third-party). These attributes provide for UDC mitigation if required.

<u>Short Haul Firm Transportation</u>

The Company contracts for short haul FT service on a variety of paths with primary receipt points of Dawn, Parkway[16], and Niagara; and primary delivery points of the Enbridge CDA, Enbridge EDA, and Iroquois. This service provides the same flexible attributes as long haul FT service but along shorter paths.

[15] The Iroquois delivery point on the TCPL Mainline is near Waddington, New York, on the Canada – United States border.
[16] The Parkway delivery point is located near Milton, Ontario, at the south end of the TCPL Mainline and east end of the Union Gas Dawn-Parkway system.

In its 2017 gas supply plan, Enbridge has contracted for additional short haul capacity with primary delivery points of the Enbridge CDA and Enbridge EDA. Details can be referenced in Exhibit D1, Tab 2, Schedule 3 "Gas Costs, Transportation and Storage".

Storage Transportation Service (CDA and EDA)

TCPL's Storage Transportation Service ("STS"), in conjunction with long haul FT service, provides transportation to and from injection and withdrawal locations to help the Company manage both seasonal and daily fluctuations in market demand. The service allows for firm long haul injections to be delivered to the Company's injection locations all year, and for firm withdrawals from the withdrawal locations to the Company's market in the winter. For the Company, the injection locations are Parkway and Dawn and the withdrawal locations are Parkway and Kirkwall.

These contracts provide Enbridge flexibility through its four additional nomination windows (eight, in total, versus the typical four windows associated with most other transportation services) which allow intraday, or daily, load balancing. The additional nomination windows are particularly important in the winter, since weather fluctuations can cause significant demand swings throughout the day. In those cases, STS helps avoid LBA charges.

Short Term Firm Transportation

TCPL's Short Term Firm Transportation ("STFT") service has the same reliability as other FT services (long haul or short haul) but can be used to fill short term or seasonal transportation needs. The term of service ranges from a minimum of 7 days up to a maximum of one year less one day.

STFT is a discretionary service. Its toll is biddable and expressed as a percentage of the applicable FT toll in effect at time of service. In its Decision to RH-003-2011, the National Energy Board gave TCPL full discretion to determine the bid floors for STFT at 100 percent of the corresponding FT rate or higher.

In EB-2012-0459, Enbridge determined it was more cost effective to contract for full year FT service instead of five months of STFT service in the winter of 2014-2015.[17]

Firm Transportation Short Notice

TCPL's Firm Transportation Short Notice ("FT-SN") offers firm service with a primary receipt point and a primary delivery point designed to serve fluctuating demands with as little as 15 minutes notice (i.e., 96 nomination windows daily). Enbridge contracts for 85,000 GJ per day of FT-SN capacity from Parkway to the Victoria Square delivery point in the Enbridge CDA.

[17] EB-2012-0459, Exhibit N1, Tab 2, Schedule 1, Page 17-19.

3.2.2 Nova Transmission

The 23,500 km Nova Gas Transmission pipeline system gathers natural gas in Alberta and delivers to Empress where it meets the TCPL Mainline. Acquiring gas at AECO and transporting to Empress via the Nova Gas Transmission system adds diversity and reliability to the Enbridge gas supply portfolio, as it allows the Company to move upstream of the Empress delivery point. On the map in Appendix B, many of the interconnecting pipelines within Alberta, labeled in blue, are part of the Nova Gas Transmission system.

3.2.3 Alliance Transportation[18]

The 3,848 km Alliance Pipeline system originates near northeastern British Columbia and transports WCSB natural gas southeast to the Chicago Hub. The Company does not currently contract on Alliance but the service presents another option for Enbridge to bring WCSB gas to the franchise area.

3.2.4 Vector Pipeline

The Vector Pipeline is a 348 mile pipeline that links the Chicago Hub to the Dawn Hub, and interconnects with several pipelines, including the Alliance Pipeline in Illinois, Bluewater Storage in Michigan, and Enbridge Gas Storage in Ontario.

3.2.5 NEXUS Pipeline

Enbridge has signed a precedent agreement with NEXUS for 110,000 Dth per day of firm transportation service commencing as early as November 1, 2017. The NEXUS contract will diversify Enbridge's gas supply portfolio while improving the reliability of supplies being transported to Dawn at a competitive landed cost. In EB-2015-0175, the Board granted Enbridge pre-approval for the cost consequences of the NEXUS capacity.

The NEXUS pipeline will run from the Kensington Processing Plant in eastern Ohio, to interconnections with existing pipeline infrastructure in Michigan.

3.2.6 Link Pipeline

The Link Pipeline extends from a point on the United States – Canada border under the St. Clair River to Enbridge storage assets in Tecumseh, allowing the Company access to supply procured at MichCon Generic.

3.2.7 Union Gas Transportation

Union Gas M12 Transportation Service connects the Dawn Hub to delivery points at Parkway, Lisgar, and Kirkwall, including a direct connection to the Enbridge CDA. Gas flowing to these points also connects to

[18] Alliance is visible as a red line on the map in Appendix A.

the Enbridge CDA and Enbridge EDA through TCPL short haul FT service (including TCPL short haul service made possible through TBO on the Union system).

In addition to the M12 service, Union Gas offers two unique services on this path. C1 service transports gas from east to west, the opposite direction of the M12 service. This service is used to transport gas delivered to Kirkwall or Parkway (from Niagara or long haul FT, for example) for injection into storage in the summer. M12X is a bi-directional service which allows for transportation of gas between any two of the main points on the Union system, Dawn, Parkway, and Kirkwall.

3.3 Storage

Storage is a cost effective and reliable way to manage variances between supply and demand. During periods of low demand, gas deliveries via upstream pipelines to the Enbridge franchise area can exceed customer demand. This excess supply is typically injected into storage facilities that the Company owns or leases from storage providers. Conversely, when franchise demand exceeds incoming supply, this supply deficiency can be made up for through storage withdrawals. Storage helps lower gas supply costs by utilizing annual transportation contracts at a higher load factor[19] and enabling supply to be procured at more cost effective times of the year.

Enbridge has underground storage of its own at Tecumseh near Corunna in southwestern Ontario and at Crowland near Welland in the Niagara Region. Tecumseh is a large multiple-cycle facility, whereas Crowland is a small peak shaving facility. The Company also has contracted storage capacity with third-party providers that are valued at market based pricing. The size of the contracted capacity and the term of the contracts vary such that every year Enbridge will enter the market place via an RFP process seeking to replace the contracted capacity scheduled to expire March 31 of that year[20].

In EB-2014-0276, the Board approved a change in how Enbridge manages its storage targets. Historically the Company had established storage targets to maintain maximum deliverability from storage until late January to early February in order to meet design or near design demand requirements. As demand declined so too would storage deliverability throughout the winter. To offset the decline in deliverability, the Company would purchase additional delivered supplies if demand was greater than budgeted. This methodology was adequate in conditions close to or slightly below budget, but the exceptionally cold winter of 2013-2014 required significantly higher volumes of gas purchased at Dawn. In 2015, in order to avoid this situation from occurring again, the Company began forecasting storage targets such that maximum deliverability from storage could be maintained until the end of

[19] In terms of transportation contracts, Load Factor = Average Daily Demand / Contract Demand.
[20] The capacity replaced may be greater than, less than, or equal to the expiring contract depending on the needs of the Company in the upcoming year.

February and such that deliverability from storage would be sufficient to meet March peak day as late as March 31.

3.3.1 Physical vs. Synthetic Storage

The nature of the Tecumseh storage service described above is an example of "physical storage." Natural gas can be physically injected into storage during periods of low demand and physically withdrawn during periods of high demand; and there are physical assets such as wells and compressors involved in the injection and withdrawal process.

An alternative type of storage service is referred to as "synthetic storage." In this case, the Company agrees to deliver natural gas to a third-party over a defined period of time (typically in the summer period) and the party will deliver back the same volume of gas over a later period of time (typically in the winter).

Test year storage contracts, including both physical and synthetic contracts, are identified in Exhibit D1, Tab 2, Schedule 9, Page 2 "Status of Transportation & Storage Contracts".

4. Customer Types

4.1 Direct Purchase Customers

Enbridge customers have the option to choose between multiple service types with varying degrees of sophistication. Distribution services, including the receipt of gas at the Enbridge franchise area and delivery to a customer's terminal location, are provided to all customers. However, customers may elect to procure natural gas supply and/or transportation to the Enbridge franchise area using other means. The following is a list of the five types of services offered to Enbridge customers:

- Sales Service – customers rely on the Company to provide gas supply, transportation, and load balancing services;
- Western Transportation Service ("WTS") – customers deliver gas supply to the Empress Hub in Alberta and rely on the Company to provide transportation and load balancing services;
- Ontario Transportation Service ("OTS") – customers deliver gas supply to the Enbridge franchise area and rely on the Company to provide load balancing services;

- Dawn Transportation Service ("DTS") – customers deliver gas supply to the Dawn Hub in southwestern Ontario and rely on the Company to provide transportation and load balancing services;[21]
- Unbundled Service – customers do not require gas supply, transportation, or load balancing services from Enbridge, and are not considered in the gas supply plan.

Customers that elect to purchase their natural gas requirements directly from an entity other than the Company or who are brokers or agents for an end user are referred to as Direct Purchase customers, and subscribe to one of the WTS, OTS, or DTS services above. Direct purchase customers are obligated to deliver each day to the Company, at a specified delivery point[22], a Mean Daily Volume ("MDV")[23] of gas. Fluctuations in the demand for gas at the customer's terminal location are balanced by the Company and, therefore, it is important to consider what additional storage and transportation assets may be required. For example, a direct purchase customer with a low load factor, such as a residential customer, would be required to deliver the same MDV to Enbridge every day of the year, but their consumption profile could vary dramatically depending on weather. The Company may need to acquire additional assets to serve this customer in winter, when demand exceeds MDV.

4.2 Interruptible Customers

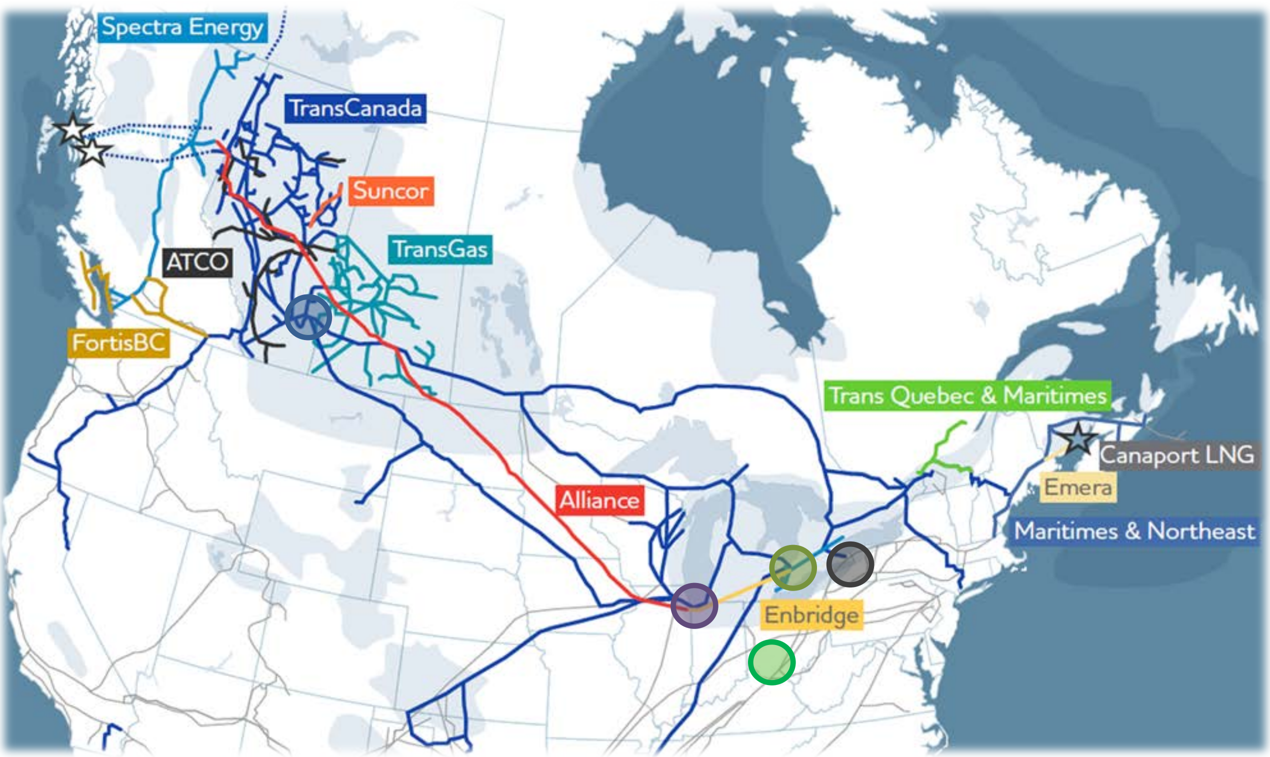
Certain Enbridge rate classes feature interruptible service, whereby customers may be required to curtail their natural gas consumption at the Company's request. These interruptible customers, and their "curtailment volumes", are a critical component of managing the distribution system. Once curtailment has been called, interruptible customers continue to deliver MDV but must cease consumption of gas, providing Enbridge with the flexibility of additional supply and reduced demand on the distribution system.

[21] This description is specific to Phase 2 of DTS. Details on all phases and conditions of DTS are outlined in the Dawn Access Application & Settlement Agreement, filed under EB-2014-0323.[22] Delivery points include: Empress, for Western Transportation Service customers; Dawn, for Dawn Transportation Service customers; or the Enbridge CDA/EDA for Ontario Transportation Service customers.[23] An entity's MDV is established at the start of a contract year as the average daily consumption over a period (typically 12 months).

[22] Delivery points include: Empress, for Western Transportation Service customers; Dawn, for Dawn Transportation Service customers; or the Enbridge CDA/EDA for Ontario Transportation Service customers.[23] An entity's MDV is established at the start of a contract year as the average daily consumption over a period (typically 12 months).

[23] An entity's MDV is established at the start of a contract year as the average daily consumption over a period (typically 12 months).

Appendix A



Source: CEPA & Enbridge

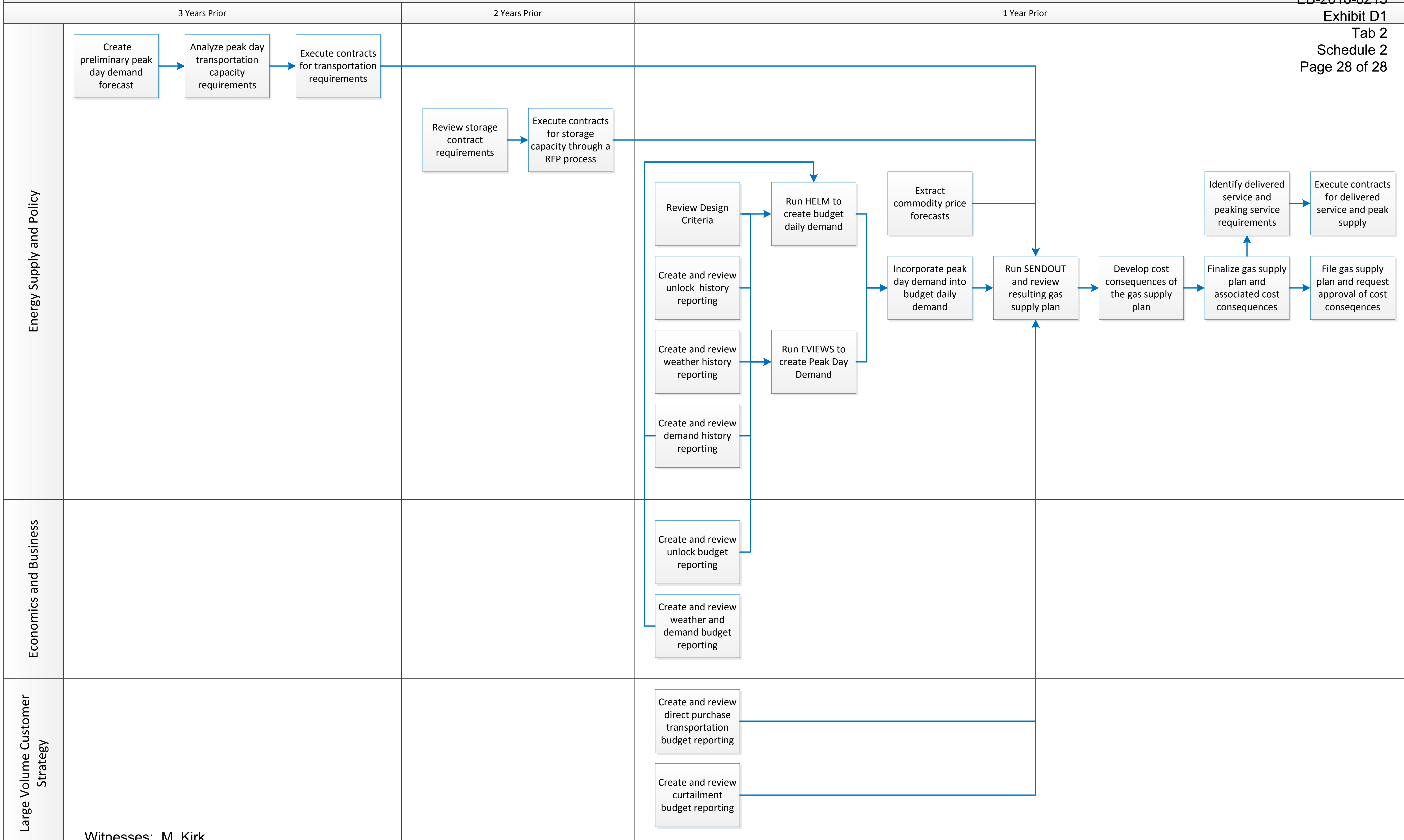
Appendix B

Source: U.S. Energy Information Administration based on data from various published studies. Canada and Mexico plays from ARI.
Updated: May 9, 2011

Witnesses: M. Kirk
D. Small

Gas Supply Planning Process
2016-08-31

Appendix C



Witnesses: M. Kirk
D. Small

2017 GAS, TRANSPORTATION, AND STORAGE COSTS

1. The purpose of this evidence is to provide an overview of the gas cost consequences of the gas supply activities of Enbridge Gas Distribution Inc. ("Enbridge" or "the Company") during the 2017 fiscal year. The process for developing the Company's 2017 gas supply plan and calculating budgeted gas costs is consistent with the approach and the gas supply principles described in the Gas Supply Memorandum at Exhibit D1, Tab 2, Schedule 2.

Review of Current Market Conditions and Gas Supply Planning Principles

2. The gas supply planning cycle begins with a review of North American natural gas market conditions. In recent years, changes to the TransCanada PipeLines Limited ("TCPL") Mainline toll structure and increasing supply opportunities in the United States northeast have influenced a shift from Alberta purchases (paired with long haul transportation) to Ontario purchases at the Dawn and Niagara receipt points (paired with short haul transportation). This influence is evident in the decisions made by Enbridge in TCPL's 2017 New Capacity Open Season ("2017 NCOS") discussed in Paragraph 13 and changes in M12 contracting described in Paragraph 18.

3. As Enbridge and other shippers shift supply obligations east, the Company also needs to ensure its gas supply plan is not overly reliant on one source of supply. To this end, Paragraphs 12 and 14 discuss efforts made by the Company to procure additional capacity upstream of Dawn, through Vector, NEXUS, and Link. These changes will increase the diversity of the gas supply portfolio and help maintain security of supply.

4. Throughout the gas supply planning process, the gas supply planning principles of reliability, diversity, flexibility, and landed cost, are revisited to ensure a well-designed and robust plan.

Peak Day Coverage

5. The Company's gas supply portfolio is structured first and foremost to meet peak demand. Enbridge has prepared its 2017 gas cost budget assuming peak day HDD values of 41.4 degree days in the Central Weather Zone, 48.2 degree days in the Eastern Weather Zone, and 38.8 degree days in the Niagara Weather Zone, as produced by current Design Criteria[1].

6. Based upon this design day forecast and the information available at the time, Enbridge is forecasting a design peak day volume of 106,363 10^3m^3 (4.0 PJs) during the winter season of the 2017 fiscal year.

7. A comparison of the 2017 Forecast Peak Day Supply Mix and the 2016 Forecast Peak Day Supply Mix can be found at Exhibit D1, Tab 2, Schedule 7. This schedule is structured in two parts: The first part, Budget Net Peak Day Demand (on Line 3), is the result of total system peak day demand less curtailment volumes[2]; the second part, displayed between Lines 4 and 11, is all of the services Enbridge has procured to meet peak day demand (the total of which is contained in Line 12). These include transportation services, deliveries from Ontario T-Service customers, third-party supplies delivered to the franchise area, and peaking service.

[1] Current Design Criteria is discussed in Section 2.3 of Exhibit D1, Tab 2, Schedule 2.
[2] Curtailment volumes are defined and discussed in Section 4.2 of D1, Tab 2, Schedule 2.

8. Note that the 2017 requirement for Peaking Supplies in the CDA and EDA, as indicated in Line 11, has not been contracted for at the time of this filing. However, for purposes of forecasting gas costs for 2017, a historical average of pricing has been used. Any variation between the actual and forecasted cost will be captured in the Purchased Gas Variance Account ("PGVA").

Transportation Planning and Costs

9. A summary of the Company's 2017 transportation contracts can be found at Exhibit D1, Tab 2, Schedule 9, page 1 (the Status of Transportation Contracts). Note that the total contracted daily volume on this schedule is greater than listed on the Forecast Peak Day Supply Mix schedule. This is due to the fact that the Peak Day Supply Mix schedule displays volumes delivered to the Enbridge franchise area, while the Status of Transportation Contracts schedule lists all Transportation contracts, including those that deliver volume to other receipt points such as Dawn, for transportation onwards to the CDA and EDA.

10. Enbridge has a number of Firm Transportation ("FT") and other service entitlements in place for system gas sourced in Western Canada and the United States during the 2017 fiscal year. These include service entitlements on traditional paths such as TCPL and the Vector Pipeline ("Vector"). TCPL long haul FT can be referenced at Line 4 of Schedule 7 and Lines 1 to 6 of Schedule 9. Vector capacity can be referenced in Lines 22 to 25 of Schedule 9, but is not identifiable in the Peak Day Supply Mix schedule since the capacity is delivered to Dawn rather than the Enbridge franchise area. Gas delivered to Dawn can be transported to the franchise area via TCPL short haul and STS (Schedule 7, Lines 6 and 7) as well as Union Deliveries (Schedule 7, Line 9). In the Status of Transportation Contracts schedule, TCPL short haul and STS transportation

contracts are identified in Lines 7 to 19, while Union transportation contracts are in Lines 28 to 39.

11. Effective November 1, 2017 the Company is forecasting the NEXUS Pipeline to be in-service, providing Enbridge the ability to acquire gas at the Dominion South point[3].

12. This supply will be transported via Kensington and interconnect with the Vector Pipeline. NEXUS capacity is identified in Line 26 of Schedule 4, and further discussed in Section 3.2.5 of Exhibit D1, Tab 2, Schedule 2 and in Schedule 3.

13. As a result of elections made in TCPL's 2017 New Capacity Open Season which closed January 30, 2015 ("2017 NCOS"), the Company will be converting currently contracted long haul capacity on TCPL to short haul capacity on TCPL, and contracting for incremental short haul capacity on TCPL, with all changes effective November 1, 2017. Specifically:

- 63,468 GJ per day of Empress to CDA capacity will be converted to an equivalent amount of Union Parkway to CDA capacity;
- An incremental 24,484 GJ per day of Union Parkway to CDA capacity will be added, for a total of 87,952 GJ (Line 9 of Schedule 9);
- 34,377 GJ per day of Empress to EDA capacity will be converted to an equivalent amount of Union Parkway to EDA capacity; and
- An incremental 48,737 GJ per day of Union Parkway to EDA capacity will be added, for a total of 83,114 (Line 11 of Schedule 9).

[3] Gas purchased for delivery on the NEXUS pipeline may not be procured at Dominion South, but Enbridge will refer to these supplies as Dominion South for the purposes of this evidence since it is the largest hub in the area.

14. To address additional seasonal requirements, the Company has contracted for 50,000 Dth per day of Vector capacity between December 1, 2016 and February 28, 2017 (Lines 22 to 25). This capacity will help reduce the Company's reliance on Dawn purchases in the winter, enhancing the gas supply plan's reliability and mitigating landed cost risk. In another effort to reduce the overall requirement of Delivered Supplies at Dawn, Enbridge has entered into an agreement effective November 1, 2016 for 40,000 GJ's per day of Link Pipeline capacity to be able to access US supplies via the MichCon system.

15. With the reduction in contracted long haul TCPL capacity, the Company is not forecasting any TCPL Unabsorbed Demand Charges ("UDC") and is not proposing a UDC Deferral Account for 2017. UDC has been forecast in prior years when the Company does not expect it will be able to fully utilize its contracted long haul TCPL capacity.

16. For the purposes of the 2017 forecast, the Company has also assumed that the Dawn T-Service option will become available to customers effective November 1, 2017 and that, as Direct Purchase agreements renew, customers will switch from the Ontario T-Service or Western T-Service options to Dawn T-Service, as per the election process. Prior to November 1, 2017, the Company plans to continue with Phase 1 of the Dawn Access Consultative by assigning a portion of its TCPL Dawn to CDA capacity to Direct Purchase customers[4]. The Company is also forecasting that customers who currently have an assignment of short haul capacity in accordance with Phase 1 will have their assignment renewed month-to-month beyond November 1, 2017 until their Direct Purchase agreement renewal date.

[4] Details on all phases and conditions of DTS are outlined in the Dawn Access Application & Settlement Agreement, filed under EB-2014-0323.

17. The impact of Direct Purchase customers shifting from Western or Ontario T-Service to Dawn T-Service is twofold: firstly, peak day deliveries to the franchise area via Ontario T-Service customers decline (Line 8 of the Peak Day Supply Mix schedule); secondly, the Company needs to increase volumes delivered to the franchise area to replace the decline in volume delivered by Ontario T-Service customers (currently that deficiency is mostly visible as an increase in Peaking Service in Line 11 of Schedule 7).

18. M12 and M12X service entitlements on the Union system currently total 2,795,102 GJ per day (3,718 MMcf per day), and are scheduled to increase by 190,000 GJ per day effective November 1, 2017 (Line 39 of Schedule 9). Enbridge also holds 236,586 GJ per day of westerly C1 capacity on the Union system (Line 36 of Schedule 9). M12 is a versatile service, providing delivery of gas by Union at Dawn for storage injection or onward transportation, as well as for gas withdrawn from storage at Tecumseh or Union, or both. As a transportation service, M12 provides onward transportation of gas sourced in Western Canada or the United States, or both, and delivered at Dawn. Of the 2,795,102 GJ per day of capacity listed above, 200,000 GJ per day is M12X capacity. M12X service differs from M12 service in that it is bi-directional, allowing for transportation of gas between any two of the main points on the Union system, Dawn, Parkway, or Kirkwall.

19. The Company also has M16 transportation capacity with Union to facilitate the use of the Chatham "D" Storage pool.

20. The gas cost forecast assumed January 1, 2016 Union tolls. Any variation between actual Union tolls and the forecasted tolls will be captured in the 2017 Storage and Transportation Deferral Account ("2017 S&TDA").

Witnesses: M. Kirk
D. Small

Supply Planning and Commodity Costs

21. Two supply sources have been added to Exhibit D1, Tab 2, Schedule 5, page 1 (the Summary of Gas Cost to Operations): Link Supplies, on Line 7; and Dominion Supplies, on Line 8. Link Supplies refer to gas procured at “MichCon Generic”, part of the DTE Energy system in Michigan, and transported to Tecumseh on the Link Pipeline. Dominion Supplies refer to gas acquired in the vicinity of the Dominion South point near the Marcellus and Utica shale basins, and transported to the Dawn Hub on the NEXUS and Vector Pipelines. The decision to acquire supplies from Link and Dominion supports diversity and reliability.

22. The Company’s forecast of gas supply acquisition during the 2017 Fiscal Year can be referenced in Exhibit D1, Tab 2, Schedule 6, the “Summary of Gas Costs to Operations”, and is reproduced in Table 1, below.[5]

Table 1: 2017 Volumes and Costs, by Source

Contract Type / Supply Source[6]	Volume (10^3m^3)
Western Canadian Supply	1,820,554.9
Ontario Production	365
Peaking	4,192.1
Chicago Supplies	1,682,897.7
Dominion Supplies	187,833.0
Link Supplies	322,632.0
Delivered Supplies	2,229,769.2
Niagara Supplies	1,936,853.3
Total	8,185,097.1

[5] The difference between the Total Volume in the table vs. Line 9 of Schedule 5 is equal to the TCPL Fuel Requirement, Line 1.6 of Schedule 5.
[6] Details on the supply sources can be found in Exhibit D1, Tab 2, Schedule 1, Section 3.1.

23. The prices assumed for the supplies listed in Table 1 reflect the market's assessment for the different expected delivery points in the Company's forecast of gas supply at the time of preparation of this evidence. In an effort to isolate the cost impact resulting from the change in supply mix, the Company removed the impact of the updated price forecast as compared to the July 1, 2016 QRAM.

24. This ensures that the changes in gas supply costs in Schedule 1 are driven by the change in volumes from various supply sources and not the change in prices of those supplies. This method of rebasing commodity prices under an updated supply mix is consistent with that used in previous years, including the determination of the 2016 gas cost budget filed in EB-2015-0114.

25. Any variance between the actual commodity cost and the forecasted prices will be captured in the 2017 PGVA. Also, any variation between the forecasted transportation tolls and the actual tolls will be captured in the 2017 PGVA.

26. Enbridge proposes that the 2017 volumetric forecast as set out at Exhibit D1, Tab 2, Schedule 6 be used, on an interim basis, for the purpose of deriving reference prices in 2017 QRAM applications by Enbridge, until a final decision in this proceeding is implemented. Following Board approval of 2017 volumes and the cost consequences of the 2017 gas supply plan, any adjustments, if necessary, will be made within the next QRAM application.

Storage[7]

27. Management of storage balances assumed in the 2017 gas supply plan is consistent with the methodology described in Section 3.3 of Exhibit D1, Tab 2,

[7] The Company has underground storage of its own at Tecumseh near Corunna in southwestern Ontario and at Crowland near Welland in the Niagara Region, but this section is concerned with storage provided by third-parties.

Schedule 2, whereby the Company is able to maintain maximum deliverability from storage until the end of February, and able to maintain deliverability sufficient to meet March peak day as late as March 31.

28. Storage contracts for capacity with third party providers are valued at market based pricing. The magnitude of the contracted capacity and the term of the contracts vary such that every year Enbridge will enter the marketplace via an RFP process seeking to replace the contracted capacity scheduled to expire March 31 of that year. For purposes of the 2017 gas cost forecast, the Company has assumed the amount and value of storage set to expire be extended. Any variation between this assumed cost and the actual cost of storage acquired through an RFP process will be captured in the 2017 S&TDA.

29. Storage contracts are identified in Exhibit D1, Tab 2, Schedule 9, page 2.

<u>Evaluation</u>

30. Enbridge evaluates its gas supply plan using four gas supply planning principles: Reliability, Diversity, Flexibility, and Landed Cost. Comments on the 2017 gas supply plan, as they relate to each planning principle are expanded below.

<u>Reliability</u>

31. In its 2017 gas supply plan, Enbridge has continued to focus on sourcing gas from established liquid hubs such as Empress and Dawn. Contracted capacity out of Dawn is at an all-time high for the Company. To avoid an over-reliance on daily purchases at Dawn, Enbridge will procure at sources upstream of Dawn by utilizing Vector capacity from Chicago and from Dominion South (via NEXUS). Since Niagara is a less liquid hub, the Company contracts for seasonal and annual supply rather than making daily purchases there.

Witnesses: M. Kirk
D. Small

Diversity

32. As discussed in paragraph 13, the Company is converting a significant portion of TCPL long haul capacity to TCPL short haul capacity. However, Enbridge has chosen to retain some TCPL long haul capacity to maintain diversity of path and source. The Company has also increased its diversity through the addition of Dominion South supply via NEXUS capacity, and through contracting for Link capacity. Appendix 1 charts the sources included in the 2017 gas supply portfolio as compared to the 2016 and 2015 gas supply portfolios to provide a visual representation of gas supply diversity.

Flexibility

33. Appendix 2 provides a visual representation of the gas supply portfolio's flexibility, in terms of contract renewal terms, broken down by delivery area. With 78% and 64% of contracted capacity delivered to the CDA and EDA, respectively, up for renewal in the next five years, Enbridge has ensured it will have options in its gas supply portfolio. In some cases, it is necessary to make longer-term commitments to satisfy other planning criteria. For example, the 15-year agreement with NEXUS is a significant benefit to diversity, reliability, and landed cost. In other cases, the Company is able to make shorter term supply and capacity arrangements, and does so when appropriate.

Landed Cost

34. The shift from long haul capacity to short haul capacity is contributing to a lower cost gas supply portfolio, on a per unit basis. Landed cost was considered in all contracting decisions made for 2017, weighed against the other three gas supply principles.

Witnesses: M. Kirk
D. Small

<u>Energy Content</u>

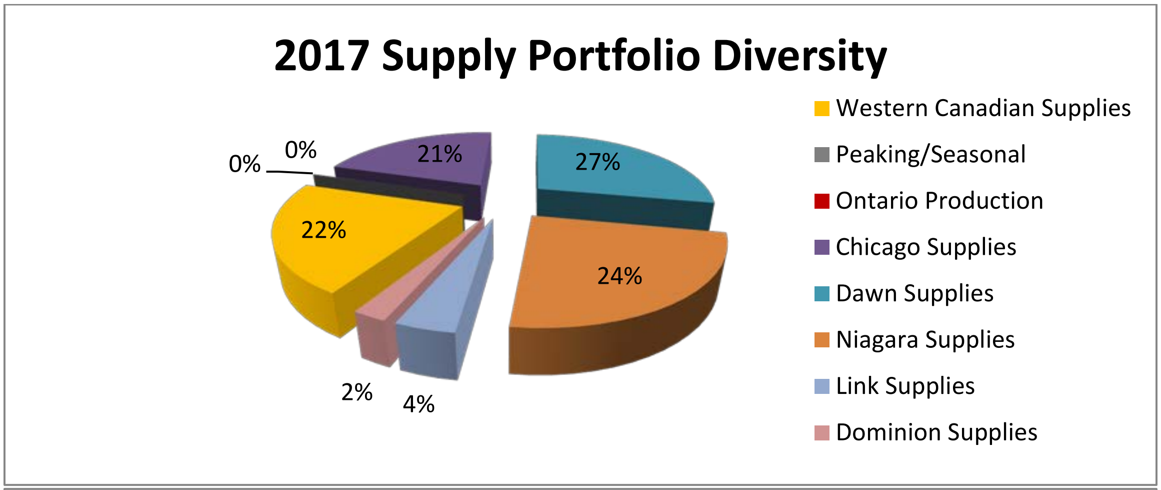
35. Enbridge has used a gross heating value of 37.69 MJ/m^3 to convert quantities (i.e., GJ, Dth) into volumes (i.e., 10^3m^3, MMcf). Quantities are the units specified in many of Enbridge's gas purchase and transportation service agreements, whereas Enbridge rates are volumetric.[8]

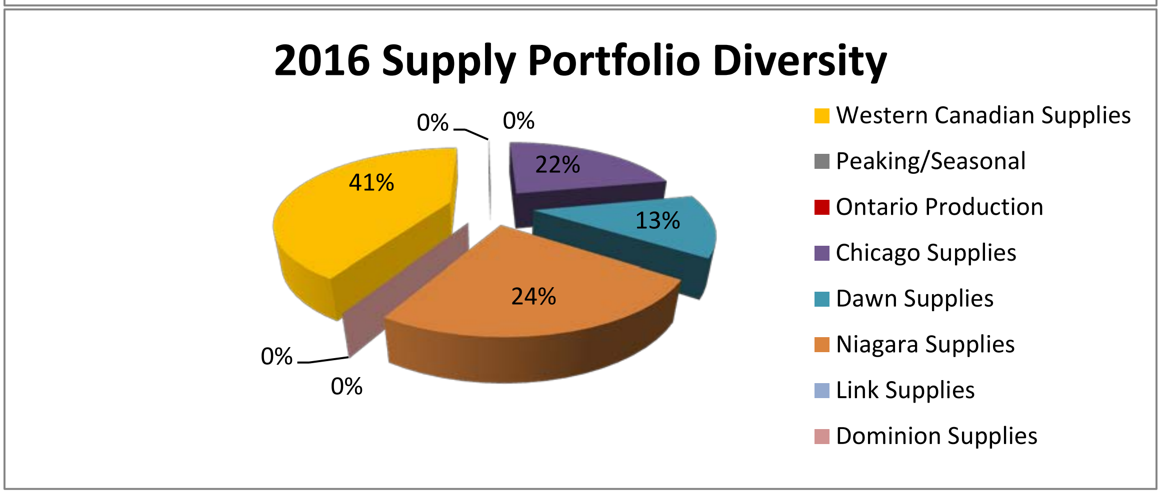
<u>Relief Requested</u>

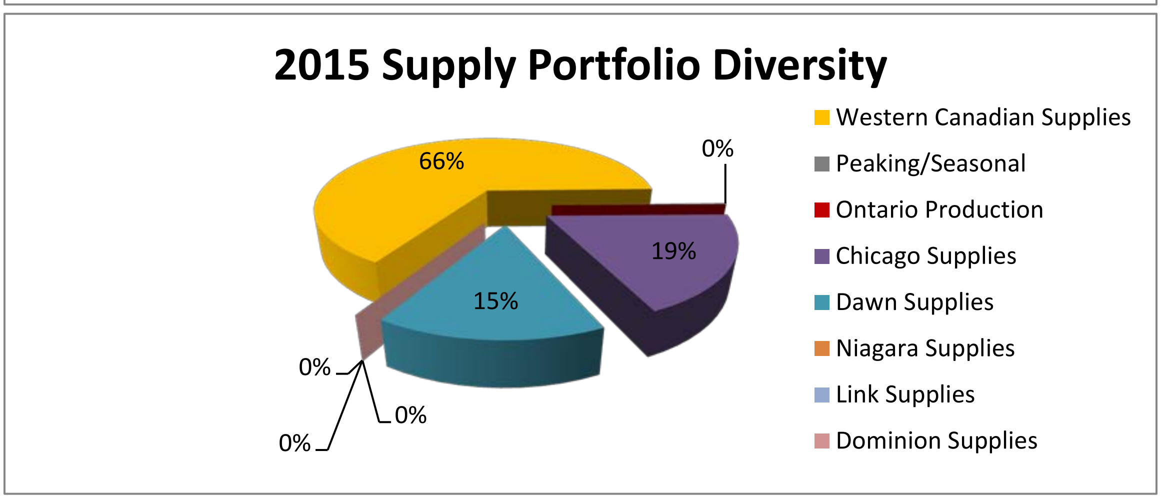
36. Based on the evidence above the Company requests recovery of the cost outcomes of its 2017 Gas Supply Plan and the associated Gas Cost forecast for 2017.

[8] Paragraph 36 of Exhibit D1, Tab 2, Schedule 11 discusses the Company's intention to investigate whether or not the heat value conversion factor needs to be changed in future years.

Appendix 1

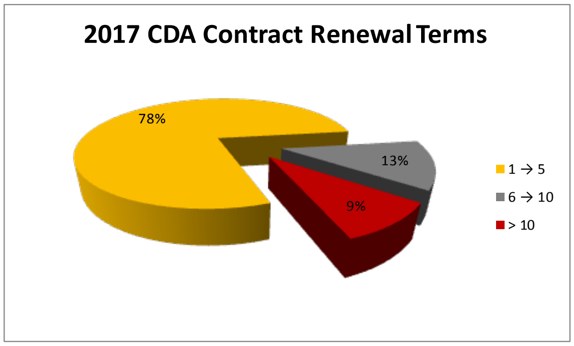


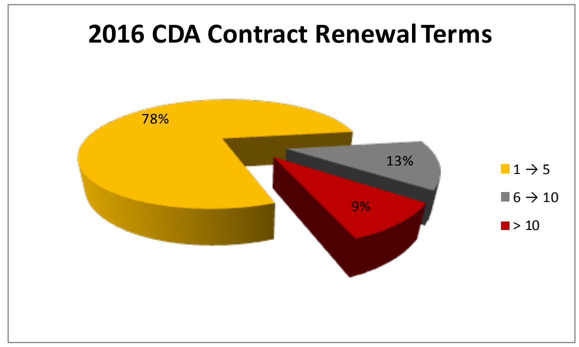


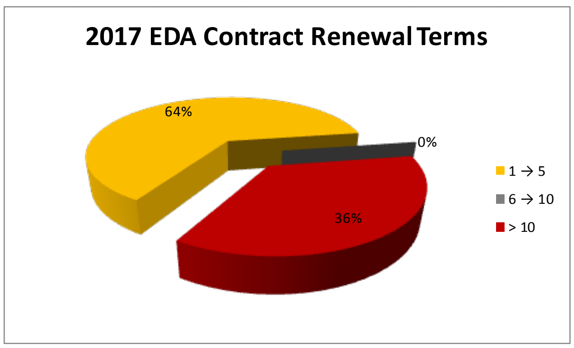


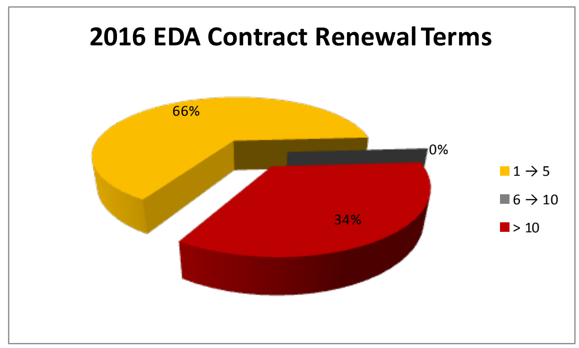
Witnesses: M. Kirk
D. Small

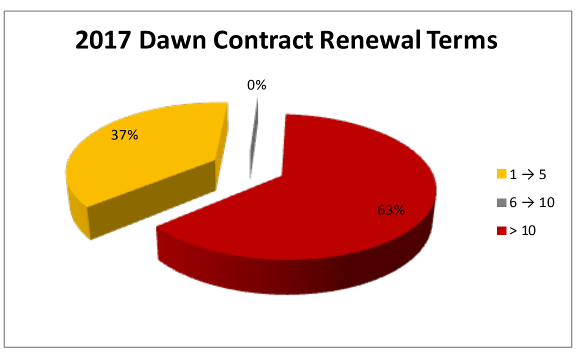
Appendix 2

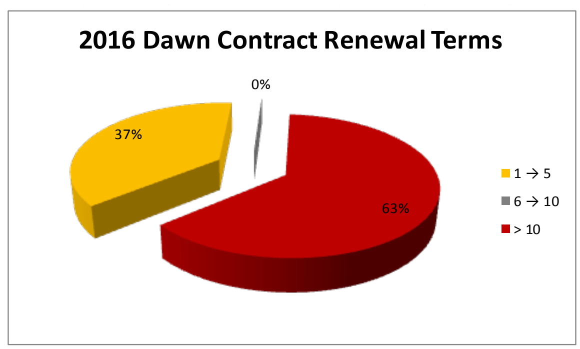


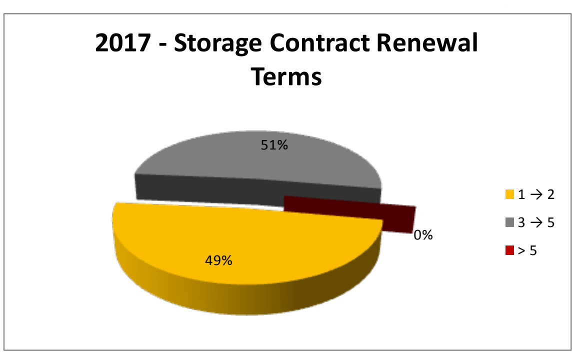


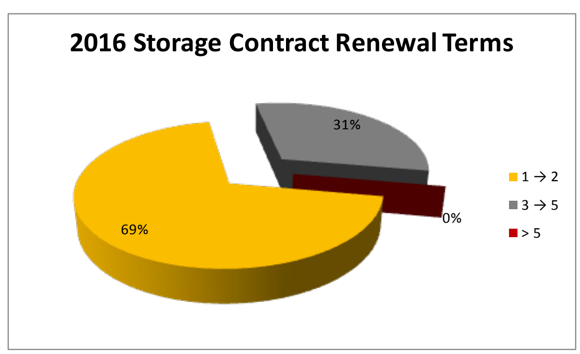












Witnesses: M. Kirk
D. Small

UNBILLED AND UNACCOUNTED-FOR GAS VOLUMES

Producing the UUF Forecast – 2017 Test Year

1. This evidence describes the forecast methodology and updates the forecast of Unbilled and Unaccounted-For Gas ("UUF") for the 2017 test year. The 2017 UUF forecast of 106,257 10^3m^3 is a component of the 2017 volumes budget which is part of the annual volumetric adjustment approved by the Board's EB-2012-0459 Decision with Reasons dated July 17, 2014.

2. The UUF forecast is produced using a two-step process involving the forecast of both Unaccounted-For Gas ("UAF") and unbilled volumes. The 2017 UUF forecast is equal to the 2017 UAF forecast plus the difference between the forecast December 2017 and forecast December 2016 unbilled volumes (i.e., change in unbilled volumes). Both the UAF and unbilled volumes forecasts are generated using the same regression models as have been employed throughout the current Custom IR term, consistent with the agreement in the Settlement Proposal in the EB-2015-0114 proceeding (Exhibit N1, Tab 1, Schedule 1, page 8).

3. UAF data for years prior to 2005 have been transformed to calendar year format in order to produce a calendar year UAF forecast. For an explanation of the transformation of volumes from fiscal to calendar year format, please see EB-2006-0034, Exhibit C1, Tab 3, Schedule 1.

Unbilled Volumes

4. The Company uses a regression model to forecast the level of monthly unbilled volumes. The model relies on the high degree of correlation between volumes and degree days.

Witnesses: M. Kirk
D. Small

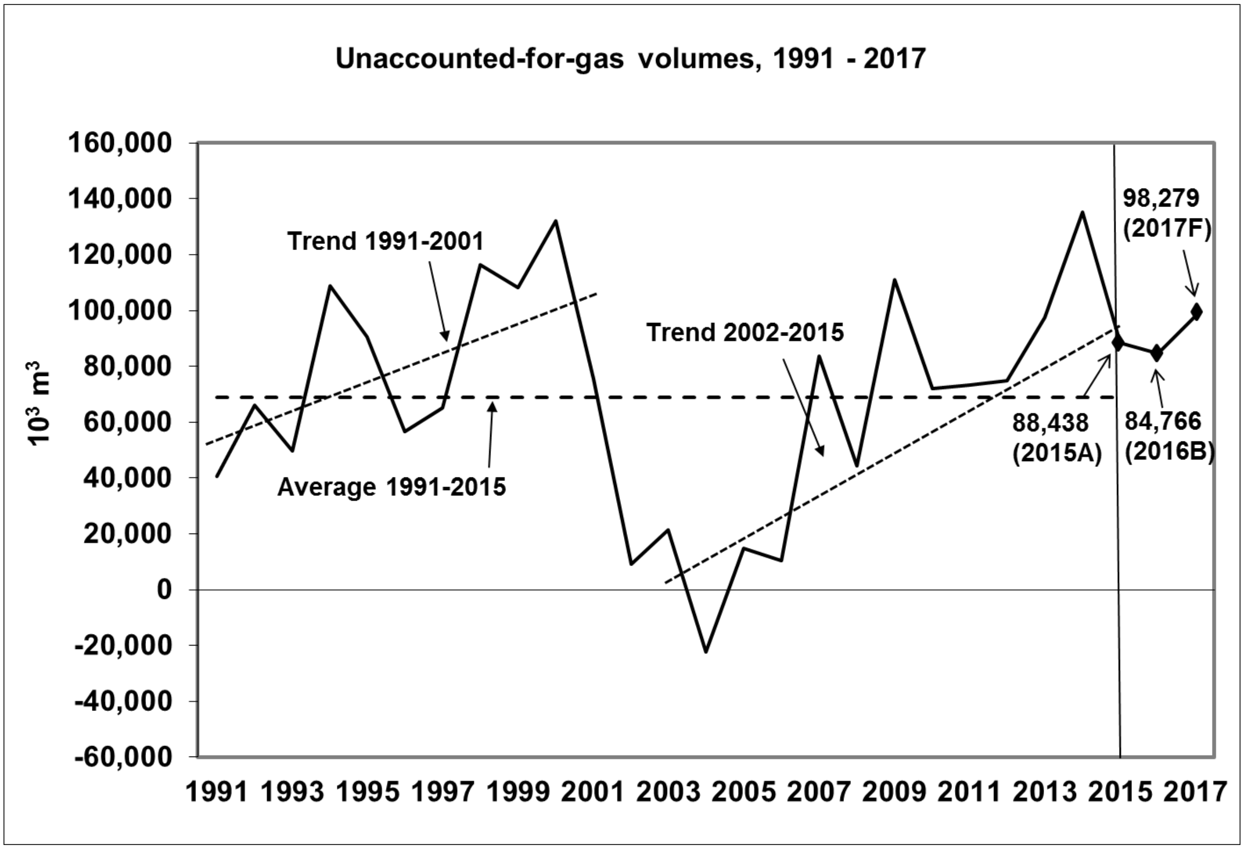
5. The change in unbilled volumes from December 2016 and December 2017 recognizes that at the end of any given year, a portion of volumes are captured in the current year that should reside in the previous year because billing does not reflect calendar months, and similarly, a portion of volumes are estimated in the following year that should reside in the current year. To net out the effects of both with the least administrative burden, the change in unbilled volumes is recorded annually in the same fashion.

Unaccounted For Gas Forecast ("UAF")

6. For the 2016 test year, the Company tested a variety of forecasting models and proposed to use the model that produced the most accurate and reasonable results. In the Settlement Proposal for EB-2015-0114, parties agreed that it is not appropriate to update UAF forecasting methodology during the Custom IR term. The Board approved the Settlement Proposal in its Decision and Order dated December 10, 2015. As a result, the model applied and approved as a part of the 2015 Rate Application (EB-2014-0276) will continue to be used for the remaining Custom IR term.

7. Figure 1 shows historical UAF data to 2015 along with the 2016 approved budget and the 2017 forecast. The graph also shows the 1991 to 2001 trend, the 2002 to 2015 trend line, and the 1991 to 2015 average.

Figure 1



8. Table 1 presents UAF actuals along with most recently approved Budget values.

Table 1
UAF Actuals vs Board Approved

Col. 1	*Col. 2*	*Col. 3*
Calendar Year	**Actual**	**Board Approved**
2011	73,355	64,211
2012	74,762	68,925
2013	97,361	73,092
2014	135,380	77,660
2015	88,438	81,519
2016	-	84,766

Witnesses: M. Kirk
D. Small

<u>Calculation of 2017 UUF</u>

9. The total UUF forecast is generated by adding the difference between forecast December 2017 unbilled volumes and forecast December 2016 unbilled volumes to the 2017 UAF forecast. As such, the 2017 Test Year UUF forecast is as follows:

2017 UUF = (Forecast of UAF Gas) + (Change in Unbilled Gas)
= (Forecast of UAF Gas) + (Forecast of December 2017 Unbilled Gas - Forecast for December 2016 Unbilled Gas)
= 98,279 10^3m^3 + (744,548 10^3m^3 – 736,570 10^3m^3)
= 98,279 10^3m^3 + 7,978 10^3m^3
= 106,257 10^3m^3

Witnesses: M. Kirk
D. Small

Summary of Gas Cost to Operations
Year ended December 31, 2017

Item #		Col. 1 10^3m^3	Col. 2 $(000)	Col. 3 $/$10^3m^3$ (Col.2 / Col.1)	Col. 4 $/GJ (Col.3 / 37.69)
	Western Canadian Supplies				
1.1	Alberta Production	-	-	0.000	0.000
1.2	Western - @ Empress - TCPL	859,509.9	87,414.5	101.703	2.698
1.3	Western - @ Nova - TCPL	960,657.6	92,784.9	96.585	2.563
1.4	Western Buy/Sell - with Fuel	387.4	41.6	107.323	2.848
1.5	Western - @ Alliance	-	-	0.000	0.000
1.6	Less TCPL Fuel Requirement	(73,778.8)	-		
1.	Total Western Canadian Supplies	1,746,776.0	180,241.1	103.185	2.738
2.	Peaking Supplies	4,192.1	4,825.8	1,151.173	30.543
3.	Ontario Production	365.0	64.9	177.724	4.715
4.	Chicago Supplies	1,682,897.7	232,214.9	137.985	3.661
5.	Dawn Supplies	2,229,769.2	341,483.7	153.148	4.063
6.	Niagara Supplies	1,936,853.3	245,738.3	126.875	3.366
7.	Link Supplies	322,632.0	43,649.6	135.292	3.590
8.	Dominion Supplies	187,833.0	20,755.5	110.500	2.932
9.	Total Supply Costs	8,111,318.2	1,068,973.6	131.788	3.497
	Transportation Costs				
10.1	TCPL - FT - Demand		135,395.4		
10.2	- FT - Commodity		0.0		
10.3	- Parkway to CDA		6,403.8		
10.4	- STS - CDA		21,268.5		
10.5	- STS - EDA		15,433.4		
10.6	- Dawn to CDA		7,576.3		
10.7	- Dawn to EDA		78,343.5		
10.8	- Dawn to Iroquois		10,110.8		
10.9	Other Charges		0.0		
10.10	Nova Transmission		7,464.6		
10.11	Alliance Pipeline		0.0		
10.12	Vector Pipeline		20,369.9		
10.13	Nexus Pipeline		6,065.0		
10.14	Niagara Link Pipeline		2,150.7		
10.15	Niagara Falls to Enbridge Parkway CDA		18,100.7		
10.	Total Transportation Costs		328,682.5		
11.	Total Before PGVA Adjustment	8,111,318.2	1,397,656.1	172.309	4.572
12.	PGVA Adjustment		(43,869.0)		
13.	Total Purchases & Receipt	8,111,318.2	1,353,787.1	166.901	4.428

Witnesses: H. Sayyan
M. Suarez

Summary of Gas Cost to Operations
Year ended December 31, 2017

Item #		Col. 1 10^3m^3	Col. 2 $(000)	Col. 3 $/$10^3m^3$ (Col.2 / Col.1)	Col. 4 $/GJ (Col.3 / 37.69)
13.	Total Purchases & Receipt	8,111,318.2	1,353,787.1	166.901	4.428
14.	Storage Fluctuation	45,585.0	7,608.2	166.901	
15.	Commodity Cost to Operations	8,156,903.2	1,361,395.3	166.901	
16.	Storage and Transportation Costs		138,777.2		
17.	Gas Cost to Operations	8,156,903.2	1,500,172.5	183.914	4.880
18.	Western T-Service Transportation Costs		102,915.1		
19.	Forecasted Gas Costs	8,156,903.2	1,603,087.6	196.531	5.214

Reconciliation Of Natural Gas Sendout Volumes
To Sales Volumes
Year ended December 31, 2017

Item #		
1.	Sendout To Operations	8,156,903.2
2.	T-Service Volumes	3,692,264.6
3.	Total Sendout	11,849,167.9
4.1	Residential Sales	4,659,173.8
4.2	Commercial Sales	2,758,886.9
4.3	Industrial Sales	458,120.7
4.4	T-Service	3,670,085.4
4.5	Rate 200 T-Service (Gazifere)	42,090.8
4.6	Rate 200 Sales (Gazifere)	128,751.9
4.7	Company Use	5,436.5
4.8	Unaccounted For (UAF)	98,279.0
4.9	Unbilled Forecast - Sales	27,889.2
4.10	Unbilled Forecast - T-Service	(19,911.5)
4.11	Lost and Unaccounted For (LUF)	20,365.2
4.	Total System Requirements	11,849,167.9

Witnesses: H. Sayyan
M. Suarez

Summary of Storage & Transportation Costs
Fiscal 2017

Item #	Units - $(000)	Col. 1 Storage & Transportation Charges Incurred in Fiscal 2017	Col. 2 Fiscal 2017 Storage Charges Recovered in Fiscal 2017	Col. 3 Fiscal 2016 Storage Charges Recovered in Fiscal 2017	Col. 4 Total Storage & Transportation Charges Recovered in Fiscal 2017
	Storage				
1.1	Chatham D	151.2	85.5	65.7	151.2
1.2	Injection	102.3	30.7	58.2	88.9
1.3	Withdrawal	102.3	102.3	0.0	102.3
1.4	Market Based Storage	16,792.6	9,249.0	6,992.7	16,241.7
1.5	Unutilized Transportation Costs	0.0	0.0	0.0	0.0
1.6	Other	3,241.4	2,393.1	750.1	3,143.2
1.	Total Storage	20,389.7	11,860.6	7,866.7	19,727.3
2.	Total Transportation	100,471.5	55,191.8	38,625.2	93,817.0
	Dehydration				
3.1	Demand	1,038.4	570.9	461.2	1,032.1
3.2	Commodity	214.3	214.3	0.0	214.3
3.	Total Dehydration	1,252.7	785.2	461.2	1,246.4
4.	Total Storage & Other Costs	122,113.9	67,837.6	46,953.1	114,790.7
	Fuel Costs				
5.1	Tecumseh	2,862.9	1,805.6	1,056.9	2,862.5
5.2	Union Storage	1,331.3	670.5	718.1	1,388.6
5.3	Union Transportation	20,304.9	19,153.8	581.6	19,735.4
5.	Total Fuel Costs	24,499.1	21,630.0	2,356.6	23,986.5
6.	Unutilized Transportation Costs	0.0	0.0	0.0	0.0
7	Total Storage & Transportation	146,613.0	89,467.6	49,309.6	138,777.2
8.	Storage and Transportation Costs Charged to Gas Cost to Operations				138,777.2

	2016 Budget Peak Day Demand - as filed in EB-2015-0114				2017 Budget Peak Day Demand			
		Column 1	Column 2	Column 3		Column 4	Column 5	Column 6
Item #	GJ's	CDA	EDA	Total	GJ's	CDA	EDA	Total
1.	Demand	3,321,901	686,930	4,008,832	Demand	3,360,682	697,973	4,058,655
2.	Less Curtailment	(87,208)	(36,056)	(123,263)	Less Curtailment	(78,012)	(34,897)	(112,909)
3.	Net Peak Day Demand	3,234,694	650,875	3,885,568	Net Peak Day Demand	3,282,669	663,076	3,945,746
4.	TCPL FT Capacity	138,468	390,377	528,845	TCPL FT Capacity	138,468	224,377	362,845
5.	TCPL STFT	-	-	-	TCPL STFT	-	-	-
6.	TCPL Short Haul	226,840	154,000	380,841	TCPL Short Haul	228,046	154,000	382,046
7.	TCPL STS	369,465	80,611	450,076	TCPL STS	369,465	250,611	620,076
8.	Ontario T-Service	231,114	5,417	236,531	Ontario T-Service	209,846	4,602	214,448
9.	Union Deliveries	2,175,027	-	2,175,027	Union Deliveries	2,175,027	-	2,175,027
10.	Delivered Service	132,738	-	132,738	Delivered Service	132,738	-	132,738
11.	Peaking Service	-	20,469	20,469	Peaking Service	29,080	29,486	58,565 (1)
12.	Total Supply	3,273,653	650,875	3,924,527	Total Supply	3,282,669	663,076	3,945,746
13.	Sufficency/(Deficiency)	38,959	-	38,959	Sufficency/(Deficiency)	-	-	-

note (1) - At the time of the filing of the 2017 gas cost budget the Peaking Services requirement had not been contracted for

		Gas Supply/Demand Balance		
		Col. 1	Col. 2	Col. 3
		2017 Budget	2016 Budget	2015 Actual
Item #		10^3m^3	10^3m^3	10^3m^3
1.	Total Demand	11,849,167.9	11,672,327.1	12,248,490.4
	Deliveries			
2.1	Western Canadian Supplies	1,746,776.0	3,393,331.8	5,093,126.6
2.2	Peaking/Seasonal	4,192.1	2,154.4	10,989.6
2.3	Ontario Production	365.0	366.0	87.5
2.4	Chicago Supplies	1,682,897.7	1,793,050.4	1,445,256.3
2.5	Delivered Supplies	2,229,769.2	1,052,334.6	1,138,149.8
2.6	Niagara Supplies	1,936,853.3	1,942,159.7	-
2.7	Link Supplies	322,632.0	-	-
2.8	Dominion Supplies	187,833.0	-	-
2.9	Direct Purchase Delivery	3,721,751.4	3,631,350.4	4,659,436.0
2.10	Storage (Injection)/Withdrawal	16,098.1	(142,420.0)	(98,555.3)
2.	Total Delivery	11,849,167.8	11,672,327.2	12,248,490.4

Total Demand includes both System Sales and T-Service Consumption

2017 Budget

Gas Supply/Demand Balance

Item #		Col. 1 January 10^3m^3	Col. 2 February 10^3m^3	Col. 3 March 10^3m^3	Col. 4 April 10^3m^3	Col. 5 May 10^3m^3	Col. 6 June 10^3m^3	Col. 7 July 10^3m^3	Col. 8 August 10^3m^3	Col. 9 September 10^3m^3	Col. 10 October 10^3m^3	Col. 11 November 10^3m^3	Col. 12 December 10^3m^3	Col. 13 Total 10^3m^3
1.	Total Demand	1,997,611.4	1,708,006.0	1,527,987.6	975,454.5	565,482.6	369,550.5	350,018.7	349,985.2	376,289.2	735,749.4	1,210,947.2	1,682,085.4	11,849,167.7
	Deliveries													
2.1	Western Canadian Supplies	144,061.6	131,977.4	148,174.1	145,384.2	152,286.6	149,364.0	156,399.1	158,455.3	155,333.8	162,567.8	111,827.0	130,945.2	1,746,776.0
2.2	Peaking/Seasonal	4,192.1	-	-	-	-	-	-	-	-	-	-	-	4,192.1
2.3	Ontario Production	31.0	28.0	31.0	30.0	31.0	30.0	31.0	31.0	30.0	31.0	30.0	31.0	365.0
2.4	Chicago Supplies	195,259.5	176,363.4	151,870.4	146,971.3	151,870.4	146,971.3	151,870.4	151,870.4	146,971.3	151,870.4	54,594.5	56,414.3	1,682,897.7
2.5	Dawn Supplies	493,499.6	222,870.8	-	39,798.4	131,599.9	127,354.7	131,599.9	131,599.9	127,354.7	131,599.9	198,991.8	493,499.6	2,229,769.2
2.6	Niagara Supplies	164,499.9	148,580.5	164,499.9	159,193.4	164,499.9	159,193.4	164,499.9	164,499.9	159,193.4	164,499.9	159,193.4	164,499.9	1,936,853.3
2.7	Link Supplies	32,900.0	29,716.1	32,900.0	31,838.7	32,900.0	31,838.7	32,900.0	32,900.0	31,838.7	32,900.0	-	-	322,632.0
2.8	Dominion Supplies	-	-	-	-	-	-	-	-	-	-	92,376.9	95,456.1	187,833.0
2.9	Direct Purchase Delivery	326,938.6	293,442.1	322,826.1	310,422.4	318,713.6	306,442.6	314,601.1	312,544.8	300,472.8	308,432.3	298,482.9	308,432.3	3,721,751.4
2.10	Storage (Injection)/Withdrawal	636,229.2	705,027.7	707,686.2	141,816.1	(386,418.6)	(551,644.3)	(601,882.5)	(601,916.1)	(544,905.6)	(216,151.8)	295,450.8	432,807.1	16,098.1
2.	Total Delivery	1,997,611.4	1,708,006.0	1,527,987.6	975,454.5	565,482.6	369,550.5	350,018.7	349,985.2	376,289.2	735,749.4	1,210,947.2	1,682,085.4	11,849,167.7

Total Demand includes both System Sales and T-Service Consumption

Status of Transportation & Storage Contracts

Item #	Contract	Primary Receipt Point	Primary Delivery Point	Total Contracted Daily Volume	Contract Unit	Fuel Rate	Monthly Demand Charge	Demand Charge Unit	Renewal Date	Expiry Date	
	TransCanada Long haul										
1	TCPL FT - CDA	Empress	CDA	63,468	GJ	varies	60.77142	$/GJ		31-Oct-17	1
2	TCPL FT - CDA	Empress	CDA	75,000	GJ	varies	60.77142	$/GJ	31-Oct-16	31-Oct-18	
3	TCPL FT - EDA	Empress	EDA	34,377	GJ	varies	62.50257	$/GJ		31-Oct-17	1
4	TCPL FT - EDA	Empress	EDA	163,044	GJ	varies	62.50257	$/GJ	31-Oct-20	31-Oct-22	
5	TCPL FT - EDA	Empress	EDA	166,000	GJ	varies	62.50257	$/GJ		31-Oct-17	2
6	TCPL FT - Iroquois	Empress	Iroquois	26,956	GJ	varies	63.11183	$/GJ	31-Oct-20	31-Oct-22	
	TransCanada Short haul										
7	TCPL FT Dawn to CDA	Dawn	CDA	149,818	GJ	varies	11.40236	$/GJ	31-Oct-20	31-Oct-22	
8	TCPL FT Dawn to CDA	Dawn	CDA	(121,772)	GJ	varies	11.40236	$/GJ		31-Oct-17	3
9	TCPL FT Dawn to CDA	Dawn	CDA	87,952	GJ	varies	11.40236	$/GJ	31-Oct-30	31-Oct-32	1
10	TCPL FT Dawn to EDA	Dawn	EDA	114,000	GJ	varies	21.33019	$/GJ	31-Oct-20	31-Oct-22	
11	TCPL FT Dawn to EDA	Dawn	EDA	83,114	GJ	varies	21.33019	$/GJ	31-Oct-30	31-Oct-32	1
12	TCPL FT Parkway to EDA	Parkway	EDA	170,000	GJ	varies	15.60578	$/GJ	31-Oct-29	31-Oct-31	4
13	TCPL FT Dawn to Iroquois	Dawn	Iroquois	40,000	GJ	varies	20.49473	$/GJ	31-Oct-20	31-Oct-22	
14	TCPL FT Parkway to CDA	Parkway	CDA	572	GJ	varies	6.29836	$/GJ	31-Oct-20	31-Oct-22	
15	TCPL FT-SN Parkway to CDA	Parkway	CDA	85,000	GJ	varies	6.14977	$/GJ	31-Oct-20	31-Oct-22	
16	Niagara to CDA	Niagara	CDA	200,000	GJ	varies	8.35336	$/GJ	31-Oct-28	31-Oct-30	5
	TransCanada Storage Transportation Service										
17	TCPL STS Parkway to CDA	Parkway	CDA	283,892	GJ	varies	5.92119	$/GJ	31-Oct-20	31-Oct-22	
18	TCPL STS Parkway/Kirkwall to EDA		EDA	70,895	GJ	varies	15.60578	$/GJ	31-Oct-20	31-Oct-22	
19	TCPL STS Parkway to EDA	Parkway	EDA	9,716	GJ	varies	15.60578	$/GJ	31-Oct-20	31-Oct-22	
	Nova Transmission										
20	Nova Transmission	NIT	Empress	86,869	GJ	N/A	6.26000	$/GJ	31-Oct-16	31-Oct-17	
	Alliance Transportation										
21	Alliance Transportation			-	mcf	N/A	N/A				
	Vector Pipeline										
22	Vector Pipeline	Chicago	Canadian Border	110,000	dth	varies	7.0140	$US/dth	31-Oct-30	31-Oct-32	7
23	Vector Pipeline	Canadian Border	Dawn	116,056	GJ	varies	0.5705	$/GJ	31-Oct-30	31-Oct-32	
24	Vector Pipeline	Chicago	Canadian Border	65,000	dth	varies	7.0140	$US/dth	31-Oct-18	31-Oct-20	
25	Vector Pipeline	Canadian Border	Dawn	68,579	GJ	varies	0.5705	$/GJ	31-Oct-18	31-Oct-20	
	Nexus Pipeline										
26	Nexus Pipeline	Kensington	Milford Junction	110,000	dth	varies	21.2920	$US/dth	31-Oct-30	31-Oct-32	
	Link Pipeline										
27	Link Pipeline	MichCon Generic		42,202	GJ	varies	varies	$/GJ	1-Nov-16	31-Oct-17	
	Union Gas Transportation										
28	Union Gas Dawn to Parkway			1,764,678	GJ	varies	2.6040	$/GJ	31-Oct-20	31-Oct-22	
29	Union Gas Dawn to Parkway			106,000	GJ	varies	2.6040	$/GJ	31-Oct-16	31-Oct-18	
30	Union Gas Dawn to Parkway			57,100	GJ	varies	2.6040	$/GJ	31-Oct-17	31-Oct-19	
31	Union Gas Dawn to Parkway			18,703	GJ	varies	2.6040	$/GJ	31-Oct-16	31-Oct-18	
32	Union Gas Dawn to Parkway - M12X			200,000	GJ	varies	3.2440	$/GJ	31-Oct-20	31-Oct-22	
33	Union Gas Dawn to Lisgar			10,692	GJ	varies	2.6040	$/GJ	31-Oct-16	31-Oct-18	
34	Union Gas Dawn to Kirkwall			35,806	GJ	varies	2.1930	$/GJ	31-Oct-16	31-Oct-18	
35	Union Gas Dawn to Kirkwall			32,123	GJ	varies	2.1930	$/GJ	31-Oct-16	31-Oct-18	
36	Union Gas Parkway to Dawn - C1			236,586	GJ	varies	0.6400	$/GJ	31-Mar-17	31-Mar-19	
37	Union Gas Dawn to Parkway			400,000	GJ	varies	2.6040	$/GJ	31-Oct-23	31-Oct-25	
38	Union Gas Dawn to Parkway			170,000	GJ	varies	2.1930	$/GJ	31-Oct-29	31-Oct-31	4
39	Union Gas Dawn to Parkway			190,000	GJ	varies	2.1930	$/GJ	31-Oct-30	31-Oct-32	6

review notes

notes:
(1) - Effective November 1, 2017 GJs 63,468 of CDA capacity and 34,377 of EDA capacity will be converted from LH to SH and incremental new capacity of 24,484 to the CDA and 48,737 to the EDA- contin
(2) - Contract terminates the earlier of October 31, 2017 and the inservice date of contract described at Line 12 above
(3) - Assignment to Direct Purchase effective November 1, 2015 to October 31, 2017. Assignments will be extended month to month to coincide with renewal dates of Direct Purchase Agreements
(4) - Contract is effective November 1, 2016
(5) - Contract is split between deliveries at Niagara Falls (76,559) and Chippawa (123,441)
(6) - Contract is effective November 1, 2017
(7) - Tolls for Vector US capacity are reduced upon in-service date of Nexus

Witness: D. Small

Status of Transportation & Storage Contracts

Storage Contract Summary

Contract	Annual Volume GJ's	Effective Date	Expiry Date
A	5,055,056	April 1, 2012	March 31, 2017
B	3,165,168	April 1, 2013	March 31, 2018
C	2,110,112	April 1, 2013	March 31, 2018
D	4,000,000	April 1, 2014	March 31, 2019
E	3,000,000	April 1, 2015	March 31, 2020
F	3,000,000	April 1, 2015	March 31, 2020
G	1,055,056	April 1, 2016	March 31, 2017
H	1,582,584	April 1, 2016	March 31, 2019
I	1,500,000	April 1, 2016	March 31, 2021

	PJ's	Maximum Withdrawal PJ's	Deliverability	Maximum Injection PJ's	Deliverability
Total Contracted Capacity	24.5	0.4	1.67%	0.2	0.88%
EGD Regulated Storage	97.8	1.9	1.90%	0.7	0.72%

MONTHLY PRICING INFORMATION

	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5
	21 Day Average Empress CGPR	21 Day Average NYMEX	21 Day Average Chicago	21 Day Average US Exchange	$\$CAD/10^3m^3$ Equivalent (Note 1)
	$CAD/GJ	$US/MMBtu	$US/MMBtu	$CAD/$US	
Jan-17	2.8331	3.0653	3.2849	1.2968	
Feb-17	2.8349	3.0588	3.2870	1.2967	
Mar-17	2.7833	3.0149	3.1052	1.2966	
Apr-17	2.5770	2.8254	2.8426	1.2964	
May-17	2.5493	2.8165	2.7629	1.2962	
Jun-17	2.5541	2.8489	2.7519	1.2960	
Jul-17	2.5494	2.8869	2.7634	1.2959	
Aug-17	2.6251	2.8975	2.7465	1.2957	
Sep-17	2.6398	2.8931	2.7722	1.2954	
Oct-17	2.7948	2.9201	2.8095	1.2952	
Nov-17	2.9460	2.9941	3.0626	1.2949	
Dec-17	3.0886	3.1335	3.2616	1.2946	
	2.7313	2.9462	2.9542	1.2959	102.9423
TCPL Fuel Ratio		4.22%			107.2912

(note 1)
Can$/Gj = (NYMEX - Basis) / 1.055056 * US Exchange Rate

(Note 1) $\$CAD/10^3m^3$ = $CAD/GJ * 37.69 Mj/m3

21 Day Period **3-May-16** **to** **31-May-16**

Natural Gas Conversions

mcf times 0.028328 = 10^3m^3

1 Dth = 1 mcf

MMBtu times 1.055056 = GJ's

$/mcf divided by .028328 = $\$/10^3m^3$

$/MMBtu divided by 1.055056 = $/GJ

$/GJ times MJ/m^3 = $\$/10^3m^3$

Enbridge Gas Distribution Inc. assumes a heat content of 37.69 Mj/m^3

Witness: D. Small

GAS SUPPLY FUTURE CONSIDERATIONS

1. Enbridge Gas Distribution ("Enbridge" or "the Company") considers the long-term implications of its decisions throughout its gas supply planning process. There are often projects proposed or under development which have the potential to impact the Company's future gas supply planning options. There are also proposals and discussions from government and industry that can impact the landscape of the natural gas market in which Enbridge operates. For these reasons, Enbridge monitors projects and other developments closely.

2. This evidence provides information about known and expected new infrastructure projects and about trends, policies, proceedings and plans that may impact on Enbridge's future gas supply planning options.

Contract Terms – Renewals and New Facilities

3. Contract terms for transportation capacity that requires the construction of new facilities are often different from those that utilize existing pipeline capacity. Acquiring transportation capacity generally requires a longer contract term commitment if new capital investment is required, as compared to contracting on existing infrastructure which may not require as great a commitment.[1]

Natural Gas Infrastructure Projects

4. The following list of projects could impact Enbridge's gas supply planning options in the future. This list is not intended to be exhaustive and the Company is not requesting preapproval of the cost consequences related to the projects that are discussed. The intent of the following is to provide some context in relation to the projects that have the potential to impact Enbridge's gas supply planning.

[1] For further discussion on transportation contracting decisions, see the "Transportation Portfolio" section in Exhibit D1, Tab 2, Schedule 2, Section 2.4.

<u>NEXUS Pipeline</u>

5. The NEXUS Gas Transmission Project ("NEXUS") is a proposed pipeline that will provide natural gas markets in Ohio, Michigan, Chicago, and the Dawn Hub in Ontario with a direct link to natural gas located within the Appalachian basin. The 1.5 Bcf per day (1,601,514 GJ per day) project requires the construction of approximately 410 kilometres of new greenfield pipeline and includes the efficient use of existing and expanded transportation capacity along the Texas Eastern Transmission, LP system in Ohio, the DTE Pipeline Company ("DTE") gas transportation system in eastern Michigan, and the Vector Pipeline system in southeastern and eastern Michigan, northern Indiana, eastern Illinois and western Ontario.

6. NEXUS helps to diversify supply being transported to Dawn by offsetting Chicago supply with supply from the Appalachian basin.

7. Enbridge has entered into a Precedent Agreement with the lead developers of NEXUS, DTE and Spectra Energy Transmission, LLC, for 110,000 Dth per day (116,056 GJ per day) of firm transportation capacity scheduled to start in 2017.

8. Preapproval of the cost consequences for the long-term transportation capacity with NEXUS was approved by the Ontario Energy Board ("the Board") in EB-2015-0175.

Witnesses: M. Kirk
D. Small

King's North Project

9. The King's North Project consists of approximately 11km of new natural gas pipeline that will connect the Albion Pipeline (also referred to as Segment A of Enbridge's GTA Project) to TCPL Mainline through interconnects at Albion Station and west of the Maple compressor station. This project underpins elections made by Enbridge in TCPL's 2016 New Capacity Open Season ("NCOS") to replace 166,000 GJ per day of non-renewable firm transportation from Empress to the Enbridge EDA with 170,000 GJ per day of renewable firm transportation from Parkway to the Enbridge EDA. The King's North Project is also required to implement Phase 2 of the Dawn Access Settlement Agreement.[2]

10. The project had a target in-service date of November 1, 2016 which was recently delayed to the end of November 2016. In the event of a delay, Enbridge has conditionally extended the non-renewable firm transportation that is being replaced until the earlier of November 1, 2017 or the implementation of the King's North Project.

Vaughan Mainline Expansion Project

11. The Vaughan Mainline Expansion Project includes approximately 12km of new natural gas pipeline which will connect into the King's North Project and existing TCPL Mainline, providing a loop between King's North and the Maple Compressor Station. The project was approved by the National Energy Board ("NEB") on August 4, 2016 and has a target in-service date of November 1, 2017. This project underpins elections made by Enbridge in TCPL's 2017 NCOS which includes 171,066 GJ per day of new short-haul capacity from Parkway of which 97,845 GJ per day will be converted from currently contracted long-haul capacity.

[2] King's North is part of the "Downstream Infrastructure" referred to in the Phase 2 Preconditions in EB-2014-0323

This capacity will be used to meet system supply demand and to facilitate Phase 2 of the Dawn Access Settlement Agreement.[3]

12. In the event of a delay to the Vaughan Mainline Expansion Project, Enbridge has negotiated a conditional extension to the conversion from long haul to short haul until the earlier of October 31, 2018 or until all necessary assets for incremental short haul transportation are in-service.

<u>Constitution Pipeline</u>

13. The Constitution Pipeline proposes to transport natural gas produced in northern Pennsylvania (650,000 Dth or 685,786 GJ per day) through the state of New York where it would interconnect with multiple pipelines, including the Iroquois Pipeline which, in turn, interconnects with TCPL in Waddington, near the Enbridge EDA.

14. The Federal Energy Regulatory Commission ("FERC") issued a certificate of public convenience and necessity for the Constitution Pipeline in December 2014. Since that time, however, planning and construction of the pipeline has been mired in controversy.[4] In July 2016, FERC approved a request from Constitution Pipeline for an additional two years to complete the pipeline, extending the deadline from December 2016 to December 2018.

15. The completion of Constitution Pipeline would increase the viability of importing United States shale gas directly into eastern Ontario and provide an opportunity to diversify the Company's supply portfolio, particularly for the Enbridge EDA. Specifically, natural gas transported on the Constitution and Iroquois Pipelines

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[3] The Vaughan Mainline Expansion Project is part of the "Downstream Infrastructure" referred to in the Phase 2 Preconditions in EB-2014-0323

[4] The Constitution Pipeline webpage tracks news developments here: http://constitutionpipeline.com/news/

could increase the liquidity of the Iroquois trading hub which would make it a more reliable and cost effective source of supply in the future.

Rover Pipeline

16. The proposed Rover Pipeline would transport 3.25 Bcf per day (3,469,948 GJ per day) from processing plants in West Virginia, eastern Ohio and western Pennsylvania for delivery to markets around the United States via interconnects with existing pipelines. The primary consideration for Enbridge is that Rover is expected to transport up to 1,100,000 Dth per day (1,160,562 GJ per day) to "Market Zone North" – a delivery point on Rover which encompasses the delivery points of Dawn, PEPL North, and Vector. This is expected to have a positive impact on the liquidity at the Dawn Hub.

Other Developments

Enbridge Requirement at Dawn

17. While Enbridge has taken steps to diversify its gas transportation portfolio through increased short haul transportation capacity from Dawn to the franchise area, there is also a benefit to diversifying supply options upstream of Dawn through alternative means. In the near-term, that may include exploring opportunities such as contracting for incremental capacity on the NEXUS[5] and Link pipelines[6], as described elsewhere in the 2017 test year evidence. In the longer-term, additional diversity at Dawn could be achieved through contracting for new transportation services, such as TCPL's long-term fixed-price service described in the section below, or through the acquisition of supply at points other than Dawn such as

[5] NEXUS deliveries to Dawn offset Chicago deliveries since Vector capacity is utilized
[6] 2017 arrangements utilizing the Link Pipeline are discussed at Exhibit D1, Tab 2, Schedule 3, Paragraphs 14 and 21

Iroquois should it become a more liquid hub (as discussed in the Constitution Pipeline section above).

TCPL's Long-Term Fixed-Price Service[7],[8]

18. TCPL has discussed the potential for a new long-term fixed-price tolling structure to help natural gas producers in Western Canada compete with producers in the United States northeast. The service will be available to shippers through 10 year contracts. TCPL has indicated the service would be priced to attract incremental supply, resulting in more throughput than would otherwise occur. The incremental utilization of the Mainline could lead to a reduction in tolls for other TCPL services and the incremental supply being transported to Dawn would help to meet an increasing requirement for supply at Dawn.

Cap & Trade and Environmental Regulation

19. Enbridge recognizes the Government of Ontario's efforts to reduce Greenhouse Gas ("GHG") emissions and is committed to helping the Province meet its GHG reduction targets. As part of its emissions reduction program, the Government has passed legislation to establish a Cap and Trade program, set to commence in January 2017.

20. In March 2016, the Ontario Energy Board ("OEB") initiated a consultative process to "develop a natural gas regulatory framework" and "guide the OEB's assessment of natural gas distributors' Cap and Trade Compliance Plans, including the cost

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[7] http://www.theglobeandmail.com/report-on-business/industry-news/energy-and-resources/transcanada-aims-to-launch-discount-toll-system-by-2017/article31172664/ and http://www.bloomberg.com/news/articles/2016-07-21/transcanada-prepares-to-court-bids-for-cheaper-mainline-gas-toll

[8] TCPL's response to Information Request NEB 3.1 in RH-001-2016

consequences of these plans and the mechanism for recovery of costs in rates."[9] Enbridge continues to work with the Board in developing the framework.

21. On June 8, 2016, the Ontario government released its Climate Change Action Plan ("CCAP"), outlining the approach to addressing climate change and the investment of funds collected through the Cap and Trade program. The CCAP, legislation, and regulation can be accessed on the government of Ontario webpage.[10] Initiatives discussed in the CCAP that could impact Enbridge and its customers include, *inter alia*:
    - Investments in Natural Gas Vehicle infrastructure;
    - Commitments to renewable natural gas as part of the energy mix; and
    - Changes to building codes to achieve "net-zero carbon emissions" for new homes and small buildings.

22. Currently, it is not clear how the implementation of the Cap and Trade Program and the CCAP will impact on future natural gas consumption. Enbridge will continue to work with the Government on these issues and others that have the potential to impact the Company and its customers.

<u>TCPL's Proposal to Modernize Storage Transportation Service</u>

23. In February 2016, TCPL filed an application with the NEB seeking amendments to the Storage Transportation Service ("STS") effective April 1, 2017. As a companion service to long haul FT service, STS provides transportation to and from a storage location and is used to manage both seasonal and daily fluctuations in demand.

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[9] Cap and Trade Initiation Letter filed in EB-2015-0363
[10] https://www.ontario.ca/page/climate-change-action-plan
https://www.ontario.ca/laws/statute/s16007
https://www.ebr.gov.on.ca/ERS-WEB-External/displaynoticecontent.do?noticeId=MTI3ODA1&statusId=MTk0NDU3&language=en

Enbridge has relied on STS as part of its gas supply portfolio for more than 25 years.

24. Enbridge is actively participating in the proceeding and has estimated that the amendments could cause approximately $1 million in annual incremental transportation costs under the Company's current gas transportation portfolio. The incremental costs may be mitigated post 2020 once Enbridge's commitment to maintain 265,000 GJ per day of long-haul firm transportation on the Mainline expires.

25. Information related to this proceeding can be found in NEB Hearing Order RH-001-2016.

Western Canadian Liquefied Natural Gas Exports

26. There are 20 Liquefied Natural Gas ("LNG") export projects proposed for the British Columbia coast which aim to export LNG primarily to Asian and South American markets, using gas supply from the Western Canadian Sedimentary Basin ("WCSB"). 18 of the 20 projects have been granted export licenses by the NEB, amounting to a total capacity of 306.4 million tonnes per year (for context, current global LNG trade is approximately 245 million tonnes per year). The LNG export projects will face challenges which include competing with established market participants such as the United States and Australia. Should the LNG export project(s) come into effect, WCSB supply available for transportation to eastern Canada will be reduced, all else being equal.

National Fuel's Northern Access 2016 project

27. National Fuel's Northern Access 2016 project will add 490 MMcf per day (523,161 GJ per day) of capacity to TCPL's Chippawa receipt point.

Witnesses: M. Kirk
D. Small

The project was originally slated for an in-service date of November 1, 2016, but due to a difficult regulatory environment, tight construction timelines, and depressed natural gas prices reducing future supply expectations, National Fuel delayed the in-service date of the project to November 1, 2017.

28. However, following the announcement of the project's delay in February 2016, National Fuel announced in June 2016 that it has arranged with its subsidiary, Seneca Resources, to jointly develop wells in order to bring supply to the Northern Access 2016 project. Despite that, there remains the challenge of gaining regulatory approval for construction of the project.

29. The supply to be imported at Chippawa can be transported to Dawn via the TCPL Mainline and Union system.

<u>2018 TCPL Toll Review</u>

30. In its RH-001-2014 Decision, the NEB approved TCPL's current tolls, and associated Tariff changes, to be in place until December 31, 2020, subject only to a limited toll review prior to 2018 for the 2018 to 2020 period. The intention of the review is to update tolls for changes to revenue requirements and billing determinants.

31. The NEB directed TCPL to file an application prior to December 31, 2017 for approval of tolls for the 2018 to 2020 period. Enbridge will review the tolling implications and actively participate in the proceeding if appropriate.

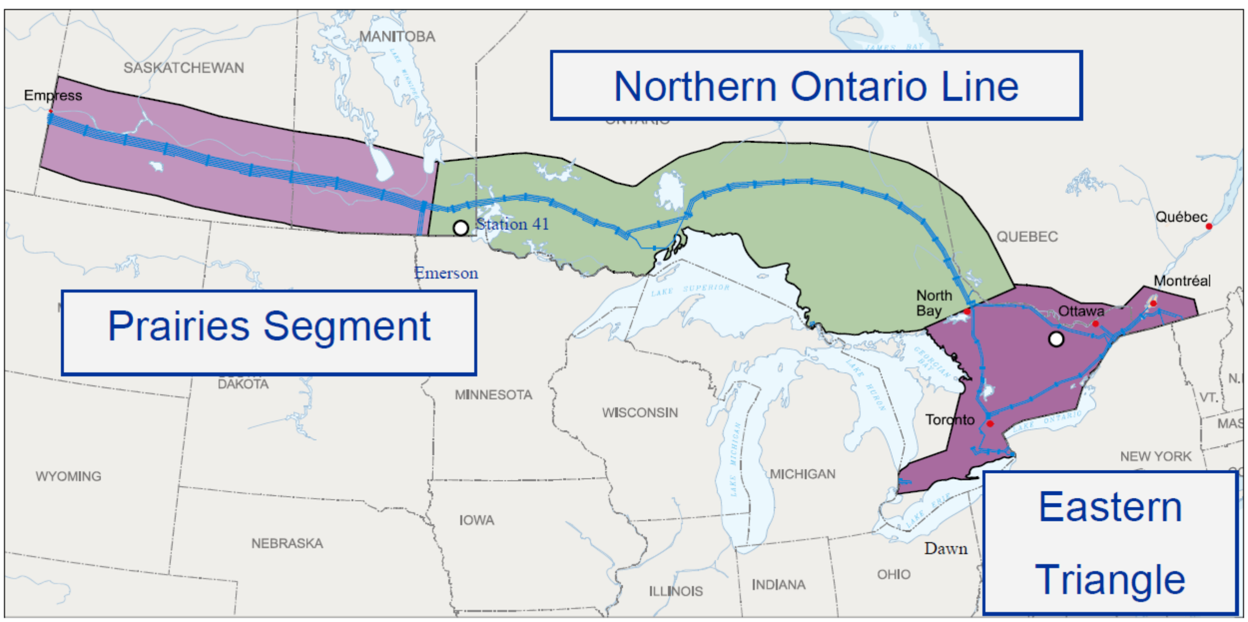
<u>TCPL Mainline 2013-2030 Settlement Agreement</u>

32. In the Settlement Agreement to RH-001-2014, Enbridge agreed to hold long-haul contracts with a minimum contract quantity of 265,000 GJ per day during the period

of January 1, 2015 to December 31, 2020. Also stated in the Settlement Agreement is that Mainline Shippers must notify TCPL of conversion from long-haul capacity to short-haul capacity three years in advance of the requested commencement date.[11] As per these conditions of the Settlement Agreement, Enbridge will evaluate its post-2020 requirements and communicate its intentions to TCPL in the coming year.

33. In the RH-001-2014 Decision, the NEB approved segmentation tolling parameters in principle as the basis for establishing Mainline tolls post-2020. The segmentation is expected to separate cost of service and throughput data, for toll design purposes, between the Prairies Segment, Northern Ontario Line, and the Eastern Triangle as illustrated in Figure 1.

Figure 1 – Segments of the TCPL Mainline



[11] This provision is specific to situations where existing capacity is not available for long-haul to short-haul conversion

34. Enbridge intends to actively participate in TCPL's post 2020 tolls proceeding to ensure that the tolls associated with a significant portion of its gas transportation portfolio are appropriate.

Incremental Storage

35. In the Settlement Agreement to EB-2015-0122, Enbridge agreed to perform a detailed review of the need for incremental storage in future years with the support of an external consultant. Consistent with the Settlement Agreement, the Company has retained a consultant for the purpose of reviewing its potential incremental storage requirements.

Heat Value

36. For the purposes of developing its 2017 gas supply costs, the Company has used a conversion factor of 37.69 MJ/m^3, which is consistent with prior years. However, more recently, the heat value of gas received by Enbridge has had a consistently higher heat value, averaging closer to 38.00 MJ/m^3. The Company is in the process of investigating whether or not there needs to be a change to the heat value conversion factor used in the budgeting process and will indicate its plans in due course.

Witnesses: M. Kirk
D. Small

2017 CUSTOMER CARE / CIS UPDATE

1. In September 2011, Enbridge Gas Distribution (“Enbridge” or the “Company”) presented to the Ontario Energy Board (the “Board”) for approval, a Settlement Agreement within the EB-2011-0226 proceeding for the establishment of Enbridge’s Customer Care and Customer Information System (“CC/CIS”) costs for the period of 2013 through 2018. On September 8, 2011 the Board approved the Settlement Agreement, a copy of which is filed at Exhibit D1, Tab 3, Schedule 2.

2. As specified in the “Terms of the Settlement” at page 11, the revenue requirement for all CIS and CC services for each particular year within the Settlement Agreement is to be determined by multiplying the forecast number of customers for that year “(which forecast will be set as part of the annual rate setting processes)” by the agreed and Board approved cost per customer as shown on page 12 of the Settlement Agreement and Line 17a of the updated Template, which is shown on page 43 of the Settlement Agreement. In addition, the amount of revenue requirement to be recovered was agreed to and approved to be smoothed into rates which would be determined annually by multiplying the forecast number of customers for that year by the smoothed revenue requirement per customer as shown on page 12 of the Settlement Agreement and Line 24 of the updated Template shown on page 43 of the Settlement Agreement. As indicated at pages 21 and 22 of the Settlement Agreement, the definition of “customer” to be used for determining the CC/CIS revenue requirement is that which is used in the Accenture Customer Care Service Agreement (which is different from the definition of “customer” used elsewhere in this Application, because Accenture includes both active and locked customers).

Witnesses: D. McIlwraith
R. Small

3. As was reflected and documented within the EB-2011-0354, EB-2012-0459, EB-2014-0276, and EB-2015-0114 proceedings, due to the distinct features of the CC/CIS Settlement Agreement it is necessary to separately display the approved revenues, costs, and resulting revenue requirement specific to CC/CIS from all other regulated utility revenues, costs, and their related revenue requirement. This is necessary to provide assurance that the levels of revenues and costs approved within the CC/CIS Settlement Agreement are appropriately reflected within Enbridge's annual rate applications and rate setting model. The separation of CC/CIS also ensures that the determination and the required rate impact associated with all other remaining Enbridge revenues and costs are not impacted by, and do not alter the CC/CIS revenue requirement amounts derived and approved as per the CC/CIS Settlement Agreement.

4. Within Enbridge's 2013 rate application, EB-2011-0354, the Company applied for and received approval for the 2013 rate making implications of the EB-2011-0226 Settlement Agreement as seen within the Final Rate Order, Appendix A, page 1.

5. Within Enbridge's 2014 to 2018 Customized Incentive Regulation rate application, EB-2012-0459, the 2014 to 2018 revenue requirements for CIS and CC services, and the corresponding smoothed revenue requirements to be recovered in rates, were revised to reflect updated customer forecasts, as per the terms of the Settlement Agreement. The 2014 rate making implications were approved, as seen within the Decision and Rate Order, Appendix A, page 1 of 40. The updated 2015 to 2018 revenue requirements for CIS and CC services and corresponding smoothed revenue requirements were included within 2015 to 2018 preliminary Allowed Revenue as placeholder amounts to be updated in rate adjustment applications for each of those years.

6. Similar to the updates performed in Enbridge's 2015 Rate Adjustment proceeding EB-2014-0276, and 2016 Rate Adjustment proceeding EB-2015-0114, this Application includes the implementation of the EB-2011-0226 Board-approved CC/CIS Settlement Agreement for 2017, and replaces the 2017 placeholder amounts presented in EB-2012-0459. Exhibit D1, Tab 3, Schedule 3 provides an updated 2017 CC/CIS Template, in which Enbridge has updated the 2017 forecast number of customers shown at Row 25, Column L, as compared to the previously updated Template filed within EB-2012-0459, at Exhibit D1, Tab 10, Schedule 3, which included a 2017 placeholder forecast number of customers. The resulting updated annual Total CIS and Customer Care costs and Allowed Revenue for 2017 are shown on Lines 26 and 27 of the updated Template. The updated 2017 costs, of $123.8 million are calculated by multiplying the Board-approved Total cost/Customer of $57.08 (updated Template, Row 17a, Column L) by Enbridge's updated forecast of "customers" for 2017, of 2,168,434 (updated Template, Row 25, Column L). The updated 2017 Allowed Revenue amount, of $126.6 million, is calculated by multiplying the Board-approved 2017 Normalized Customer Care Revenue Requirement per customer, of $58.36 (updated Template, Row 24, Column L), by the updated forecast of "customers" for 2017, again 2,168,434.

7. As a result of updating the 2017 forecast number of customers, the updated Total CIS and Customer Care costs of $123.8 million, and corresponding Allowed Revenues of $126.6 million, are each $2.0 million lower than the 2017 placeholder amounts of $125.7 million and $128.6 million. The 2017 placeholder amounts were calculated within EB-2012-0459 at Exhibit D1, Tab 10, Schedule 3, Rows 26 and 27, Column L, and utilized within the 2017 placeholder allowed revenue and deficiency determination (EB-2012-0459 Decision and Rate Order, Appendix A, page 25 of 40, Rows 20 and 22, Column 4). The reduction in the updated Total CIS

and Customer Care costs and corresponding Allowed Revenues have been incorporated into the calculation of 2017 Updated Forecast allowed revenues and deficiency, as seen within Exhibit F1, Tab 2, Schedule 1, Columns 2, 5, and 7.

8. The updated Customer Care and CIS Allowed Revenue to be recovered in 2017 rates, is an increase (deficiency) of approximately $4.2 million as compared to the 2016 approved Customer Care and CIS Allowed Revenues included in 2016 rates, or 2017 revenues at existing rates. This can be seen by comparing the updated 2017 Allowed Revenue of $126.6 million, shown in the updated Template at Exhibit D1, Tab 3, Schedule 3, Row 27, Column L, to the 2016 approved Allowed Revenue of $122.4 million, also shown in the updated Template at Exhibit D1, Tab 3, Schedule 3, Row 27, Column K. This increase is also reflected in the 2017 Updated Forecast Allowed Revenue and Deficiency calculation shown at Exhibit F1, Tab 2, Schedule 1, Row 28 (and 33), Column 7.

SETTLEMENT AGREEMENT

Enbridge Gas Distribution Customer Care and Customer Information System costs for 2013 to 2018

September 2, 2011

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PREAMBLE

This Settlement Agreement is filed with the Ontario Energy Board (the “OEB” or the “Board") in connection with the application of Enbridge Gas Distribution Inc. (“Enbridge” or the “Company”), for an order or orders approving a Template setting out Enbridge’s customer care (“CC”) and Customer Information System (“CIS”) costs, and associated component of revenue requirement for the period from 2013 to 2018 (the “Application”).

In Procedural Orders No. 1 and 2, the Board established the process to address this Application, as well as the Issues List for this proceeding. The evidence for this application comes from four sources: (i) Enbridge’s prefiled evidence; (ii) answers to interrogatories from Board Staff and intervenors; (iii) evidence from a technical conference held August 17, 2011; and (iv) additional evidence provided following the technical conference through undertakings given at and after the technical conference, including information provided during the Settlement Conference and subsequently placed on the public record by agreement between the parties.

A Settlement Conference was held on August 23 to 26, 2011. George Dominy acted as the OEB-appointed facilitator for the Settlement Conference. This Settlement Agreement arises from the Settlement Conference and subsequent discussions.

Enbridge and the following intervenors, as well as Ontario Energy Board technical staff (“Board Staff”), participated in the Settlement Conference:

BUILDING OWNERS AND MANAGERS ASSOCIATION OF THE GREATER TORONTO AREA (BOMA)
CANADIAN MANUFACTURERS & EXPORTERS (CME)
CONSUMERS COUNCIL OF CANADA (CCC)
ENERGY PROBE RESEARCH FOUNDATION (Energy Probe)
FEDERATION OF RENTAL-HOUSING PROVIDERS OF ONTARIO (FRPO)
SCHOOL ENERGY COALITION (SEC)
VULNERABLE ENERGY CONSUMERS COALITION (VECC)

The Settlement Agreement deals with all of the issues on the Board’s "Issues List” that is set out in Procedural Order No. 2. As required by the Board’s Procedural Order No. 1, this Settlement Agreement also includes a detailed explanation and justification for the settlement of each issue, including a full discussion of the evidentiary basis upon which the settlement was reached.

All intervenors listed above participated in the Settlement Conference and subsequent discussions. Board Staff takes no position on any issue and, as a result, is not a party to the Settlement Agreement. Enbridge and all intervenors have agreed to the settlement of all of the issues on the Issues List, as described on the following pages. The description of each issue assumes that all parties participated in the negotiation of the issue, unless specifically noted otherwise.

Best efforts have been made to identify all of the evidence that relates to each settled issue. The supporting evidence for each settled issue is identified individually by reference to its exhibit number in an abbreviated format; for example, Exhibit B, Tab 3, Schedule 1 is referred to as B-3-

1. The identification and listing of the evidence that relates to each settled issue is provided to assist the Board.

The Settlement Agreement describes the agreements reached on the issues. The Settlement Agreement contains explanation of the evidence supporting and relating to each issue. In addition, the Settlement Agreement provides a direct link between each settled issue and the supporting evidence in the record to date. In this regard, the parties are of the view that the evidence provided is sufficient to support the Settlement Agreement in relation to the settled issues and, moreover, that the quality and detail of the supporting evidence, together with the corresponding rationale, will allow the Board to make findings agreeing with the proposed resolution of the settled issues. In the event that the Board wishes further evidentiary support with respect to any of the issues, the parties will have available witnesses from both Enbridge and the intervenors to provide such support through oral evidence.

According to the Board's *Settlement Conference Guidelines* (p. 3), the parties must consider whether a settlement proposal should include an appropriate adjustment mechanism for any settled issue that may be affected by external factors. Enbridge and the other parties who participated in the Settlement Conference consider that no settled issue requires an adjustment mechanism other than those expressly set forth herein.

None of the parties can withdraw from the Settlement Agreement except in accordance with Rule 32 of the *Ontario Energy Board Rules of Practice and Procedure*. Finally, unless stated otherwise, a settlement of any particular issue in this proceeding is without prejudice to the positions parties might take with respect to the same issue in future proceedings. However, any such position cannot have the effect of changing the result of this Agreement.

It is acknowledged and agreed that none of the provisions of this Settlement Agreement are severable. If the Board does not, prior to the commencement of the hearing of the evidence in this proceeding, accept the provisions of the Settlement Agreement in their entirety, there is no Settlement Agreement (unless the parties agree that any portion of the Settlement Agreement that the Board does accept may continue as a valid Settlement Agreement).

BACKGROUND

Through this Application, Enbridge is seeking approval of its annual revenue requirement – cost-based and then smoothed - for CC and CIS services, for the years from 2013 to 2018. The parties are pleased to advise the Board that, through the settlement process and preceding extensive consultation process, agreement on an overall CC/CIS revenue requirement of $735 million for those six years has been achieved, with total annual increases in costs per customer from 2013 to 2018 of 0.6% per year, and amelioration of the jump in cost per customer from 2012 to 2013 through a smoothing mechanism.

Effectively, this Application seeks an amendment, update and extension to a Settlement Agreement approved by the Board in the EB-2006-0034 proceeding, in respect of CC and CIS costs for the 2007 to 2012 period (the “2007 Settlement Agreement”).[1] The 2007 Settlement Agreement set out the Company’s CC and CIS costs for 2007 to 2012 (organized by category in an attached template), as well as a smoothed annual revenue requirement for the sum of those costs in each year. The extended and expanded Template (the “2013 Template”) attached to this Application as Ex. A-2-2 uses the same approach and sets out the Company’s forecast CC and CIS costs, and associated annual revenue requirement, for the 2013 to 2018 period.
The 2007 Settlement Agreement was reached after a lengthy, intense and successful consultative process between Enbridge and stakeholders. Throughout that consultative process, Enbridge worked principally with a stakeholder steering committee consisting of representatives from Consumers Council of Canada (“CCC”), Industrial Gas Users Association (“IGUA”)[2] and School Energy Coalition (“SEC”), who had been selected by the larger stakeholder community to represent their interests. As described in the letter from counsel to CCC to the Board dated July 25, 2011, the previous consultative process came about after Enbridge’s previous failed attempts to get approval for a new CIS resulted in the Board suggesting that the Company and intervenors should try to work cooperatively on a solution that would avoid another lengthy and expensive hearing. The consultative process was also intended to address the disagreements and acrimony resulting from Enbridge’s then-current contract to receive CC services from an affiliate (CustomerWorks Limited Partnership).

The consultative’s main purpose in the 2007 process was to provide Enbridge with stakeholder feedback and guidance throughout the design, tendering and contracting phases of the CC and CIS initiatives, with the objective of leading to a consensus proposal for review by the Ontario Energy Board (the “OEB” or the “Board”). Ideally, the process would meet the interests of Enbridge and ratepayers in allowing Enbridge to proceed with necessary long-term plans for its customer care operations, including the acquisition of a new computer system to manage billing functions (the new CIS asset).

Ultimately, that 2007 consultative process led to a resolution of most of the regulatory and ratemaking issues related to the procurement of new CC and CIS services and the provision of CC services. This allowed Enbridge, with stakeholder support, to procure a new CIS and to enter

[1] Exhibit N1, Tab 1, Schedule F in the EB-2006-0034 proceeding. Filed in this proceeding as Ex. I-1-33.

[2] The lawyers who had participated in the Steering Committee on behalf of IGUA subsequently (in mid-2007) became the representatives of Canadian Manufacturers & Exporters (“CME”) and thereafter participated in the Steering Committee on behalf of CME.

into a contract with Accenture Business Services for Utilities ("Accenture" or "ABSU") for the provision of CC services for a five year term.

A fundamental component of the resolution was the agreement among all parties that the overall CIS and CC costs to be incurred during the then-current year (2007) and the expected five year incentive regulation ("IR" or "IRM") period that would follow (2008-2012) would be summed together and then smoothed over the entire six year period. The six year term of the settlement allowed the Company to proceed to award long term contracts for a new CIS asset and to a new CC service provider. Through the settlement, Enbridge benefitted from several years of budget predictability in this important area, with broad freedom to optimize operational decisions. The ratepayers benefitted from minimal increases in costs, and low, gradual, and controlled rate impacts.

The 2007 Settlement Agreement that was prepared by the consultative group endorsed Enbridge's plans to acquire and operate a new CIS asset, and to enter into new CC arrangements with a third party provider for the years from 2008 to 2012. The 2007 Settlement Agreement reflected the successful transparent, open and collaborative approach undertaken by the Company with ratepayer representatives, which allowed those representatives to assure themselves, their clients, and the other intervenor groups that the costs sought for recovery were reasonable and appropriate. The 2007 Settlement Agreement was approved by the Board during a hearing on March 22, 2007.[3] In approving the 2007 Settlement Agreement, the Board highlighted the approach used by stakeholders to sum together all costs over six years and create a "smoothed" annual revenue requirement, and noted that "we are impressed by the drafting of this agreement and the sophistication of the process by which it was brought about".[4]

After that time, Enbridge continued to work with the stakeholder steering committee (now comprised of representatives of CCC, CME and SEC) and their expert advisor (Five Point Consulting LLC, referred to herein as "Five Point")[5] to discuss and review the implementation of the new CIS asset. That process took place in the months leading up to and following the implementation of the new CIS asset in September 2009. This continued engagement between Enbridge and ratepayer representatives was consistent with commitments made in the 2007 Settlement Agreement to ensure that the consultative group would monitor the procurement and implementation process for the new CIS.[6] This engagement concluded by around March 2010 with a final review and endorsement of the costs associated with Enbridge's new CIS.[7]

Starting around that same time (March 2010), Enbridge and the stakeholder steering committee also worked together on issues related to the procurement of CC services after the date when the current arrangement with Accenture terminates (April 1, 2012). Enbridge believed that the interests of all parties would be best served by having ratepayer representatives informed and

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[3] EB-2006-0034, 15 Tr. 85. Filed in this proceeding as Ex. I-1-34.

[4] EB-2006-0034, 15 Tr. 83-85. Filed in this proceeding as Ex. I-1-34.

[5] Five Point is the corporate successor to TMG Consulting, which was the expert advisor to the stakeholder steering committee in connection with the 2007 Settlement Agreement. For ease of reference, TMG Consulting and Five Point Consulting are both referred to as "Five Point" in this Application.

[6] 2007 Settlement Agreement, at p. 6: see Ex. I-1-33.

[7] Transcript from August 17, 2011 Technical Conference, at pp. 61-62.

involved in this process as it unfolded, rather than by seeking stakeholder endorsement after the fact. The reason why this process began in the winter of 2010, despite the fact that the current Accenture Customer Care Services Agreement ("CCSA") runs until March 31, 2012 is that there is a long lead time associated with the replacement of CC services and with notice provisions under the current CCSA. That long lead time is required to account for any request for proposal ("RFP") process that might be required and to account for the time and effort that would be required if a transition to a new service provider became necessary.[8]

This ongoing process between Enbridge and the stakeholder steering committee led to a number of developments in respect of the Company's CIS and CC arrangements. These developments are directly relevant and impactful to the amounts to be recovered for CIS and CC services in the years after the term of the current 2007 Settlement Agreement concludes (starting as of January 1, 2013). To the extent that these developments impact the actual costs paid by Enbridge for CIS and CC services before January 1, 2013, those impacts will <u>not</u> be included in Enbridge's revenue requirement for 2011 and 2012, since the values in the 2007 Template will continue to apply for the term of the 2007 Settlement Agreement (until December 31, 2012) as originally agreed.

The first development is that the Company's new CIS asset has now been successfully brought into service and all implementation costs associated with the new CIS asset (which has a ten year economic life) are known. These costs were reviewed and endorsed by the stakeholder steering committee as part of their original mandate to review the implementation of that asset. In advance of the filing of this Application, Enbridge and the stakeholder steering committee agreed on the final capital cost of the new CIS asset, and the resulting opening rate base amount for the new CIS asset as of January 1, 2013, when the 2007 Settlement Agreement comes to an end. The new opening rate base amount of $76.9M is modestly higher than the $71.4M amount indicated in the 2007 Settlement Agreement. Enbridge and the stakeholder steering committee also agreed on the revenue requirement that would result from the updated rate base value for the new CIS asset for the years from 2013 to 2018.

The second development is that a process has now been undertaken to proactively evaluate the Company's current CC arrangements, and future options for receiving CC services, in the interest of ensuring the best possible future arrangements for ratepayers and Enbridge. The goal of this process was to determine how best to obtain CC services in the years after April 1, 2012, when the current CCSA with Accenture expires. In consultation with the stakeholder steering committee, Enbridge implemented a multi-stage strategy in which it first sought to avoid the cost and disruption of an RFP by obtaining sufficiently attractive terms from the incumbent Accenture. Failing that, an RFP would be launched and competitive bids obtained.

This process was successful. Enbridge obtained favourable terms from the incumbent, thereby avoiding the substantial costs associated with an RFP and a transition to a new service provider. Enbridge has reached an agreement with Accenture, subject to approval by the Board, for an update and extension of the current CCSA for five years, with an option for two more years. In advance of the filing of this Application, Enbridge and members of the stakeholder steering committee agreed that the terms of the update and extension are reasonable and in the best interest of the Company and its ratepayers. Enbridge has agreed with Accenture to the update and extension of the current CCSA, conditional on receiving OEB approval for the recovery of

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[8] Ex. B-4-1, pp. 3-4.

costs that will be charged under that agreement. That approval must be received by September 15, 2011 in order for Enbridge to avoid having to negotiate for a temporary extension of the CCSA.

Having come to a tentative agreement on the prudence of the costs associated with the acquisition and implementation of the new CIS and with the extension of the CCSA, Enbridge and the stakeholder steering committee considered how best to approach obtaining regulatory approvals.

Enbridge and the stakeholder steering committee agreed upon two key items in that regard.

First, Enbridge and members of the stakeholder steering committee agreed that it is better to consider the CIS and CCSA costs agreed upon, not just in isolation, but in the context of Enbridge's broader CIS and CC costs for the 2013 to 2018 period. This provides a more complete context and allows for the Company's forecast ongoing costs to be evaluated on a consistent basis in comparison to current costs (which are set out in the Template filed as Ex. B-5-2). This was the purpose of the Template in the 2007 Settlement Agreement (the "2007 Template"), and it continues to be the most comprehensive way of ensuring a fair result. The way that this was effected was by extending the 2007 Template to include therein the Company's CIS and CC costs for the 2013 to 2018 period, upon which Enbridge and the steering committee have agreed, along with Enbridge's forecasts of other related CIS and CC costs for that time frame.

Enbridge's forecast CIS and CC costs for the 2013 to 2018 term are set out in the extended and expanded "2013 Template" that is included with this Application as Ex. A-2-2. Prior to the filing of the Application, Enbridge and members of the stakeholder steering committee agreed upon the values set out in rows 3 and 10(a) of the 2013 Template, which relate to the revenue requirement for the new CIS asset (line 3) and to the costs of the update and extension of the current CCSA, (line 10a). These lines represented $437M, or approximately 60% of the total costs in the 2013 Template. There was at that time no agreement to the values in the balance of the 2013 Template which represent Enbridge's forecasts of other related CIS and CC costs for that time frame (and which comprised about $321M of the six year costs).

Second, it was agreed that it was important and timely to immediately involve other stakeholders, and the OEB, in any further deliberations around Enbridge's CC and CIS costs. The intention was to first seek to achieve consensus agreement on the two items upon which Enbridge and the stakeholder steering committee had agreed (CIS capital costs and costs associated with the extended CCSA), and then to engage in deliberations related to the balance of Enbridge's CIS and CC costs as set out in the 2013 Template for the 2013 to 2018 period. Enbridge's stated objective was to discuss and negotiate all items in the 2013 Template to seek to reach a comprehensive agreement about Enbridge's CC and CIS costs for the 2013 to 2018 term.

The foregoing is the context for Enbridge's Application, which was filed on June 20, 2011.

One item of note in Enbridge's Application, as seen in the 2013 Template, is the fact that there is a substantial increase of approximately $21.7 million in forecast revenue requirement between 2012 and 2013. Explanation for this increase is set out in evidence at Ex. B-2-1 (para. 8) and Ex. JTC1.10. The main reason for the increase, accounting for approximately $14.4M per year in revenue requirement, relates to the smoothing of CIS revenue requirement. During the 2007 to

2012 period, the average annual CIS revenue requirements, as calculated through the 2007 Template, were relatively low. This is because during that period the Capital Cost Allowance ("CCA") provided tax timing benefits to be recognized through 2012 in relation to the CIS asset's ten year economic life. Under the smoothing approach used in the 2007 Template, all of the CCA timing benefit was spread through the first five years of the economic life of the CIS asset, with the result that the 2012 revenue requirement recovered in rates is, per the 2007 Settlement Agreement, intentionally lower than the actual forecast revenue requirement in that year. As of January 1, 2013, when all of the CCA benefit has been credited to the CIS revenue requirement during previous years, the annual CIS cost to be recovered in the remaining years of the asset's economic life will necessarily increase. Through the 2007 Settlement Agreement, all parties were aware that the annual CIS-related revenue requirement would increase substantially at the end of the term of the Settlement Agreement, and all parties agreed that Enbridge would recover the full revenue requirement associated with the new CIS, throughout its economic life.[9]

As part of the Application, Enbridge indicated the reasons why there is some urgency to the relief sought. This was further explained in a letter dated July 20, 2011 where the Company indicated that:

> The reason [for the urgency] is that Enbridge's current CCSA with Accenture expires on April 1, 2012, and six months' notice must be provided if Enbridge wishes to extend the term of the current CCSA. The extended and updated CCSA that Enbridge has negotiated with Accenture will take effect as of April 1, 2012, but only if OEB approval of the cost consequences of that agreement has been obtained prior to that date. As a result, unless Enbridge receives OEB approval by September 30, 2011, it will have to negotiate another shorter term extension of the current CCSA in order to ensure that customer care services will be in place as of April 1, 2012. Further, if no OEB approval is received by around December 2011, then Enbridge will have to initiate a fresh RFP process for customer care services as of April 1, 2014 (which is the last date provided for in any alternate extension of the current CCSA), because of the lead time associated with such a process. That lead time would cover the RFP process, and any necessary transition to a new service provider. This step will be required even if Board approval of the extension and update of the current CCSA is still under consideration, because Enbridge will have to protect itself and ratepayers against the possibility that Board approval is not ultimately granted.
>
> These timing issues could have substantial financial and other impact on Enbridge and its ratepayers.

In recognition of the urgency of this Application, the Board created an expedited process. That process allowed for parties to review and ask questions about Enbridge's prefiled evidence through Interrogatories and a Technical Conference. Parties also had the opportunity, as part of the Technical Conference, to ask questions of the expert who supported the activities of the stakeholder steering committee (Five Point). This process culminated in a Settlement Conference held in late August 2011, which resulted in agreement on all matters in issue in this Application.

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[9] 2007 Settlement Agreement, at p. 13, filed as I-1-33.

TERMS OF THE SETTLEMENT

All parties have agreed upon Enbridge's revenue requirement for CIS and CC services for the period between 2013 and 2018, on a cost per customer basis. This means that for each year from 2013 to 2018, Enbridge's total revenue requirement for all CIS and CC services set out in the Template (which do not include bad debt costs) will be determined by multiplying the cost per customer set out in this Settlement Agreement for each particular year by the forecast number of customers for that year (which forecast will be set as part of the annual ratesetting processes). It should be noted that the customer forecast to be used for this purpose will be different from the other customer forecasts used in annual ratesetting processes, because the customer forecast to be employed for the purpose of setting annual revenue requirement pursuant to the Updated 2013 Template will use the definition of "customer" from the Accenture CCSA which includes both active and locked customers (hereinafter in this Settlement Agreement, the use of the term "Customer" is intended to refer to the definition of "Customer" from the Accenture CCSA).[10] The financial consequences of this Settlement Agreement are set out in an updated version of the 2013 Template (referred to herein as the "Updated 2013 Template"), which is attached to this Settlement Agreement as Appendix "A". The Updated 2013 Template does not include lines 18 to 22, which were in the 2007 Template, because the normalization and true-up process that was used to calculate normalized annual revenue requirements for 2007 to 2012 is no longer applicable.

As noted, this settlement is premised on an agreed cost per Customer for CIS and CC services (exclusive of bad debt costs) for each year over the 2013 to 2018 term. This cost per Customer was derived by: (i) all parties accepting, on a cost per Customer basis, the amounts negotiated between Enbridge and the stakeholder steering committee for the new CIS capital costs (line 3) and the costs associated with the revised and extended Accenture CCSA (line 10a)[11]; (ii) reducing Enbridge's 2013 forecast of all other CIS and CC costs in the 2013 Template (lines 4, 5, 6, 10b, 10c 11 and 12) by $2 per Customer (just under 10%); (iii) summing together the CIS, CCSA and all other CC costs per Customer to create an overall cost per Customer for 2013; and (iv) applying an annual inflation factor of 0.6% to the overall CIS and CC cost per Customer for each year from 2014 to 2018. Using Enbridge's current forecast of Customer numbers for the 2013 to 2018 period, as set out at line 17 of the Updated 2013 Template, the total revenue requirement associated with the agreed upon costs per Customer (as inflated each year) would be $735M. That represents a reduction from the $758M set out in Enbridge's Application (see Ex. A-2-2). It must be noted that the actual revenue requirement to be recovered by Enbridge over the 2013 to 2018 term will be different from $735M. That is because the forecast number of Customers each year will be different (at least to some extent) from Enbridge's current forecast. All parties agree that the reductions to base cost forecasts and the inflation factors used in this Settlement Agreement are not intended to be precedents for other Enbridge proceedings and are without prejudice to the position that any party may take on similar matters in future Enbridge proceedings.

[10] The definition of "Customer" to be used for this purpose is discussed below in the subsection titled "Annual Revenue Requirement".

[11] As explained below, Enbridge's costs related to Large Volume Billing have been moved from line 10a, where those costs were found in the 2013 Template filed with the Application at Ex. A-2-2, to line 12 (Enbridge backoffice costs) in recognition of the fact that the related services are now provided by Enbridge, and not by Accenture.

The agreed cost per Customer, which is set out at line 17a of the Updated 2013 Template, ranges from $55.75 in 2013 to $57.42 in 2018. The parties have agreed that the cost per Customer amount will be smoothed over the term, to temper the increase in cost per customer from 2012 (the end date of the 2007 Template) to 2013. The smoothed cost per Customer, which is set out at line 24 of the Updated 2013 Template, ranges from $53.50 in 2013 to $59.65 in 2018. For ease of reference, the cost per Customer amounts set out in the Updated 2013 Template are reproduced below:

	2013	2014	2015	2016	2017	2018
Line 17a Total cost/Customer	$ 55.75	$ 56.08	$ 56.41	$ 56.74	$ 57.08	$ 57.42
Line 24 (Smoothed) Revenue Req't/Customer	$ 53.50	$ 54.68	$ 55.88	$ 57.11	$ 58.36	$ 59.65

All parties have agreed that Enbridge should be given the ability to create a rate smoothing deferral account, which will capture the difference between Enbridge's forecast CIS and CC costs each year versus the smoothed amount forecast to be collected in revenue requirement. In the early years of the 2013 to 2018 term, the balance in that deferral account will grow (because Enbridge's agreed cost per Customer will be higher than the smoothed cost per customer being collected), and then in the later years the balance will decline (because Enbridge's agreed cost per customer will be lower than the smoothed cost per Customer being collected). Enbridge will be entitled to collect interest on balances in the rate smoothing deferral account (at a fixed annual rate of 1.47%), and will clear any amount remaining in the deferral account to or from customers, as the case may be, by normal application to the Board at the end of 2018.

The details of the settlement are set out in the balance of this "Terms of the Settlement" section of the Settlement Agreement. The following sections of the Settlement Agreement set out how the evidence filed supports the settlement, and address how the parties have resolved each of the issues on the Board's Issues List.

A. CIS costs (line 3 of Updated 2013 Template)

All parties agree to a $76.9M opening rate base value for the new CIS asset as of January 1, 2013, based upon the costs associated with the acquisition and implementation of the new CIS. All parties further agree, on a cost per Customer basis, to the revenue requirement to be recovered for the new CIS asset over the 2013 to 2018 term, which totals approximately $137M. That amount is set out at line 3 of the Updated 2013 Template, and is based upon the updated $76.9M opening rate base value for the new CIS asset as of January 1, 2013. That revenue requirement has been converted to a cost per Customer, based on Enbridge's forecast of Customers as set out at line 17 of the Updated 2013 Template. The CIS asset cost per Customer is a component of the overall annual cost per Customer that is set out in line 17a. The context and basis for this agreement is set out in the following paragraphs.

Through the 2007 Settlement Agreement, the parties endorsed Enbridge's acquisition of a new CIS asset. The parties agreed, among other things, to an overall CIS cost of $118.7 million (subject to later adjustments or true-up), including capital, interest during construction ("IDC") and procurement costs. This overall cost was to be recovered over the ten year service life of the new CIS asset. Under the terms of the 2007 Settlement Agreement, the amount included in opening rate base as of January 1, 2013 for the new CIS asset was to be its assumed 2012 closing net book value of approximately $71.4 million. That amount, which is based on the assumed CIS cost of $118.7 million, was subject to adjustment to reflect the actual costs of the new CIS asset.

The 2007 Settlement Agreement's $118.7 million assumed cost for the new CIS asset was based upon a number of things, including: (i) an estimated amount of $42 million for system integrator ("SI") contract costs, which was still in the midst of a direct competitive tender process; (ii) an amount of approximately $76.7 million for all other project costs, which Enbridge was to "manage and control during the CIS procurement and implementation process"; and (iii) an in-service date of January 1, 2009 (used for the estimation of IDC).[12]

The 2007 Settlement Agreement expressly provided for certain aspects of the CIS cost to be adjusted later, by setting a different rate base amount for the new CIS asset as of January 1, 2013, if there were variances from the costs assumed in the 2007 Settlement Agreement. In this regard, the 2007 Settlement Agreement provided that, subject to the restrictions on CIS costs set out therein, all prudently incurred and reasonable costs associated with the new CIS asset, including return and income taxes, should be recoverable in rates, during the 10-year economic life of the new CIS asset.[13]

As contemplated by the 2007 Settlement Agreement[14]*,* the stakeholder steering committee, with the added expertise of Five Point (who acted as expert advisors to the stakeholder steering committee) continued to be engaged with reviewing and monitoring the procurement and implementation of the new CIS asset after the time that the 2007 Settlement Agreement was approved. As of September 2009, the new CIS asset was successfully brought into service. Members of the stakeholder steering committee were provided with information about the implementation of the new CIS asset and the related costs. Five Point worked with the stakeholder steering committee, and Enbridge, throughout the CIS Replacement Project, and issued its Project Close-Out Report on October 29, 2009.[15] The Five Point Project Close-Out Report confirmed the success of the CIS implementation process. As stated by Five Point in its Project Close-Out Report: "The project launch was extremely smooth and can be considered as one of the most successful in the industry … The solution is of very high quality [and] is functioning as designed."[16]

At this time, the new CIS asset is in service, and past its warranty period (which expired in December 2009), and all of the associated capital costs are known. It is now clear that the actual costs of the new CIS asset are different from the assumed CIS cost of $118.7 million that was set out in the 2007 Settlement Agreement. Enbridge and members of the stakeholder steering committee agreed that the additional implementation costs associated with the new CIS asset are reasonable and prudently incurred. The additional costs, which are detailed at Ex. B-3-1[17] total

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[12] 2007 Settlement Agreement, at pp. 11-13, filed as I-1-33.

[13] 2007 Settlement Agreement, at p. 13, filed as I-1-33.

[14] 2007 Settlement Agreement, at p. 6, filed as I-1-33.

[15] A copy of Five Point's Project Close-Out Report is filed as Ex. B-3-2.

[16] Ex. B-3-2, Project Close-Out Report, at slide 3.

[17] At paras. 14 to 17.

approximately $8.5 million. In evidence at the Technical Conference, the Five Point witnesses confirmed that the implementation of the new CIS was successful at a cost that was reasonable and well within industry standards and expectations.[18]

The updated opening rate base value of $76.9 million for the new CIS asset as of January 1, 2013 is approximately $5.5 million higher than the $71.4 million assumed value in the Settlement Agreement. This approach means that approximately $3.0 million of the $8.5 million of additional SI and IDC costs incurred by Enbridge will not be included in the adjusted opening rate base, because that portion relates to amounts that would otherwise have been recovered during the term of the 2007 Template. In other words, Enbridge will not recover that portion of the additional CIS costs which would have been part of revenue requirement during the term of the 2007 Settlement Agreement. That is because the values in line 3 of the 2007 Template that relate to CIS revenue requirement for 2007 to 2012 are not subject to adjustment based upon increased costs. The only adjustment is to the updated rate base value at the end of the term of the 2007 Template, which is what is being addressed in this Settlement Agreement.

Having reached agreement on the opening rate base value for the new CIS asset as of January 1, 2013, Enbridge and members of the stakeholder steering committee then addressed the revenue requirement associated with that determination. Enbridge and members of the stakeholder steering committee agreed that the CIS revenue requirement calculations for 2013 to 2018 would use the same the parameters (including cost of capital) as were used for the calculation of CIS revenue requirement amounts in the 2007 Template. All parties agree that the use of these parameters for the calculation of the line 3 revenue requirement in the Updated 2013 Template (including, for example, the use of an ROE component of 8.39%, which is lower than the ROE that would result from the use of the Board's updated ROE formula) is not intended as a precedent for any future proceedings and is without prejudice to the right of any party to assert that a different approach should be used for the calculation of revenue requirement for capital assets in any future proceedings. To be clear, though, the use of these parameters will continue to apply for the calculation of the CIS revenue requirement in line 3, which is a component of the cost per Customer to be recovered by Enbridge for the years from 2013 to 2018.

Through Enbridge's Application and the settlement process, all parties have now agreed with Enbridge and the stakeholder steering committee that $76.9M is an appropriate opening rate base for the new CIS asset, as of January 1, 2013, and that the revenue requirement set out in line 3 of the Updated 2013 Template is appropriate. The total revenue requirement associated with the new CIS asset over the 2013 to 2018 period is $137M.[19]

In order to convert the amounts agreed upon to a cost per Customer, the annual revenue requirement amounts set out at line 3 were divided by the current forecast number of Customers for each year, as set out at line 17 of the Updated 2013 Template. Those annual costs per Customer for the new CIS asset range from $12.34 in 2013 to $8.93 in 2018.

[18] Transcript from August 17, 2011 Technical Conference, at pp. 10-12, 30, 34-40 and 42-47.

[19] The calculation of this revenue requirement amount is set out in more detail in Ex. B-3-4.

B. Accenture CCSA costs (line 10a of Updated 2013 Template)

All parties agree, on a cost per Customer basis, to the costs associated with the contracted CC services to be obtained by Enbridge through the revised and extended CCSA with Accenture over the 2013 to 2018 term. Based upon Enbridge's forecast of Customers for the 2013 to 2018 term, all parties agree that a total cost of $300.8M for those services is appropriate. That number, which is set out at line 10a of the Updated 2013 Template, has been converted into an annual cost per Customer amount for each year from 2013 to 2018. This amount does not include costs associated with Enbridge's large volume billing ("LVB") activities, which were previously provided by Accenture, but which have now been repatriated to Enbridge. Accordingly, the LVB costs that were included in line 10a of the 2013 Template attached to this Application (as Ex. A-2-2) have been moved to line 12 (Enbridge's backoffice CC costs) in the Updated 2013 Template. The context and basis for the agreement in respect of Accenture CCSA costs is set out in the following paragraphs.

Enbridge currently acquires the majority of its CC services from third party service providers, primarily Accenture. Accenture was chosen as a result of a RFP process run by Enbridge in 2007, which process was explained in the 2007 Settlement Agreement. The members of the stakeholder steering committee were involved in reviewing and commenting upon Enbridge's RFP process that resulted in the selection of Accenture for CC services.

The contracts under which these CC services are purchased (the current CCSA) will reach their normal expiry dates on March 31, 2012. As part of its acquisition of CC services beyond March 31, 2012, Enbridge will either have to execute an agreement with Accenture for the provision of the existing CC service arrangements for a period beyond the scheduled termination of those arrangements (because any transition will take place after that date), enter into service agreements with alternate service providers, repatriate these business functions or trigger extension agreements to extend the existing arrangements with Accenture.

In recognition of the long lead times required to establish CC services, and in recognition of the magnitude and scope of those CC services that Enbridge currently acquires from Accenture, Enbridge embarked upon an initiative in early 2010 to assess its current customer care delivery arrangements and formulate a strategy to meet its CC requirements beyond March 2012. As part of the service delivery review, Enbridge canvassed internal business stakeholders and undertook an external review of industry trends and best practices with respect to CC service delivery strategy. Through this process Enbridge gained information as to current trends in business process outsourcing in the North American utility sector. Additionally, Enbridge determined that EquaTerra Inc. ("EquaTerra") was best suited to assist the Company in a more detailed comparison of Enbridge's CC operations to current industry best practices. EquaTerra was engaged by Enbridge to review the current CCSA and provide perspectives on how Enbridge's outsourced CC services compared to current market standards in terms of cost, service levels and other contract terms. EquaTerra's report to Enbridge concluded that in general there are no major structural defects or omissions in the Enbridge / Accenture CCSA. EquaTerra also found that the current CCSA applies a price per customer model, which is a preferred market methodology for utilities and that comparative market analysis revealed that the Normalized Base Price lies within market comparable market ranges.

Enbridge formalized its CC strategy after receiving the EquaTerra Study. The resulting Enbridge CC strategy took into account the current positive experience with Accenture, the findings of EquaTerra and the notice requirements under the current CCSA, as well as the lead time required to conduct a market tender for the CC services procured under the CCSA and the time required to transition such services to a new vendor if required. A copy of the Enbridge CC Strategy, which appends the EquaTerra Study, is filed as Ex. B-4-3.

At or around that time, Enbridge involved the stakeholder steering committee, to make them aware of the ongoing process and to get their comments and suggestions. Five Point assisted the stakeholder steering committee in that process. The stakeholder steering committee agreed to review Enbridge's progress, and provide a stakeholder perspective on any decisions proposed by Enbridge. To assist in these activities, Enbridge and the members of the stakeholder steering committee agreed upon a Statement of Principles to guide their efforts. A copy of the Statement of Principles is filed as Ex. B-4-4.

Enbridge issued a sole source request for proposal to Accenture in July 2010 to provide the Company with a proposal to extend the CCSA beyond March 2012, addressing Enbridge's revised requirements as documented in its CC strategy (see Ex. B-4-3). In the event that Accenture's extension proposal was not acceptable, Enbridge's approach was to proceed with a full market RFP process in late 2010 (the option with the longest lead time and greatest expense), while assessing the option to repatriate. Enbridge's rationale to consider extension of the contract with ABSU as the primary option was based on two major factors: (i) the total cost associated with conducting a full–blown RFP is in the order of $5-$10 million, with no guarantees that the net cost resulting from the RFP would be lower; and (ii) if a new service provider was chosen transition costs were estimated to be on the order of $20 million and, there are operational risks in transitioning services to either another third party or to repatriate the services back to Enbridge.

As contemplated by the CC Strategy, from July through December 2010 Enbridge was engaged in negotiations with Accenture for the revision and extension of the CCSA. Ultimately, Enbridge and Accenture were able to agree upon a revised and extended CCSA that would run from January 1, 2011 to December 31, 2017, along with an Enbridge extension option for 2018 and 2019. Through the negotiation process, with substantial input from the stakeholder steering committee, Enbridge was able to reduce the total contract amount from Accenture's original $457M proposal to a final amount of $430M. The revised and extended CCSA that Enbridge negotiated adopts recommendations from EquaTerra about contractual terms and conditions, contains enhanced service levels (and adopts suggestions made by Five Points to achieve savings) and is priced at a competitive level. Essentially, the extended and updated CCSA provides for enhanced service levels at a per-customer price that is comparable (over a lengthy term) to current pricing. As a result of this successful outcome, the costs and risks of full market RFP were successfully avoided. The revised and extended CCSA that Enbridge has negotiated with Accenture will take effect as of April 1, 2012, as long as OEB approval of the cost consequences of that agreement has been obtained prior to that date.[20]

Review and comment on the terms, conditions and pricing of the revised and extended CCSA can be found in the Five Point report that is included as Ex. B-4-2, and in the evidence and

[20] However, as described above, Enbridge must have OEB approval by mid-September in order to avoid having to negotiate a short-term extension of the current CCSA.

undertaking responses from Five Point from the Technical Conference. As seen in those documents, Five Point endorsed the approach that Enbridge followed to negotiate a revised and extended CCSA, and found that the price was a reasonable one, in the circumstances and in comparison with market comparables. Five Point also explained how stakeholder involvement in the procurement process assisted in leading Enbridge to negotiate an overall contract value that was more than $27M less than Accenture's first offer. In its final report to the stakeholder steering committee, Five Point commented that:

- Enbridge's approach was "appropriately timed and logically sequenced" in terms of looking to negotiate with Accenture to extend the agreement before pursuing other options.[21]
- Enbridge was transparent and cooperative in dealings with Five Point.[22]
- Enbridge was successful in striking a contract extension with ABSU for almost the same price as the current CCSA agreement, but with many improvement items incorporated in the new contract.[23]
- The year-over-year increase in annual price through the course of the 7-year contract is within the market norms.[24]

The total cost associated with the revised and extended Accenture contact (the CCSA) is approximately $430M, from January 1, 2011 to December 31, 2017. For a number of reasons, that total cost does not align with the $300.8M amount included in the Updated 2013 Template at row 10a for Accenture CCSA costs. The first reason for the difference is that the Updated 2013 Template does not include costs for 2011 and 2012 under the revised and extended CCSA (since the costs for those years are included in the 2007 Template and already-approved smoothed revenue requirements for 2011 and 2012).[25] The second reason for the difference is that the 2013 Template includes costs for 2018, which are based on the extension option in the revised and extended CCSA (and which are not included in the $430M amount). The third reason for the difference is that the $430M amount includes costs associated with the provision of LVB services, which costs total $17.8M from 2013 to 2018. Given that the Company has now repatriated those services, the LVB costs that were included in line 10a of the 2013 Template attached to this Application (as Ex. A-2-2) have been moved to line 12 in the Updated 2013 Template. The final reason why the $430M total cost of the ABSU CCSA is different from the $300.8M amount in line 10a is that the total ABSU CCSA cost amount includes costs associated with open bill access services and agent billing and collection ("ABC") services which are not included in line 10a of the Updated 2013 Template. The responses to Ex. JTC1.14 and JTC1.5 set out the numbers associated with the derivation of the $300.8M amount included in row 10a of the Updated 2013 Template.

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[21] Ex. B-3-2, Project Close-Out Report, at slides 6 and 7.

[22] Ex. B-3-2, Project Close-Out Report, at slide 28.

[23] Ex. B-3-2, Project Close-Out Report, at slide 28.

[24] Ex. B-3-2, Project Close-Out Report, at slide 28.

[25] As the Company's CC costs for 2011 and 2012 are already addressed in the 2007 Settlement Agreement and the 2007 Template, Enbridge is not seeking any approval of the 2011 and 2012 costs associated with the revised and extended CCSA.

All parties agree that a total cost of $300.8M for the CC services to be obtained through the revised and extended CCSA with Accenture from 2013 to 2018 is appropriate. That number, which is set out at line 10a of the Updated 2013 Template, has been converted into an annual cost per Customer amount for each year from 2013 to 2018, using the Company's current forecast of Customers at line 17. Those annual costs per Customer range from $22.34 in 2013 to $24.13 in 2018.

C. All other CIS and CC costs in the Updated 2013 Template

All parties agree, on a cost per Customer basis, to the "other CIS and CC costs" (that is, all the costs in the Updated 2013 Template other than those set out in lines 3 and 10a) set out in the Updated 2013 Template. Based upon Enbridge's forecast of Customers for the 2013 to 2018 term, all parties agree that a total cost of $297.2M for the items set out in lines 4, 5, 6, 10b, 10c, 11 and 12[26] of the Updated 2013 Template is appropriate. That total cost amount, which is the sum of the annual amounts from lines 4, 5, 6, 10b, 10c, 11 and 12 of the Updated 2013 Template, has been converted into an annual cost per Customer amount for each year from 2013 to 2018. The context and basis for the agreement in respect of the "other CIS and CC costs" is set out in the following paragraphs.

As explained above, after Enbridge and the stakeholder steering committee agreed upon 2013 to 2018 costs for the new CIS (line 3) and the revised and extended CCSA with Accenture (line 10a), they turned their attention to Enbridge's other CIS and CC costs for that period. Those parties agreed that it made sense to look at and try to resolve those other costs at this time (rather than at the time of rebasing) for several reasons. First, this approach worked well in the 2007 Settlement Agreement – it has allowed both Enbridge and ratepayers to benefit from stable and pre-set revenue requirements for a large portion of the utility's costs. Second, this approach provides a more complete context to evaluate the impact of the forecast CIS and CCSA costs for 2013 to 2018, in conjunction with all related CIS and CC costs. Finally, this approach ensures that neither Enbridge nor ratepayers are later disadvantaged by having the related CIS and CC costs set at a different time from the CCSA and CIS asset costs.

Accordingly, Enbridge and members of the stakeholder steering committee agreed that it was appropriate to examine Enbridge's other forecast CIS and CC costs for the 2013 to 2018 period. This was done by expanding the 2007 Template that was attached to the 2007 Settlement Agreement to include therein the Company's CIS and CC costs for the 2013 to 2018 period, upon which Enbridge and the steering committee had agreed, along with Enbridge's forecasts of all of its other CIS and CC costs for that time frame.

Enbridge and members of the steering committee did not negotiate on these other CIS and CC costs, as they all wished to broaden their discussions to include all stakeholders. Accordingly, Enbridge proceeded with this Application in which it explained the nature and rationale for all such costs, and sought to negotiate an appropriate resolution with all stakeholders, for presentment to the Board.

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[26] This line includes costs associated with Enbridge's LVB activities, which were previously provided by Accenture, but which have now been repatriated to Enbridge.

Enbridge's evidence addresses the nature and amounts forecast for each of the lines in the 2013 Template that contain "other CIS and CC costs for 2013 to 2018. The line items at issue and the nature of the costs in each line are as follows[27]:

Line No.	Title	Description
4	New CIS Hosting and Support	Costs incurred to host and operate the new Enbridge CIS. Approximately 50% of these costs are for direct labour and the remaining 50% for amounts paid to external parties for equipment maintenance etc. These amounts do not include any associated overhead costs (HR, benefits, IT, facilities etc).
5	CIS Backoffice (EGD Staffing)	Costs incurred to perform application support for the new Enbridge CIS. Principally, these costs pertain to Enbridge direct labour. These amounts do not include any associated overhead costs (HR, benefits, IT, facilities etc).
6	SAP Licence Fees	Annual fees payable by Enbridge to SAP in respect of the SAP software licence required for the operation of the new Enbridge CIS.
10b	MET	Annual fees payable by Enbridge to MET in respect of meter reading services.
10c	Postage	Annual cost of Canada Post charges incurred by Enbridge for the delivery of monthly customer invoices and other customer correspondence.
11	Customer Care Licences	The annual cost for software licence for smaller software applications required.
12	Customer Care Backoffice (EGD staffing)	The annual cost incurred by Enbridge to manage and administer the Customer Care business function. This cost is primarily in respect of wages paid to personnel performing this function; and consulting resources to manage the Customer Care business. It also includes costs associated with the repatriated LVB CC function.

The 2013 Template included with the Application set out Enbridge's forecast costs in each of these lines from 2013 to 2018 (see Ex. A-2-2). Those forecast costs were developed by starting with actual 2010 costs which were then inflated using annual inflators that were deemed appropriate for each line. The inflators used were known third party amounts (as for MET and postage costs), CPI and wage inflation, as explained at Ex. I-1-2. Through the discovery process in this case, Enbridge provided additional information about the nature of the other CIS and CC costs and about the manner in which forecasts of those costs for future years were derived.

In order to achieve an overall settlement, all parties have agreed to treat Enbridge's other CIS and CC costs together for the purpose of determining appropriate amounts for 2013 to 2018. This means that the same inflator is to be applied to all costs, even if the underlying cost/inflation drivers are different. Without prejudice to the position that any party might take in future Enbridge proceedings, all parties believe that the use of this approach in this case to address Enbridge's

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[27] See Ex. I-2-1.

"other CIS and CC costs" for a six year term is appropriately consistent with IRM-type ratemaking approaches.

Using this approach, and in order to achieve an overall settlement, all parties have agreed that it is appropriate to express Enbridge's forecast "other CIS and CC costs" (lines 4, 5, 6, 10b, 10c, 11 and 12) for 2013 (as set out in the 2013 Template filed as Ex. A-2-2) on a cost per Customer basis for 2013. On a cost per Customer basis, Enbridge's forecast of these costs for 2013 (taken from Ex. A-2-2) is $23.07. For the purposes of reaching an overall settlement, and in order to set a base cost per Customer for 2013, all parties agree that Enbridge's forecast cost per Customer for the "other CIS and CC costs" will be reduced by $2.00. The result is a 2013 cost per Customer of $21.07 for the "other CIS and CC costs" set out in the Updated 2013 Template, based upon Enbridge's forecast number of Customers. That cost per Customer is then inflated each year from 2014 to 2018, as described below, in order to determine future year costs per Customer.

D. Total cost per Customer in the Updated 2013 Template

Taking all of the above together, the parties have agreed on a total 2013 cost per Customer of $55.75 for all 2013 costs in the Updated 2013 Template derived as follows:

		2013
CIS Line 3 only cost/Customer	$	12.34
Line 10a only cost/Customer	$	22.34
All other cost/Customer	$	21.07
Line 17a Total cost/Customer	**$**	**55.75**

This cost per Customer represents Enbridge's base costs for the items set out in the Updated 2013 Template for the 2013 to 2018 period. That base cost per Customer is approximately 3.5% less than Enbridge's forecast costs as set out in this Application (as seen in the 2013 Template filed as Ex. A-2-2).

In order to create future year costs per Customer, all parties agree that the 2013 base cost per Customer will be inflated by 0.6% for each year from 2014 to 2018. All parties agree that the inflator used for the purpose of creating costs per Customer for 2014 to 2018 is a compromise number that creates reasonable results in this case, but also agree that it will not be relied upon as a precedent or indicator of an appropriate inflator of costs or rates in any other Enbridge proceeding. The evidence filed in this proceeding establishes that the inflation factors that might be relevant, whether they are the factors used in Enbridge's current IRM mechanism or are CPI or wage inflation, are higher than the 0.6% inflator used here.

The result of the approach described above is that the agreed-upon cost per Customer for all of Enbridge's CIS and CC costs set out in the Updated 2013 Template ranges from $55.75 in 2013 to $57.42 in 2018. These amounts include costs per Customer for the new CIS asset based on the amounts in line 3 and costs per Customer for the revised and extended CCSA with Accenture based on the amounts set out in line 10a. Implicit in that approach is a cost per Customer for other CIS and CC costs (exclusive of lines 3 and 10a) that ranges from $21.07 in 2013 to $24.36

in 2018. The total annual cost per Customer is set out in the Updated 2013 Template, in line 17a, which is titled "Total cost/customer".

Over the term of the 2013 Template, the results of the approach used for the purposes of reaching an overall settlement of all costs set out in the Updated 2013 Template are as follows:

	2013	2014	2015	2016	2017	2018
CIS Line 3 only cost/Customer	$ 12.34	$ 11.61	$ 10.89	$ 10.21	$ 9.56	$ 8.93
Line 10a only cost/Customer	$ 22.34	$ 22.74	$ 23.04	$ 23.22	$ 23.40	$ 24.13
All other cost/Customer	$ 21.07	$ 21.74	$ 22.49	$ 23.32	$ 24.12	$ 24.36
Total cost/Customer	**$ 55.75**	**$ 56.08**	**$ 56.41**	**$ 56.74**	**$ 57.08**	**$ 57.42**

For the purposes of creating the Updated 2013 Template, Enbridge has included the agreed-upon values in lines 3 and 10a. The values in the lines that comprise Enbridge's "other CIS and CC costs" are determined by: (i) multiplying the agreed-upon cost per Customer for the relevant year by the forecast number of Customers for that year to get a total cost for the year; (ii) subtracting the amounts in lines 3 and 10a for that year; (iii) allocating the remaining amount among lines 4, 5, 6, 10b, 10c, 11 and 12 in a manner that replicates the originally-filed 2013 Template, so that proportionate reductions are applied to each line. All parties agree that the individual cost amounts set out in the individual lines of the Updated 2013 Template are illustrative only. As set out below, it is the overall cost per Customer on an annual basis that will be used to determine annual costs and revenue requirement. That is because the number of Customers each year is likely to vary from the forecast set out in line 17 of the Updated 2013 Template.

E. Annual revenue requirement

All parties agree that it is reasonable and appropriate for Enbridge to recover the agreed-upon total cost per Customer in each year of this agreement (from 2013 to 2018). At a high level, this is to be done by multiplying the agreed cost per Customer for any particular year by the most current forecast number of Customers for that year, to arrive at an overall revenue requirement for that year for all costs set out in the Updated 2013 Template. All parties agree that the annual revenue requirement that is determined through the process described herein will be recovered as a pass-through cost in Enbridge's rates (whether those rates are set through an IRM mechanism or cost of service). That is the same approach as was adopted in the 2007 Settlement Agreement, and Enbridge's current IRM mechanism, whereby the agreed-upon annual CIS and CC revenue requirement set through the 2007 Settlement Agreement has been treated as a Y-factor in Enbridge's annual rate adjustment applications.

All parties agree that while the cost per Customer set out in this Settlement Agreement (and in line 17a of the Updated 2013 Template) is fixed and will not change over time, the Customer forecast that is used each year to set the revenue requirement will be updated as part of the rate-setting process for the relevant year. Therefore, in order to set an annual revenue requirement for a particular year, it will be necessary to determine the appropriate number of Customers for that year, using the definition of "Customer" set out below. That will be done as part of the rate-setting process for each year, regardless of the ratemaking regime that applies to Enbridge in any year. Enbridge's Customer forecast set out in line 17 of the Updated 2013 Template was prepared using the definition of "Customer" in the Accenture CCSA, since that definition is what is used to determine Accenture's costs. As described above, it is the line 17 forecast of Customers that was used to determine forecast costs in the 2013 Template (that was also the case in respect of the 2007 Template). Therefore, in order to be consistent, the annual forecast of Customer numbers that will be used to determine annual CIS and CC revenue requirements in each year from 2013 to 2018 will also apply the definition of Customer from the Accenture CCSA.[28] That definition provides that "the term Customer shall mean: a person actively receiving gas distribution and/or natural gas commodity service from EGD; or a person that has had gas distribution and/or natural gas commodity service from EGD terminated for non-payment, which account is subject to Collection Services under this Agreement.". In other words, the annual forecast of Customers will include both active and locked customers.

It should be noted that the approach to determining annual CIS and CC revenue requirement for the years from 2013 to 2018 is different from the approach adopted in the 2007 Settlement Agreement. The difference arises from the fact that the settlement in this case is premised on a fixed annual cost per Customer to be recovered, rather than upon a fixed annual revenue requirement to be recovered. What that means is that while the cost per Customer to be recovered each year is being set through this Settlement Agreement, the annual revenue requirement to be recovered under the terms of this Settlement Agreement will not be set until the rate-setting proceeding for each relevant year, when the forecast number of Customers for that year is known.

F. Smoothing

The annual revenue requirement determination process set out in the paragraphs above would apply if the cost per Customer agreed upon was simply applied each year without modification. Intervenors have indentified, however, that this approach would result in a 2013 increase (versus 2012) in revenue requirement (and cost per Customer) that is relatively higher than ratepayers would prefer. Therefore, for the purposes of settlement, the parties have agreed upon a different pattern of recovery which lessens the impact of increased revenue requirement in 2013 and provides rate stability over the 2013 to 2018 time period. This is effected by creating a lower cost per Customer for 2013 and then increasing that cost per Customer over the remainder of the term in a manner that will allow Enbridge the opportunity to recover the full agreed-upon revenue requirement of $735M (assuming that the Customer forecast in line 17 is accurate).

The total cost per Customer (without smoothing) for 2013 agreed upon in the Updated 2013 Template is $55.75. While that amount is lower than Enbridge's forecast 2012 cost per Customer of $57.37[29], it is higher than the smoothed cost per Customer of $49.06 that will be collected by Enbridge in rates for 2012, using the "smoothed" revenue requirement set out at line 23 of the 2007 Template and Enbridge's current forecast of customers for 2012.[30] In order to temper the

[28] Found in the Overview section of Schedule 3.1 to the CCSA ("Service Fees") – see Ex. I-1-12.

[29] As set out in the version of the 2013 Template filed as Ex. B-5-2.

[30] To be clear, this 2012 cost per Customer was calculated as follows: the 2012 "smoothed" revenue requirement set out in line 23 of the 2007 Template (which number is also set out in the Updated 2013 Template) was divided by Enbridge's current forecast of Customers for 2012, which is set out at line 17 of Ex. B-5-2. .

cost per Customer (and corresponding rate) increase from 2012 to 2013[31], all parties have agreed to reduce the 2013 cost per Customer from $55.75 to $53.50. That represents a 9.1% increase from the forecast 2012 cost per Customer ($49.06) that will be collected in rates for 2012. Then, in order to ensure that Enbridge can recover the total agreed-upon revenue requirement of $735M (based on current Customer forecasts), the smoothed 2013 cost per Customer of $53.50 will be increased by 2.2% per year, ultimately leading to a 2018 cost per Customer to be recovered in rates of $59.65. The result is that the cost per Customer to be recovered in rates for 2018 will be higher than Enbridge's actual agreed upon cost per Customer of $57.42 per year. The fact that Enbridge's recovery per Customer will be higher than its costs over the later years of the Updated 2013 Template will offset the fact that Enbridge will recover an amount less than its costs in the early years.

The cost per Customer that Enbridge will recover in revenue requirement is set out at line 24 of the Updated 2013 Template. For convenience, it is also reproduced below:

	2013	*2014*	*2015*	*2016*	*2017*	*2018*
Line 24 Revenue Requirement/Customer	**$ 53.50**	**$ 54.68**	**$ 55.88**	**$ 57.11**	**$ 58.36**	**$ 59.65**

As explained above, as part of the ratesetting process for each year from 2013 to 2018, the annual cost per Customer at line 24 will be multiplied by the updated Customer forecast for that year (using the definition of "Customer" from the Accenture CCSA, as set out above) to derive the total revenue requirement for all services included in the Updated 2013 Template for that year. The total revenue requirement that is determined will be recovered as a pass-through cost in Enbridge's rates (whether those rates are set through an IRM mechanism or cost of service).

G. Deferral account

The smoothing of the CIS and CC revenue requirement will result in Enbridge recovering less than its allowed costs over the early years of the Updated 2013 Template. Parties agree that Enbridge should be allowed to create a deferral account to track its forecast recovery of revenue requirement for the CIS and CC services set out in the Updated 2013 Template versus its forecast allowed costs for those services, and to charge interest on that account. Parties agree that, in principle, this is similar to the approach taken for electricity distributors, where rate mitigation is accomplished by spreading anticipated rate increases over several years while tracking annual under-recovery and associated interest. Since smoothing is a type of rate mitigation, all parties believe it is appropriate to use a similar approach.

The details of the agreed-upon deferral account approach are as follows.

- Enbridge will create a rate smoothing deferral account for each year from 2013 to 2018 which will capture the difference between Enbridge's forecast CIS and CC costs each year versus the amount to be collected in revenue requirement. The costs to be used in this regard will be

[31] The primary reason for this increase in smoothed cost per customer, as explained above in the "Background" section, is that ratepayers will receive the full CCA (depreciation) benefit from the new CIS during the term of the 2007 Template and none of that benefit will be available to offset revenue requirement as of 2013. This outcome was anticipated and understood by all parties at the time of the 2007 Settlement Agreement.

the "Total cost/customer" amount set out for each year in line 17a of the Updated 2013 Template, multiplied by the forecast number of Customers (using the definition from the CCSA) for that year. The revenue requirement amount to be used will be the "smoothed" cost per Customer set out for each year in line 24 of the Updated 2013 Template, multiplied by the forecast number of Customers (using the definition from the CCSA) for that year. For simplicity, Enbridge will calculate the amount to be credited or debited to the deferral account each year by multiplying the difference in cost per Customer and smoothed cost per Customer, times the updated Customer forecast for the year. For example, in 2013 the debit to the deferral account will be ($55.75 less $53.50) times the updated Customer forecast. In the early years of the 2013 to 2018 term, the balance in the rate smoothing deferral account will grow (because Enbridge's cost per Customer will be higher than the smoothed cost per Customer being collected), and then in the later years the balance will decline (because Enbridge's cost per Customer will be lower than the smoothed cost per Customer being collected).

- Enbridge will be entitled to collect interest on balances in the rate smoothing deferral account (at a fixed annual rate of 1.47%, which is the current Board-approved rate, and will not change during the period the deferral account continues). Interest amounts will be cleared annually to customers, at the same time as Enbridge's other deferral and variance accounts are cleared.

- The principal balance in the rate smoothing deferral account will not be cleared during the 2013 to 2018 term. Instead, the principal balance will build up during the years from 2013 to 2015 (when Enbridge's cost per Customer will be higher than the smoothed cost per Customer) and then the balance will be drawn down over the years from 2016 to 2018 (when Enbridge's cost per Customer will be lower than the smoothed cost per Customer). In the event that there is any balance remaining in the rate smoothing deferral account at the end of 2018, that balance (whether it is positive or negative) will be cleared to customers along with the clearance of other 2018 deferral and variance accounts.

H. Bill impacts from Settlement Agreement

For the purposes of this proceeding, all parties agree that it is not necessary to address any issues about the allocation of the costs set out in the Updated 2013 Template to rate classes on the basis of customer numbers. The parties agree that the appropriateness of this or any other cost allocation between rate classes is most appropriately addressed as part of Enbridge's rate applications for 2013 and beyond. For the purposes of determining bill impacts from this Settlement Agreement, all parties agree that it is appropriate to use the cost allocation methodology that applies to the 2007 Template, which allocates the "smoothed" CIS and CC revenue requirement to rate classes on the basis of Customer numbers. That agreement is without prejudice to the right of any party to address the issue of rate class allocation of these costs as part of Enbridge's rate applications for 2013 and beyond.

All parties agree that the bill impacts arising from the Settlement Agreement are reasonable and appropriate.

On an absolute basis, based on Enbridge's current forecast number of Customers for 2012 and 2013[32], the increase on customer bills arising from this Settlement Agreement will be $4.44 per customer from 2012 to 2013 (equal to a 9.1% year-over-year change in the customer care component of customer bills), and then approximately $1.20 per year (2.2%) for each year from 2014 to 2018.[33]

In terms of overall bill impact, the increase from 2012 to 2013 is equal to approximately 0.5% for a typical sales customer, and approximately 0.8% for a typical T-service customer. Then, the average bill impact for each year from 2014 to 2018 is equal to approximately 0.1% for a typical sales customer, and approximately 0.2% for a typical T-service customer. For ease of reference, the bill impacts arising from the use of the "smoothed" cost per Customer agreed upon in this Settlement Agreement are set out in the table below.

	2012	2013	2014	2015	2016	2017	2018
Smoothed cost/Customer - line 24	$ 49.06	$ 53.50	$ 54.68	$ 55.88	$ 57.11	$ 58.36	$ 59.65
Year over year % increase		9.1%	2.2%	2.2%	2.2%	2.2%	2.2%
Sales customer bill impact		0.5%	0.1%	0.1%	0.1%	0.1%	0.1%
T-Service customer bill impact		0.8%	0.2%	0.2%	0.2%	0.2%	0.2%

I. Other items

One of the Board's issues (Issue 19) asks whether any of the costs included in the 2013 Template should be considered to be "Non-Utility Costs". All parties agree that this proceeding is not the appropriate time for considering that question, as the scope of the Company's activities for the 2013 to 2018 period, including open billing activities, is not currently settled. Instead, the issue of how any costs included within the Updated 2013 Template that relate to activities such as open bill access and agent billing and collection should be treated is appropriately raised in Enbridge's rate applications for 2013 and beyond. Therefore, all parties agree that the settlement of an appropriate cost per Customer for all CIS and CC activities set out in the Updated 2013 Template is without prejudice to the position that any party may take in Enbridge's rate applications for relevant years as to how some of those costs should be eliminated or allocated in respect of non-utility activities and open bill access.

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[32] Enbridge's current Customer forecast numbers for 2012 are set out in the version of the 2013 Template filed as Ex. B-5-2. The Updated 2013 Template includes Enbridge's current Customer forecast for 2013 to 2018, as had been set out in the 2013 Template filed as Ex. A-2-2.

[33] It should be noted that the actual per customer bill impact for Enbridge's customers will likely be slightly different from what is shown in this paragraph. That difference arises from the fact that the absolute amount of bill increase and percentage increase for each customer as set out above is calculated based upon Enbridge's forecast number of Customers, using the definition of "Customer" from the ABSU CCSA. The fact is, though, that the number of billed customers will be slightly lower, because the term "Customer" includes locked customers (averaging in the range of 20,000 customers) who do not receive monthly bills. Therefore, to calculate a more precise bill impact per customer, one would have to use a forecast number of billed customers for 2012 and a similar forecast for 2013. Given that those forecasts are not part of the evidence in this proceeding, this calculation has not been included. All parties expect, though, that the result would not be materially different from the impacts described in this section of the Settlement Agreement.

All parties also agree that in the event that exogenous factors such as new legislative or regulatory requirements, that are currently unknown and that are beyond the Company's control, are imposed on the Company, in the period between 2013 and 2018, and those requirements materially change the level of Enbridge's overall costs from those that are set out in the Updated 2013 Template, then any of the parties shall be entitled to make application to the Board for adjustments to rates or revenue requirement as appropriate. The materiality threshold that applies to this aspect of the Settlement Agreement will be the same as exists in any Z-factor or similar provision that is included within the ratemaking regime that applies to Enbridge during any particular year between 2013 and 2018. The parties acknowledge that the individual lines in the Updated 2013 Template (other than lines 3 and 10a) are illustrative only, and therefore do not form an appropriate baseline for determination of whether the Z-factor materiality threshold is met. In considering whether a Z-factor materiality threshold is met for customer care costs, it is agreed that two tests must be met. First, the difference between Enbridge's forecast total costs for a year under this Settlement Agreement (calculated by multiplying the agreed cost per Customer for that year in line 17a by the forecast number of Customers for that year) and Enbridge's actual or updated forecast costs for that year for the items set out in the Updated 2013 Template must exceed the threshold. Second, the party claiming Z-factor treatment must establish a specific exogenous event, not taken into account in developing the Template totals, that has caused a net new cost exceeding the threshold. By way of example, if postage rates are increased in a future year, and as a result the postage cost for the year exceeds the amount in the Template by more than the threshold, that will not be sufficient for Z-factor treatment, because it is known that postage rates will change over the 2013 to 2018 term. On the other hand, and by way of further example, if the Company is ordered, by the Board or otherwise, to accept credit card payments for its bills, and the credit card fees imposed on Enbridge exceed the threshold, that could qualify for Z-factor treatment if all other factors are met. (The foregoing examples are intended to assist interpretation of this provision only.) In assessing whether an individual exogenous event caused costs exceeding the threshold, all cost impacts of that event must be included, favourable and unfavourable. The parties agree that the rights conferred in this paragraph will be no greater than any rights to revisit any issue based on changes in legislative or regulatory requirements that are established as part of the regulatory rules (including any applicable IRM mechanism) that apply to the Company in any given year.

The parties agree to continue the provision in the 2007 Settlement Agreement dealing with future revenue generating opportunities from the new CIS, as follows:

The Company agrees to use its best efforts to identify and take advantage of opportunities to use the new CIS asset to provide CIS services to third party organizations to generate additional revenue opportunities, and that the gains from any such opportunities shall be shared with ratepayers in a manner to be agreed upon. A consultative group, including intervenors, may be convened to consider how such opportunities should be addressed. The parties agree that, in the event that the sharing of such gains cannot be agreed upon by the parties, then they will put the issue of the appropriate gainsharing to be used to the Board. The parties agree that any gains to be shared with ratepayers would be cleared to ratepayers by way of an annual adjustment to delivery rates. Billing services on the Enbridge Gas Distribution bill are covered by a separate process related to open bill access, and are not included in or affected by the provisions set out above.

EVIDENTIARY BASIS FOR THE SETTLEMENT

All parties agree that there is a sufficient evidentiary basis to support the settlement detailed herein. That evidentiary record was built up in a number of ways, including through the prefiled evidence (which includes documentation from the consultative process that led up to the Application) and through a full discovery process, which included written interrogatories, an oral technical conference where representatives of Enbridge and Five Point gave evidence and answered questions, and follow-up questions emanating from the technical conference.

The evidence supporting the settlement is listed in the next sections of this Settlement Agreement, on an issue by issue basis. As can be seen, there are multiple pieces of evidence which are relevant to each of the issues set out in the Board's Issues List.

At a high level, the evidence addresses categories of issues, as follows.

First, Enbridge has provided evidence describing the background to this Application, and the reasons why it is appropriate for the Board to consider an extension of the 2007 Template to address CIS and CC costs for the 2013 to 2018 period. That evidence describes how the Company made decisions to acquire a new CIS and enter into a contract with Accenture for CC services. It also describes the manner in which Enbridge worked with the intervenor steering committee to get agreement upon the process and costs associated with the new CIS and CC contract, and the role played by the intervenor expert (Five Point) in that process. The evidence addresses how the 2007 Template was developed, and then approved and endorsed by the Board. Finally, the evidence sets out how the approach used in the 2007 Template has worked well since that time.

Second, there is a large amount of evidence about the process undertaken by Enbridge to determine how to obtain continued CC services after the current CCSA with Accenture. That evidence describes Enbridge's internal process to identify options for how to proceed, and the decisions taken in that regard. It also describes the participation of the stakeholder steering committee and Five Point in reviewing the Company's actions and making recommendations on how to proceed. The evidence includes explanation of why it was appropriate for the Company to extend and update its CCSA with Accenture, rather than proceeding to an RFP process, along with the endorsement of Five Point to proceeding in that manner. The evidence also includes benchmarking information from EquaTerra and Five Point supporting the reasonableness of the costs set out in the revised and extended Accenture CCSA. Finally, the evidence from both Enbridge and Five Point describes the benefits of the extended and updated CCSA. This topic was the subject of much of the testimony of Five Point and Enbridge at the Technical Conference, and was also the subject of a number of interrogatories and undertakings. All of this evidence serves to support the values set out in line 10a of the 2013 Template.

Third, the evidence sets out the manner in which the new CIS revenue requirement set out in line 3 of the 2013 Template was derived. That evidence describes the provisions of the 2007 Settlement Agreement addressing the anticipated costs of the new CIS and the manner in which those costs would be reflected and potentially adjusted in an opening rate base value at December 31, 2012 (which is the end date of the 2007 Template). The evidence also describes the successful implementation of the new CIS, and the final costs related to that asset. The role of the stakeholder steering committee and Five Point in reviewing and endorsing the implementation of the new CIS and the associated costs is set out in the evidence and in the Technical Conference testimony of Enbridge and Five Point. In that regard, the evidence describes how the updated opening rate base value of $76.9 million for the new CIS was derived and then converted into annual revenue requirement amounts for 2013 to 2018 using the same parameters as employed in the 2007 Template. Finally, the evidence sets out the endorsement of the stakeholder steering committee to the values set out in line 3 of the 2013 Template.

Fourth, the prefiled evidence addresses Enbridge's forecast other CIS and CC costs for 2013 to 2018, as set out in the balance of the 2013 Template. The evidence describes the nature of each of those sets of costs. The evidence also sets out how those forecasts were created, using current costs as a base and then adjusting those costs based upon inflation or contract/third party costs. Many of the interrogatories answered by the Company, as well as the evidence at the Technical Conference and resulting undertakings provide further detail about these costs. As explained herein, the Company's forecast of costs was used as the base from which adjustments were made in order to arrive at a 2013 cost per Customer for other CIS and CC costs.

Fifth, there is discussion in the evidence and in this Settlement Agreement about the financial impact of this settlement on ratepayers. The prefiled evidence explains the customer impact of the proposed 2013 Template, which included an overall revenue requirement amount of $758M. As explained herein, parties have agreed that (based on Enbridge's current Customer forecast), the appropriate revenue requirement to be recovered is $735M. This Settlement Agreement contains details about the total $735M amount of the CC and CIS revenue requirement was derived, and about how that revenue requirement has been smoothed to allow for annual revenue requirements that temper rate volatility. In addition, information is provided about the expected annual rate impact of this Settlement Agreement on a typical Enbridge customer.

DIFFERENCES FROM THE 2007 SETTLEMENT AGREEMENT

The parties have sought to follow the principles established in the 2007 Settlement Agreement and the 2007 Template, including the comprehensiveness of the cost analysis, and the goal of smoothing rate impacts. However, this Agreement and the Updated 2013 Template have certain material differences from the 2007 result, the most important of which are as follows:

- At the time of the 2007 Settlement Agreement, certain of the costs expected to be incurred were not known, including some of the CIS capital costs, and some of the CCSA costs. The 2007 Settlement Agreement contains extensive provisions relating to the true-up of forecast costs to actuals. This Agreement does not contain any true-up provisions, because the costs can be forecast with reasonable accuracy today.

- The 2007 Template resulted in agreement on annual revenue requirement totals, and smoothing on that same basis. This Agreement has added the factor of customer numbers, so that the revenue requirement agreed is per Customer, as is the smoothing method. This makes the smoothing more effective, and reflects the reality that a substantial portion of Enbridge's CC costs vary by number of Customers.

- The 2007 Template had to deal potentially with the costs of transitioning from one service provider to another. In this Agreement, it is known that the incumbent will be retained.

- The 2007 Template was timed to coincide with an Enbridge cost of service application serving as the base year for a multi-year IRM. The timing of this Agreement is driven by the desire of all parties to complete a favourable new CCSA agreement, which must be done prior to the next Enbridge rebasing application.

- The smoothing escalator in the 2007 Template was approximately 1.8% per year. The smoothing escalator in this Agreement is 2.2% per year, based on a cost escalator of 0.6% per year and an adjustment to reduce the 2013 impact on a per Customer basis from a 17.7% increase to 9.1% increase. The net result is a lower level of net cost escalation, coupled with a planned increase in overall service levels.

RESPONSE TO EACH ISSUE

Based upon the Terms of Settlement described above, and based upon the evidence filed in this proceeding, the following represents the response of all parties to each of the issues set out in the Board's Issues List.

1. Are the amounts proposed in the 2013 Template (Line 3) and identified as "New CIS Capital Cost @ Board Approved 36% Equity" appropriate for recovery?

As discussed above in the "Terms of Settlement" section (see pages 12 to 14), for the purposes of determining an annual cost per Customer for CIS and CC services set out in the Updated 2013 Template, all parties agree that the amounts proposed in Line 3 of the Updated 2013 Template for the revenue requirement for the new CIS Asset from 2013 to 2018 are appropriate. Those revenue requirement amounts are based upon an opening rate base value of $76.9M for the new CIS asset as of January 1, 2013.

The amounts in line 3 are calculated by using all of the same parameters (including cost of capital) for the calculation of resulting revenue requirement of the new CIS as were used in the calculation of the values in line 3 of the 2007 Template. All parties agree that the use of these parameters for the calculation of the line 3 revenue requirement in the Updated 2013 Template (including, for example, the 8.39% ROE value that is being used) is not intended as a precedent for any future proceedings and is without prejudice to the right of any party to assert that a different approach should be used for the calculation of revenue requirement for capital assets in any future proceedings.

As part of the agreement in respect of the recovery of costs associated with its new CIS, the parties agree that it is assumed that Enbridge will not replace or undertake major revisions to the new CIS prior to 2019. Enbridge agrees that if it seeks to close to rate base any CIS capital costs relating to this new CIS or a replacement CIS exceeding on a cumulative basis $50 million between January 1, 2013 and December 31, 2018, then Enbridge will make specific application for Board approval for such action. All parties are free to take whatever positions they consider appropriate on that application. Any such request by Enbridge shall, however, start from the assumption that the appropriate rate consequences (including depreciation, return, taxes, etc.)

are those that most closely track the rate consequences that would occur if the new capital assets were purchased, developed or built, and closed to rate base, in 2019.

Evidence: The evidence in relation to this issue includes the following:

A-2-2	2013 Template
B-2-2	Overview of Relief Sought
B-3-1	CIS Costs
B-3-2	Five Point's CIS Project Close-Out Report
B-3-4	Revenue Requirement Impact of New CIS Opening Rate Base Value
B-5-1	Explanatory Notes re. 2013 Template
I-1-1	Plain language description of each line item in the 2013 Template
I-1-2	Variance analysis for each line item in the 2013 Template
I-1-3	Variance analysis between forecast and actual values in 2007 Template
I-1-4	Variance analysis for 2013 new CIS opening rate base value
I-1-10	Rationale for the CIS cost recovery over two six-year spans
I-1-33	Copy of 2007 Settlement Agreement
I-2-2	Explanation of CIS costs in 2013 Template
I-2-5	Explanation of how costs in 2013 Template were inflated
Tech Conf	Evidence of Five Point at TC, pp. 10-12, 30, 34-40 and 42-47
Tech Conf	Evidence of Enbridge at TC, pp. 60-62, 84-86, 92-98, 99-101 and 122-123
JTC1.2	Five Point slide deck re. CIS implementation project costs
JTC1.3	Annual cost per customer for CIS services up to 2018

2. Are the amounts proposed in the 2013 Template (Line 4) and identified as "New CIS Hosting and Support" appropriate for recovery?

All parties agree that the costs on this line should be aggregated with all other lines (excluding lines 3 and 10a), and forecast on the basis of the per Customer amount and formula described on pages 20 to 22 above. The costs for this line as set in the 2013 Template are for illustrative purposes only, and are not separately validated in isolation from the totals.

Evidence: The evidence in relation to this issue includes the following:

A-2-2	2013 Template
B-2-2	Overview of Relief Sought
B-3-1	CIS Costs
B-5-1	Explanatory Notes re. 2013 Template
B-5-2	Version of 2013 Template Containing Actual/Forecast 2007 to 2012 Costs
I-1-1	Plain language description of each line item in the 2013 Template
I-1-2	Variance analysis for each line item in the 2013 Template
I-1-3	Variance analysis between forecast and actual values in 2007 Template
I-1-11	Explanation of how contract costs other than the new ABSU CCSA costs are determined during term of 2013 Template (given that some do not have 6 year terms)
I-1-23	Explanation of which items in the 2013 Template contain Enbridge's in-house costs
I-2-2	Explanation of CIS costs in 2013 Template
I-2-5	Explanation of how costs in 2013 Template were inflated
Tech Conf	Evidence of Enbridge at TC, pp. 81-83, 101-105 and 124-125
JTC1.3	Annual cost per customer for CIS services up to 2018
JTC 1.6	Updated annual costs for column E (2011 costs) of the 2013 Template (B-5-2)
JTC1.8	Breakout of costs in row 4 of the 2013 Template for 2010 to 2012

3. Are the amounts proposed in the 2013 Template (Line 5) and identified as "CIS Backoffice (EGD Staffing)" appropriate for recovery?

All parties agree that the costs on this line should be aggregated with all other lines (excluding lines 3 and 10a), and forecast on the basis of the per Customer amount and formula described on pages 20 to 22 above. The costs for this line as set in the 2013 Template are for illustrative purposes only, and are not separately validated in isolation from the totals.

Evidence: The evidence in relation to this issue includes the following:

A-2-2	2013 Template
B-2-2	Overview of Relief Sought
B-3-1	CIS Costs
B-5-1	Explanatory Notes re. 2013 Template
I-1-1	Plain language description of each line item in the 2013 Template
I-1-2	Variance analysis for each line item in the 2013 Template
I-1-3	Variance analysis between forecast and actual values in 2007 Template
I-1-23	Explanation of which items in the 2013 Template contain Enbridge's in-house costs
I-2-2	Explanation of CIS costs in 2013 Template
I-2-5	Explanation of how costs in 2013 Template were inflated
Tech Conf	Evidence of Enbridge at TC, pp. 128-129
JTC1.3	Annual cost per customer for CIS services up to 2018
JTC 1.6	Updated annual costs for column E (2011 costs) of the 2013 Template (B-5-2)

4. Are the amounts proposed in the 2013 Template (Line 6) and identified as "SAP Licence Fees" appropriate for recovery?

All parties agree that the costs on this line should be aggregated with all other lines (excluding lines 3 and 10a), and forecast on the basis of the per Customer amount and formula described on pages 20 to 22 above. The costs for this line as set in the 2013 Template are for illustrative purposes only, and are not separately validated in isolation from the totals.

Evidence: The evidence in relation to this issue includes the following:

A-2-2	2013 Template
B-2-2	Overview of Relief Sought
B-3-1	CIS Costs
B-5-1	Explanatory Notes re. 2013 Template
B-5-2	Version of 2013 Template Containing Actual/Forecast 2007 to 2012 Costs
I-1-1	Plain language description of each line item in the 2013 Template
I-1-2	Variance analysis for each line item in the 2013 Template
I-1-3	Variance analysis between forecast and actual values in 2007 Template
I-1-11	Explanation of how contract costs other than the new ABSU CCSA costs are determined during term of 2013 Template (given that some do not have 6 year terms)
I-2-2	Explanation of CIS costs in 2013 Template
I-2-5	Explanation of how costs in 2013 Template were inflated
JTC1.3	Annual cost per customer for CIS services up to 2018
JTC 1.6	Updated annual costs for column E (2011 costs) of the 2013 Template (B-5-2)

5. Are the amounts proposed in the 2013 Template (Line 10) and identified as "New Service Provider Contract Cost" appropriate for recovery?

All parties agree that the costs on this line (except those that relate to line 10a) should be aggregated with all other lines (excluding lines 3 and 10a), and forecast on the basis of the per Customer amount and formula described on pages 20 to 22 above. The costs for this line as set in the 2013 Template are for illustrative purposes only, and are not separately validated in isolation from the totals. All parties agree that the costs on line 10a are a reasonable forecast, measured on a per Customer basis, of the costs payable for regulated activities under the CCSA.

Evidence: The evidence in relation to this issue includes the following:

A-2-2	2013 Template
B-2-2	Overview of Relief Sought
B-4-1	Customer Care Costs
B-4-2	Five Point's Customer Care Consultative Report
B-4-3	Enbridge's Customer Care Strategy Document
B-4-4	Stakeholder Steering Committee Statement of Principles
B-5-1	Explanatory Notes re. 2013 Template
B-5-2	Version of 2013 Template Containing Actual/Forecast 2007 to 2012 Costs
I-1-1	Plain language description of each line item in the 2013 Template
I-1-2	Variance analysis for each line item in the 2013 Template
I-1-3	Variance analysis between forecast and actual values in 2007 Template
I-1-4	Variance analysis for 2013 new CIS opening rate base value
I-1-9	Explanation of how new ABSU CCSA costs are addressed during term of 2007 Template
I-1-11	Explanation of how contract costs other than the new ABSU CCSA costs are determined during term of 2013 Template (given that some do not have 6 year terms)
I-1-12	Copy of ABSU CCSA
I-1-13	Explanation of why no tendering process was undertaken to renew ABSU CCSA
I-1-14	Description of cost efficiency and incentive measures built into the new ABSU CCSA
I-1-15	Discussion of cost drivers in the ABSU CCSA and about how contract revenue is derived
I-1-16	Discussion of self-service features of ABSU CCSA
I-1-18	Explanation of how Enbridge addressed recommendations from Five Point
I-1-19	Explanation of how Enbridge addressed the areas identified as "challenges" in the "Customer Care Service Delivery Strategy" document
I-1-20	Explanation of how ratepayers and others are getting / will get good value from the ABSU CCSA
I-1-21	Details of each of the outsourced contracts, other than the ABSU CCSA
I-2-3	Explanation of Customer Care costs in 2013 Template
I-2-5	Explanation of how costs in 2013 Template were inflated
Tech Conf	Evidence of Five Point at TC, pp. 12-33, 30, 40-41 and 57-58
Tech Conf	Evidence of Enbridge at TC, pp. 62-64 and 98
JTC1.1	Five Point explanation of recommendations made to Enbridge during ABSU negotiations, and Enbridge's responses to those recommendations
JTC1.5	Updated 2013 Template that moves Large Volume Billing costs from line 10a to line 12
JTC 1.6	Updated annual costs for column E (2011 costs) of the 2013 Template (B-5-2)

6. Are the amounts proposed in the 2013 Template (Line 10a) and identified as "ACN, MTP & Collection Agency costs" appropriate for recovery?

As discussed above in the "Terms of Settlement" section (see pages 14 to 18), and subject to all the other provisions of this Agreement, for the purposes of determining an annual cost per Customer for CIS and CC services set out in the Updated 2013 Template, all parties agree to the amounts proposed in Line 10a of the Updated 2013 Template for Accenture, MTP and Collection

Agency Costs from 2013 to 2018. Unlike the approach used in the 2007 Template, the costs set out in line 10a of the Updated 2013 Template do not include the LVB costs, which have been moved to line 12.

Evidence: The evidence in relation to this issue includes the following:

A-2-2	2013 Template
B-2-2	Overview of Relief Sought
B-4-1	Customer Care Costs
B-4-2	Five Point's Customer Care Consultative Report
B-4-3	Enbridge's Customer Care Strategy Document
B-4-4	Stakeholder Steering Committee Statement of Principles
B-5-1	Explanatory Notes re. 2013 Template
B-5-2	Version of 2013 Template Containing Actual/Forecast 2007 to 2012 Costs
I-1-1	Plain language description of each line item in the 2013 Template
I-1-2	Variance analysis for each line item in the 2013 Template
I-1-3	Variance analysis between forecast and actual values in 2007 Template
I-1-9	Explanation of how new ABSU CCSA costs are addressed during term of 2007 Template
I-1-11	Explanation of how contract costs other than the new ABSU CCSA costs are determined during term of 2013 Template (given that some do not have 6 year terms)
I-1-12	Copy of ABSU CCSA
I-1-13	Explanation of why no tendering process was undertaken to renew ABSU CCSA
I-1-14	Description of cost efficiency and incentive measures built into the new ABSU CCSA
I-1-15	Discussion of cost drivers in the ABSU CCSA and about how contract revenue is derived
I-1-16	Discussion of self-service features of ABSU CCSA
I-1-18	Explanation of how Enbridge addressed recommendations from Five Point
I-1-19	Explanation of how Enbridge addressed the areas identified as "challenges" in the "Customer Care Service Delivery Strategy" document
I-1-20	Explanation of how ratepayers and others are getting / will get good value from the ABSU CCSA
I-1-21	Details of each of the outsourced contracts, other than the ABSU CCSA
I-2-3	Explanation of Customer Care costs in 2013 Template
I-2-5	Explanation of how costs in 2013 Template were inflated
Tech Conf	Evidence of Five Point at TC, pp. 12-33, 30, 40-41 and 57-58
Tech Conf	Evidence of Enbridge at TC, pp. 62-64, 70-72, 98, 108-110, 129-130
JTC1.1	Five Point explanation of recommendations made to Enbridge during ABSU negotiations, and Enbridge's responses to those recommendations
JTC1.5	Updated 2013 Template that moves Large Volume Billing costs from line 10a to line 12
JTC 1.6	Updated annual costs for column E (2011 costs) of the 2013 Template (B-5-2)

7. Are the amounts proposed in the 2013 Template (Line 10b) and identified as "MET" appropriate for recovery?

All parties agree that the costs on this line should be aggregated with all other lines (excluding lines 3 and 10a), and forecast on the basis of the per Customer amount and formula described on pages 20 to 22 above. The costs for this line as set in the 2013 Template are for illustrative purposes only, and are not separately validated in isolation from the totals.

Evidence: The evidence in relation to this issue includes the following:

A-2-2	2013 Template
B-2-2	Overview of Relief Sought
B-4-1	Customer Care Costs
B-4-2	Five Point's Customer Care Consultative Report
B-4-3	Enbridge's Customer Care Strategy Document

B-4-4	Stakeholder Steering Committee Statement of Principles
B-5-1	Explanatory Notes re. 2013 Template
B-5-2	Version of 2013 Template Containing Actual/Forecast 2007 to 2012 Costs
I-1-1	Plain language description of each line item in the 2013 Template
I-1-2	Variance analysis for each line item in the 2013 Template
I-1-3	Variance analysis between forecast and actual values in 2007 Template
I-1-11	Explanation of how contract costs other than the new ABSU CCSA costs are determined during term of 2013 Template (given that some do not have 6 year terms)
I-2-3	Explanation of Customer Care costs in 2013 Template
I-2-5	Explanation of how costs in 2013 Template were inflated
Tech Conf	Evidence of Enbridge at TC, p. 110
JTC 1.6	Updated annual costs for column E (2011 costs) of the 2013 Template (B-5-2)

8. Are the amounts proposed in the 2013 Template (Line 10c) and identified as "Postage" appropriate for recovery?

All parties agree that the costs on this line should be aggregated with all other lines (excluding lines 3 and 10a), and forecast on the basis of the per Customer amount and formula described on pages 20 to 22 above. The costs for this line as set in the 2013 Template are for illustrative purposes only, and are not separately validated in isolation from the totals.

Evidence: The evidence in relation to this issue includes the following:

A-2-2	2013 Template
B-2-2	Overview of Relief Sought
B-4-1	Customer Care Costs
B-4-2	Five Point's Customer Care Consultative Report
B-4-3	Enbridge's Customer Care Strategy Document
B-4-4	Stakeholder Steering Committee Statement of Principles
B-5-1	Explanatory Notes re. 2013 Template
B-5-2	Version of 2013 Template Containing Actual/Forecast 2007 to 2012 Costs
I-1-1	Plain language description of each line item in the 2013 Template
I-1-2	Variance analysis for each line item in the 2013 Template
I-1-3	Variance analysis between forecast and actual values in 2007 Template
I-1-11	Explanation of how contract costs other than the new ABSU CCSA costs are determined during term of 2013 Template (given that some do not have 6 year terms)
I-2-3	Explanation of Customer Care costs in 2013 Template
I-2-5	Explanation of how costs in 2013 Template were inflated
Tech Conf	Evidence of Five Point at TC, p. 111
JTC 1.6	Updated annual costs for column E (2011 costs) of the 2013 Template (B-5-2)

9. Are the amounts proposed in the 2013 Template (Line 11) and identified as "Customer Care Licences" appropriate for recovery?

All parties agree that the costs on this line should be aggregated with all other lines (excluding lines 3 and 10a), and forecast on the basis of the per Customer amount and formula described on pages 20 to 22 above. The costs for this line as set in the 2013 Template are for illustrative purposes only, and are not separately validated in isolation from the totals.

Evidence: The evidence in relation to this issue includes the following:

A-2-2	2013 Template
B-2-2	Overview of Relief Sought
B-4-1	Customer Care Costs
B-4-2	Five Point's Customer Care Consultative Report
B-4-3	Enbridge's Customer Care Strategy Document
B-4-4	Stakeholder Steering Committee Statement of Principles
B-5-1	Explanatory Notes re. 2013 Template
B-5-2	Version of 2013 Template Containing Actual/Forecast 2007 to 2012 Costs
I-1-1	Plain language description of each line item in the 2013 Template
I-1-2	Variance analysis for each line item in the 2013 Template
I-1-3	Variance analysis between forecast and actual values in 2007 Template
I-1-4	Variance analysis for 2013 new CIS opening rate base value
I-2-3	Explanation of Customer Care costs in 2013 Template
I-2-5	Explanation of how costs in 2013 Template were inflated
JTC 1.6	Updated annual costs for column E (2011 costs) of the 2013 Template (B-5-2)

10. Are the amounts proposed in the 2013 Template (Line 12) and identified as "Customer Care Backoffice (EGD Staffing)" appropriate for recovery?

All parties agree that the costs on this line should be aggregated with all other lines (excluding lines 3 and 10a), and forecast on the basis of the per Customer amount and formula described on pages 20 to 22 above. The costs for this line as set in the 2013 Template are for illustrative purposes only, and are not separately validated in isolation from the totals.

Evidence: The evidence in relation to this issue includes the following:

A-2-2	2013 Template
B-2-2	Overview of Relief Sought
B-4-1	Customer Care Costs
B-4-2	Five Point's Customer Care Consultative Report
B-4-4	Stakeholder Steering Committee Statement of Principles
B-5-1	Explanatory Notes re. 2013 Template
B-5-2	Version of 2013 Template Containing Actual/Forecast 2007 to 2012 Costs
I-1-1	Plain language description of each line item in the 2013 Template
I-1-2	Variance analysis for each line item in the 2013 Template
I-1-3	Variance analysis between forecast and actual values in 2007 Template
I-1-4	Variance analysis for 2013 new CIS opening rate base value
I-1-23	Explanation of which items in the 2013 Template contain Enbridge's in-house costs
I-2-3	Explanation of Customer Care costs in 2013 Template
I-2-5	Explanation of how costs in 2013 Template were inflated
Tech Conf	Evidence of Enbridge at TC, pp. 70-72, 108-110 and 129-130
JTC1.5	Updated 2013 Template that moves Large Volume Billing costs from line 10a to line 12
JTC 1.6	Updated annual costs for column E (2011 costs) of the 2013 Template (B-5-2)

11. Are the amounts proposed in the 2013 Template (Line 23) and identified as "Total Customer Care Revenue by Year (including repayment of 2007 variance)" appropriate for recovery?

As described above in the "Terms of Settlement" section (see pages 10 to 24), all parties agree that the amounts identified in line 24 as the "smoothed" cost per Customer for each year from 2013 to 2018 are appropriate for recovery. On the assumption that the actual annual numbers of

Customers are the same as those set out in line 17, all parties agree that the amounts set out in line 23 of the Updated 2013 Template for total annual revenue requirement (which total $735M) are appropriate for recovery in the appropriate years. In this regard, it is noted that the actual annual revenue requirement to be recovered each year will vary from line 23, because it will be calculated each year by multiplying the annual "smoothed" cost per Customer in line 24 by Enbridge's updated forecast number of Customers for that year. All parties agree that this adjustment from the $735 million as a result of changes in the number of Customers is appropriate.

In conjunction with this "smoothing" approach, parties agree to the establishment and operation of a rate smoothing deferral account for each year from 2013 to 2018, as described above in the "Terms of Settlement" section.

Evidence: The evidence in relation to this issue includes the following:

A-2-2	2013 Template
B-2-2	Overview of Relief Sought
B-5-1	Explanatory Notes re. 2013 Template
B-5-2	Version of 2013 Template Containing Actual/Forecast 2007 to 2012 Costs
I-1-6	Inflation factor approved in each year of the IRM Plan
I-1-7	Inflation factors proposed for CIS and CC costs
I-1-8	Explanation of the smoothing mechanisms built into the 2013 Template
I-1-23	Explanation of which items in the 2013 Template contain Enbridge's in-house costs
I-2-5	Explanation of how costs in 2013 Template were inflated
Tech Conf	Evidence of Enbridge at TC, pp. 64-69, 72-80, 86-92, 115-118, 131-132 and 137-144
JTC1.4	Calculation of annual cost per customer for CIS and CC services up to 2018
JTC1.7	Forecast of GDP IPI FDD factor for 2012 to 2018
JTC 1.9	Update of inflation factors proposed for CIS and CC costs
JTC1.10	Explanation of difference between 2012 and 2013 smoothed revenue requirement in 2013 Template
JTC 1.11	Recalculation of smoothed annual revenue requirement in 2013 Template from 2012 to 2018, to reflect equal annual increases
JTC 1.13	Revised version of 2013 Template that removes one-time costs associated with acquiring new CIS and initial CCSA with ABSU

12. Is the proposed opening 2013 Rate Base amount of $76.9 million for the CIS asset appropriate?

As described above in the "Terms of Settlement" section (see pages 12 to 14), all parties agree to the proposed opening 2013 Rate Base amount of $76.9 million for the new CIS asset. See also the response to Issue #1.

Evidence: The evidence in relation to this issue includes the following:

A-2-2	2013 Template
B-2-2	Overview of Relief Sought
B-3-1	CIS Costs
B-3-2	Five Point's CIS Project Close-Out Report
B-3-4	Revenue Requirement Impact of New CIS Opening Rate Base Value
B-5-1	Explanatory Notes re. 2013 Template
I-1-1	Plain language description of each line item in the 2013 Template
I-1-2	Variance analysis for each line item in the 2013 Template
I-1-3	Variance analysis between forecast and actual values in 2007 Template
I-1-4	Variance analysis for 2013 new CIS opening rate base value

I-1-10	Rationale for the CIS cost recovery over two six-year spans
I-1-33	Copy of 2007 Settlement Agreement
I-2-2	Explanation of CIS costs in 2013 Template
Tech Conf	Evidence of Five Point at TC, pp. 10-12, 30, 34-40 and 42-47
Tech Conf	Evidence of Enbridge at TC, pp. 60-62, 84-86, 92-98, 99-101 and 122-123
JTC1.2	Five Point slide deck re. CIS implementation project costs
JTC1.3	Annual cost per customer for CIS services up to 2018

13. Is the annual adjustment factor (or inflation factor) of 1.77580% built into the 2013 Template appropriate?

As described above in the "Terms of Settlement" section (see pages 10 to 24), the Updated 2013 Template is different from the 2013 Template filed with this Application. The Updated 2013 Template uses different inflation factors for Enbridge's cost per Customer (derived as a function of the underlying costs) and for the smoothed cost per Customer amount to be recovered each year in revenue requirement. All parties agree that the inflators used for the purpose of creating costs per Customer for 2014 to 2018 (which apply an annual increase of 0.6%), and for creating the smoothed annual cost per Customer to be recovered each year in revenue requirement (which apply an annual increase of 2.2%, but use a lower 2013 base cost per Customer amount) are compromise numbers that create reasonable and appropriate results in this case, but also agree that these inflators will not be relied upon as a precedent or indicator of an appropriate inflator of costs, revenue requirement or rates in any other Enbridge proceeding.

Evidence: The evidence in relation to this issue includes the following:

A-2-2	2013 Template
B-2-2	Overview of Relief Sought
B-5-1	Explanatory Notes re. 2013 Template
B-5-2	Version of 2013 Template Containing Actual/Forecast 2007 to 2012 Costs
I-2-5	Explanation of how costs in 2013 Template were inflated
Tech Conf	Evidence of Enbridge at TC, pp. 74-78, 86-88 and 131-132
JTC1.7	Forecast of GDP IPI FDD factor for 2012 to 2018
JTC 1.9	Update of inflation factors proposed for CIS and CC costs

14. Is it appropriate for the cost recovery to span two 6-year fiscal periods (2007- 2012 and 2013-2018 as shown on the 2013 Template) when the economic life of the CIS asset is ten years?

All parties agree that the recovery of revenue requirement for the new CIS asset over a 10 year term from 2009 to 2018 is appropriate. That is consistent with the fact that the new CIS asset is assumed to have a 10 year economic life, with an assumed in-service date of January 1, 2009.

All parties agree that it is appropriate that the additional cost allowances included in the January 1, 2013 $76.9M opening rate base amount for the new CIS asset should continue into 2019 in recognition of the actual CIS in-service date of September 1, 2009. The result, as set out at Ex. B-3-4, is that Enbridge will collect approximately $760,000 in revenue requirement for the new CIS asset in 2019.

Evidence: The evidence in relation to this issue includes the following:

A-2-2	2013 Template
B-2-2	Overview of Relief Sought
B-3-1	CIS Costs
B-3-4	Revenue Requirement Impact of New CIS Opening Rate Base Value
B-5-1	Explanatory Notes re. 2013 Template
I-1-10	Rationale for the CIS cost recovery over two six-year spans

15. Are the efficiency and performance measures that are built into the Accenture contract adequate and appropriate?

As described above in the “Terms of Settlement” section (see pages 14 to 18), all parties agree that, with respect to customer care associated with regulated Customers, and excluding those aspects that relate to unregulated and non-utility activities, such as open bill access and ABC, the extended and updated Accenture CCSA, and the associated cost per Customer, is prudent and appropriate. The service levels and performance measures in the revised and extended CCSA are superior to those which are included in the current CCSA. Under the revised and extended CCSA, Accenture has agreed to provide its services at a predetermined cost for an extended period of time on a per-Customer basis. Accenture therefore takes the risk of achieving or not achieving productivity benefits. Enbridge and its ratepayers get the benefit of predetermined customer care costs which are comparable to current costs through to the end of 2018. On this basis, no party asserts that with respect to regulated activities the Accenture contract lacks adequate or appropriate efficiency and performance measures.

Evidence: The evidence in relation to this issue includes the following:

B-4-1	Customer Care Costs
B-4-2	Five Point’s Customer Care Consultative Report
B-4-3	Enbridge’s Customer Care Strategy Document
I-1-14	Description of cost efficiency and incentive measures built into the new ABSU CCSA
I-1-16	Discussion of self-service features of ABSU CCSA
I-1-20	Explanation of how ratepayers and others are getting and will get good value from the ABSU CCSA
Tech Conf	Evidence of Five Point at TC, pp. 12-33, 30, 40-41 and 57-58
Tech Conf	Evidence of Enbridge at TC, pp. 60-62, 84-86, 92-98, 99-101 and 122-123
JTC1.1	Five Point explanation of recommendations made to Enbridge and Enbridge’s responses

16. Are the efficiency and performance measures that are built into all the subject outsourced contracts, other than the Accenture contract, adequate and appropriate?

As described in the “Terms of Settlement” section (see pages 18 to 22), all parties agree that the costs included on a cost per Customer basis as the “other CIS and CC costs” (from lines 4, 5, 6, 10b, 10c, 11 and 12 of the Updated 2013 Template) are in the aggregate prudent and appropriate. Those lines include costs associated with outsourced contracts, such as the MET (meter reading) contract. Given the negotiated reduction in costs from the level forecast by Enbridge for 2013, and given the certainty that will result from annual increases in cost per Customer that are set at less than 1% (on a non-smoothed basis), all parties agree that in aggregate the cost consequences of those contracts are reasonable.

Evidence: The evidence in relation to this issue includes the following:

B-4-1	Customer Care Costs
B-4-2	Five Point's Customer Care Consultative Report
B-4-3	Enbridge's Customer Care Strategy Document
I-1-14	Description of cost efficiency and incentive measures built into the new ABSU CCSA
I-1-16	Discussion of self-service features of ABSU CCSA
I-1-20	Explanation of how ratepayers and others are getting and will get good value from the ABSU CCSA
Tech Conf	Evidence of Five Point at TC, pp. 12-33, 30, 40-41 and 57-58
Tech Conf	Evidence of Enbridge at TC, pp. 60-62, 84-86, 92-98, 99-101 and 122-123
JTC1.1	Five Point explanation of recommendations made to Enbridge during ABSU negotiations, and Enbridge's responses to those recommendations
I-1-21	Details of each of the outsourced contracts, other than the ABSU CCSA

17. Is Y-Factor treatment of all of the subject costs appropriate in the next generation of the Board's Incentive Ratemaking?

All parties agree that Y-factor treatment of all the subject costs is appropriate in any next generation of IRM ratemaking that applies to Enbridge. While all parties recognize that the nature of a large number of the costs in the Updated 2013 Template are such that they would not normally be considered Y-factors, the fact that the annual levels of these costs have been predetermined by settlement over a number of years means that they should be included in any IRM-based rates for Enbridge in the same manner as traditional Y-Factors. This position is supported by the fact that the cost per Customer set out in the Updated 2013 Template was established using an IRM-type approach, where a base level for all costs was established, and then an annual inflation factor was applied to those base costs to establish costs per Customer for successive years. Given that the annual revenue requirements that will be determined each year are a function of the costs per Customer that were established using an IRM-type approach, it is appropriate that the annual revenue requirement amounts be passed through as a Y-Factor each year of any future IRM term, or as a pass-through amount in any cost of service ratemaking year between 2013 and 2018.

Evidence: The evidence in relation to this issue includes the following:

I-1-22	Explanation of how there is no variance account / true-up for differences between amounts in 2007 and 2013 Template and actual costs
I-1-31	Board Staff Interrogatory #31

18. Is the nature of the tendering process carried out adequate and appropriate in the circumstances?

As described above in the "Terms of Settlement" section (see pages 14 to 18), all parties agree that the process followed by Enbridge in considering options for customer care services after the expiry of the current Accenture CCSA (as of April 1, 2012), and then negotiating an revised and extended CCSA with Accenture was appropriate and provided proper ratepayer protection in developing the pricing and terms of the CCSA for the term covered by the Updated 2013 Template. All parties agree that the procurement approach used was unique to the particular circumstances, and its applicability, if at all, as a precedent for future procurements by Enbridge or any other utility is dependent on the particular circumstances in that future procurement.

Evidence: The evidence in relation to this issue includes the following:

B-2-2	Overview of Relief Sought
B-4-1	Customer Care Costs
B-4-2	Five Point's Customer Care Consultative Report
B-4-3	Enbridge's Customer Care Strategy Document
B-4-4	Stakeholder Steering Committee Statement of Principles
I-1-13	Explanation of why no tendering process was undertaken to renew ABSU CCSA
I-1-18	Explanation of how Enbridge addressed recommendations from Five Point
JTC1.1	Five Point explanation of recommendations made to Enbridge during ABSU negotiations, and Enbridge's responses to those recommendations

19. Should any of the proposed costs be classified as Non-Utility costs?

As described above in the "Terms of Settlement" section (see page 25), all parties agree that any issue over whether any of the costs set out in the Updated 2013 Template (and the associated annual cost per Customer) should be classified as "Non-Utility Costs" with the consequential possibility that some of the costs may be allocated to third parties is more appropriately raised as part of Enbridge's ratesetting proceedings for 2013 and beyond, to be considered in light of the Company's activities at that time.

Evidence: The evidence in relation to this issue includes the following:

A-2-2	2013 Template
B-5-1	Explanatory Notes re. 2013 Template
B-5-2	Version of 2013 Template Containing Actual/Forecast 2007 to 2012 Cost
I-1-1	Plain language description of each line item in the 2013 Template
I-1-24	Explanation of non-utility services provided related to costs set out in this Application
I-1-25	Explanation of operations of CIS and CC systems in serving non-utility stakeholders
I-1-26	Explanation of whether non-utility services are supported by the CIS and CC systems
I-1-27	Explanation of open bill features associated with this Application and how open bill revenue is shared
I-1-28	Explanation of how bad debt, open bill access and agent billing and collection costs are treated in the context of this Application
I-2-6	Explanation of current and future open bill access costs and revenues
Tech Conf	Evidence of Enbridge at TC, pp. 105-107, 112-114 and 118-122
JTC1.12	Breakdown of information provided in I-2-6
JTC1.14	Explanation of costs removed from ABSU CCSA and moved to open bill and agent billing and collection

20. Is the benchmarking of costs appropriate for use in the Board's assessment of the reasonableness of the costs?

All parties agree that the benchmarking information provided in this application from EquaTerra and Five Point is appropriate for use in the Board's assessment of the reasonableness of the costs in lines 3 and 10a of the Updated 2013 Template. All parties further agree that the benchmarking information from EquaTerra and Five Point support a finding that the costs set out for the new CIS asset (line 3) and the revised and extended CCSA (line 10a) are reasonable.

Evidence: The evidence in relation to this issue includes the following:

B-2-2	Overview of Relief Sought
B-3-1	CIS Costs
B-3-2	Five Point's CIS Project Close-Out Report
B-4-1	Customer Care Costs
B-4-2	Five Point's Customer Care Consultative Report
B-4-3	Enbridge's Customer Care Strategy Document (including EquaTerra benchmarking evidence)
B-4-4	Stakeholder Steering Committee Statement of Principles
I-1-13	Explanation of why no tendering process was undertaken to renew ABSU CCSA
I-1-17	Statement of Work for Five Point consulting services
I-1-29	EquaTerra benchmarking reports
Tech Conf	Evidence of Five Point at TC, pp. 10-12, 30, 34-40 and 42-47
JTC1.2	Five Point slide deck re. CIS implementation project costs

21. Is the Application consistent with the 2007 Settlement Agreement in all material respects?

As described above in the "Terms of Settlement" section (see pages 12 to 14), the one change to the details of the 2007 Settlement Agreement, which change was contemplated by the terms of that Settlement Agreement, is that all parties agree that the proper opening rate base value for the new CIS as of January 1, 2013 is $76.9 million.

Beyond that, all parties agree that this Settlement Agreement is consistent with the 2007 Settlement Agreement in all material respects. The terms of this Settlement Agreement do not change any items in the 2007 Template that was attached to the 2007 Settlement Agreement, and in particular the terms of this Settlement Agreement do not in any way impact upon the revenue requirement being recovered for CIS and CC services in 2011 and 2012, as set out in the 2007 Settlement Agreement. In addition, to large extent the approach taken in the current Settlement Agreement, and the Updated 2013 Template, replicates the approach taken in the 2007 Settlement Agreement. On page 28 above the parties have set out the material differences in approach used in this Agreement vs. the 2007 Settlement Agreement. All of those differences in approach are either the result of changed circumstances (such as no continuing need for true-up provisions) or updates to the concepts in the 2007 Settlement Agreement (such as the change of smoothing to a per Customer basis).

Evidence: The evidence in relation to this issue includes the following:

I-1-22	Explanation of how there is no variance account / true-up for differences between amounts in 2007 and 2013 Template and actual costs
I-1-30	Explanation of how the Application is consistent with the 2007 Settlement Agreement
I-1-33	Copy of 2007 Settlement Agreement
I-1-34	Copy of EB-2006-0034 transcript where OEB approved 2007 Settlement Agreement

22. Is the Application consistent with the existing IRM mechanism and will it be applicable to the future IRM mechanism?

All parties agree that this Settlement Agreement will have no impact upon the current IRM mechanism, as it does not contemplate any revenue requirement impacts during the term of the current IRM term (up to December 31, 2012).

All parties further agree that this Settlement Agreement will be applicable to any future IRM mechanism that applies to Enbridge during the term of the Updated 2013 Template. As explained above in the “Terms of Settlement” section, in a future IRM mechanism, the annual CIS and CC revenue requirement (calculated by multiplying the applicable cost per Customer by the applicable number of Customers) would be passed through into overall revenue requirement as a Y-factor, which is a continuation of the current practice.

Evidence: The evidence in relation to this issue includes the following:

I-1-22	Explanation of how there is no variance account / true-up for differences between amounts in 2007 and 2013 Template and actual costs
I-1-31	Explanation of how the Application is consistent with the existing IRM mechanism and how it will be applicable to the future IRM mechanism

23. Is the rate class cost allocation methodology appropriate?

As described above in the “Terms of Settlement” section (see page 24), all parties agree that it is not necessary to address any issues in this proceeding about the allocation of the costs set out in the Updated 2013 Template to rate classes. All parties agree that any issues about how the costs set out in the Updated 2013 Template are allocated to rate classes may be raised as part of Enbridge’s ratesetting proceedings for 2013 and beyond.

Evidence: The evidence in relation to this issue includes the following:

I-1-32	Explanation of rate class allocation and bill impact of the cost consequences of the 2013 Template
I-2-7	Explanation of cost allocations and bill impact associated with the 2013 Template

24. Are the customer bill impacts appropriate?

As described above in the “Terms of Settlement” section (see pages 24 to 25), all parties agree that the customer bill impacts of this Settlement Agreement are appropriate.

Evidence: The evidence in relation to this issue includes the following:

I-1-32	Explanation of rate class allocation and bill impact of the cost consequences of the 2013 Template
I-2-7	Explanation of cost allocations and bill impact associated with the 2013 Template

"Updated 2013 Template"

#	Category of Cost	A 2007A	B 2008A	C 2009A	D 2010A	E 2011	F 2012	G 2007-2012 Total	H 2013	I 2014	J 2015	K 2016	L 2017	M 2018	N 2013-2018 Total
	CIS Related Categories														
1	*Old CIS Licence Fee*														
2	*Old CIS Hosting and Support*	$14,200,000	$9,800,000	$4,900,000	$0	$0	$0	$28,900,000	$0	$0	$0	$0	$0	$0	$0
2a	*Incumbent (CWLP) CIS Services being provided from January to March 2007*														
3	*New CIS Capital Cost @ Board Approved **36%** Equity*	$0	$0	$950,000	($5,260,000)	$25,890,000	$24,910,000	$46,490,000	$25,420,000	$24,380,000	$23,320,000	$22,320,000	$21,310,000	$20,260,000	$137,010,000
4	*New CIS Hosting and Support*	$0	$0	$4,350,000	$8,700,000	$8,700,000	$8,700,000	$30,450,000	$7,107,911	$7,355,128	$7,628,087	$7,934,598	$8,237,974	$8,350,643	$46,614,341
5	*CIS Backoffice (EGD Staffing)*	$1,000,000	$1,030,000	$2,000,000	$2,060,000	$2,121,800	$2,185,454	$10,397,254	$2,611,281	$2,711,307	$2,822,435	$2,946,817	$3,070,921	$3,124,554	$17,287,314
6	*SAP Licence Fees*	$0	$0	$1,113,500	$2,227,000	$2,227,000	$2,227,000	$7,794,500	$2,097,486	$2,188,393	$2,289,104	$2,401,538	$2,514,778	$2,571,070	$14,062,369
7	*SAP Modifications*	$0	$0	$1,000,000	$1,000,000	$0	$0	$2,000,000	$0	$0	$0	$0	$0	$0	$0
	Subtotal	**$15,200,000**	**$10,830,000**	**$14,313,500**	**$8,727,000**	**$38,938,800**	**$38,022,454**	**$126,031,754**	**$37,236,678**	**$36,634,828**	**$36,059,626**	**$35,602,954**	**$35,133,673**	**$34,306,266**	**$214,974,024**
	Customer Care Related Categories														
8	*Incumbent (CWLP) Customer Care Services being provided from - January to March 2007*	$16,900,000	$0	$0	$0	$0	$0	$16,900,000	$0	$0	$0	$0	$0	$0	$0
9	*Customer Care Transition Service Provider Contract Cost - ABSU April, 2007 to Sept. 30, 2008*	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
10	*New Service Provider Contract Cost*	$47,803,098	$66,069,140	$67,251,948	$68,885,212	$ 70,731,432	$ 72,542,088	$393,282,918	$69,831,641	$73,010,836	$76,245,351	$79,424,943	$82,682,196	$86,349,139	$467,544,106
10a	*ACN, MTP & Collection Agency costs*	-	-	-	-	-	-	-	46,022,920	47,751,346	49,354,748	50,736,108	52,168,283	54,755,784	300,789,189
10b	*MET*	-	-	-	-	-	-	-	$9,583,608	$9,957,362	$10,465,311	$11,034,609	$11,610,927	$11,904,271	$64,556,086
10c	*Postage*	-	-	-	-	-	-	-	$14,225,114	$15,302,128	$16,425,293	$17,654,226	$18,902,986	$19,689,083	$102,198,830
11	*Customer Care Licences*	$1,400,000	$1,400,000	$1,400,000	$1,400,000	$1,400,000	$1,400,000	$8,400,000	$1,289,750	$1,345,649	$1,407,576	$1,476,712	$1,546,344	$1,580,958	$8,646,987
12	*Customer Care Backoffice (EGD staffing)*	$3,100,000	$3,193,000	$3,288,790	$3,387,454	$3,489,077	$3,593,750	$20,052,071	$6,484,645	$6,792,953	$7,129,522	$7,506,674	$7,876,385	$8,044,707	$43,834,885
13	*Customer Care Procurement Costs*	$0	$980,000	$980,000	$980,000	$980,000	$980,000	$4,900,000	$0	$0	$0	$0	$0	$0	$0
14	*Transition Costs - Consultants and ISP*	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
15	*Transition Costs - EGD Staffing*														
	Subtotal Customer Care Only	**69,203,098**	**71,642,140**	**72,920,738**	**74,652,666**	**76,600,509**	**78,515,838**	**443,534,989**	**77,606,036**	**81,149,437**	**84,782,449**	**88,408,328**	**92,104,924**	**95,974,803**	**520,025,978**
16	**Total CIS & Customer Care**	$84,403,098	$82,472,140	$87,234,238	$83,379,666	$115,539,309	$116,538,292	$569,566,743	$114,842,714	$117,784,265	$120,842,075	$124,011,282	$127,238,597	$130,281,069	$735,000,002
17	*Number of Customers*	1,831,283	1,878,004	1,925,563	1,973,575	2,021,588	2,069,600	11,699,613	2,059,959	2,100,317	2,142,191	2,185,464	2,229,173	2,269,074	12,986,178
17a	**Total cost/customer**	$46.09	$43.91	$45.30	$42.25	$57.15	$56.31		$55.75	$56.08	$56.41	$56.74	$57.08	$57.42	
22	***The Normalized 2008 Customer Care Revenue Requirement will be the Normalized 2007 Customer Care Revenue Requirement, plus or minus the IR annual adjustment that is approved for Enbridge Gas Distribution.***	**$90,799,999**	**$92,412,426**	**$94,053,486**	**$95,723,687**	**$97,423,549**	**$99,153,596**	$569,566,743							
23	*Total Customer Care Revenue By Year (Including repayment of 2007 variance)*	$ 90,800,000	$ 92,412,426	$ 94,053,486	$ 95,723,687	$ 97,423,549	$ 99,153,596	$569,566,743	110,207,807	114,837,889	119,703,021	124,806,484	130,101,959	135,342,842	735,000,002
24	*Normalized Customer Care Revenue Requirement Per Customer without Bad Debt*	$ 49.58	$ 49.21	$ 48.84	$ 48.50	$ 48.19	$ 47.91		$ 53.50	$ 54.68	$ 55.88	$ 57.11	$ 58.36	$ 59.65	

Filed: 2016-10-04
EB-2016-0215
Exhibit D1
Tab 3
Schedule 3
Page 1 of 1

"Updated CIS / CC Template for 2017"

#	Category of Cost	A 2007A	B 2008A	C 2009A	D 2010A	E 2011	F 2012	G 2007-2012 Total	H 2013	I 2014	J 2015	K 2016	L 2017	M 2018	N 2013-2018 Total
	CIS Related Categories														
1	Old CIS Licence Fee														
2	Old CIS Hosting and Support	$14,200,000	$9,800,000	$4,900,000	$0	$0	$0	$28,900,000	$0	$0	$0	$0	$0	$0	$0
2a	Incumbent (CWLP) CIS Services being provided from January to March 2007														
3	New CIS Capital Cost @ Board Approved **36%** Equity	$0	$0	$950,000	($5,260,000)	$25,890,000	$24,910,000	$46,490,000	$25,420,000	$24,380,000	$23,320,000	$22,320,000	$21,310,000	$20,260,000	$137,010,000
4	New CIS Hosting and Support	$0	$0	$4,350,000	$8,700,000	$8,700,000	$8,700,000	$30,450,000	$7,107,911	$7,355,128	$7,628,087	$7,934,598	$8,237,974	$8,350,643	$46,614,341
5	CIS Backoffice (EGD Staffing)	$1,000,000	$1,030,000	$2,000,000	$2,060,000	$2,121,800	$2,185,454	$10,397,254	$2,611,281	$2,711,307	$2,822,435	$2,946,817	$3,070,921	$3,124,554	$17,287,314
6	SAP Licence Fees	$0	$0	$1,113,500	$2,227,000	$2,227,000	$2,227,000	$7,794,500	$2,097,486	$2,188,393	$2,289,104	$2,401,538	$2,514,778	$2,571,070	$14,062,369
7	SAP Modifications	$0	$0	$1,000,000	$1,000,000	$0	$0	$2,000,000	$0	$0	$0	$0	$0	$0	$0
	Subtotal	**$15,200,000**	**$10,830,000**	**$14,313,500**	**$8,727,000**	**$38,938,800**	**$38,022,454**	**$126,031,754**	**$37,236,678**	**$36,634,828**	**$36,059,626**	**$35,602,954**	**$35,133,673**	**$34,306,266**	**$214,974,024**
	Customer Care Related Categories														
8	Incumbent (CWLP) Customer Care Services being provided from - January to March 2007	$16,900,000	$0	$0	$0	$0	$0	$16,900,000	$0	$0	$0	$0	$0	$0	$0
9	Customer Care Transition Service Provider Contract Cost - ABSU April, 2007 to Sept. 30, 2008	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
10	New Service Provider Contract Cost	$47,803,098	$66,069,140	$67,251,948	$68,885,212	$ 70,731,432	$ 72,542,088	$393,282,918	$69,831,641	$73,010,836	$76,245,351	$79,424,943	$82,682,196	$86,349,139	$467,544,106
10a	ACN, MTP & Collection Agency costs	-	-	-	-	-	-	-	46,022,920	47,751,346	49,354,748	50,736,108	52,168,283	54,755,784	300,789,189
10b	MET	-	-	-	-	-	-	-	$9,583,608	$9,957,362	$10,465,311	$11,034,609	$11,610,927	$11,904,271	$64,556,086
10c	Postage	-	-	-	-	-	-	-	$14,225,114	$15,302,128	$16,425,293	$17,654,226	$18,902,986	$19,689,083	$102,198,830
11	Customer Care Licences	$1,400,000	$1,400,000	$1,400,000	$1,400,000	$1,400,000	$1,400,000	$8,400,000	$1,289,750	$1,345,649	$1,407,576	$1,476,712	$1,546,344	$1,580,958	$8,646,987
12	Customer Care Backoffice (EGD staffing)	$3,100,000	$3,193,000	$3,288,790	$3,387,454	$3,489,077	$3,593,750	$20,052,071	$6,484,645	$6,792,953	$7,129,522	$7,506,674	$7,876,385	$8,044,707	$43,834,885
13	Customer Care Procurement Costs	$0	$980,000	$980,000	$980,000	$980,000	$980,000	$4,900,000	$0	$0	$0	$0	$0	$0	$0
14	Transition Costs - Consultants and ISP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
15	Transition Costs - EGD Staffing														
	Subtotal Customer Care Only	**69,203,098**	**71,642,140**	**72,920,738**	**74,652,666**	**76,600,509**	**78,515,838**	**443,534,989**	**77,606,036**	**81,149,437**	**84,782,449**	**88,408,328**	**92,104,924**	**95,974,803**	**520,025,978**
16	**Total CIS & Customer Care**	$84,403,098	$82,472,140	$87,234,238	$83,379,666	$115,539,309	$116,538,292	$569,566,743	$114,842,714	$117,784,265	$120,842,075	$124,011,282	$127,238,597	$130,281,069	$735,000,002
17	Number of Customers	1,831,283	1,878,004	1,925,563	1,973,575	2,021,588	2,069,600	11,699,613	2,059,959	2,100,317	2,142,191	2,185,464	2,229,173	2,269,074	12,986,178
17a	**Total cost/customer**	$46.09	$43.91	$45.30	$42.25	$57.15	$56.31		$55.75	$56.08	$56.41	$56.74	$57.08	$57.42	
22	***The Normalized 2008 Customer Care Revenue Requirement will be the Normalized 2007 Customer Care Revenue Requirement, plus or minus the IR annual adjustment that is approved for Enbridge Gas Distribution.***	**$90,799,999**	**$92,412,426**	**$94,053,486**	**$95,723,687**	**$97,423,549**	**$99,153,596**	$569,566,743							
23	Total Customer Care Revenue By Year (Including repayment of 2007 variance)	$ 90,800,000	$ 92,412,426	$ 94,053,486	$ 95,723,687	$ 97,423,549	$ 99,153,596	$ 569,566,743	110,207,807	114,837,889	119,703,021	124,806,484	130,101,959	135,342,842	735,000,002
24	Normalized Customer Care Revenue Requirement Per Customer without Bad Debt	$ 49.58	$ 49.21	$ 48.84	$ 48.50	$ 48.19	$ 47.91		$ 53.50	$ 54.68	$ 55.88	$ 57.11	$ 58.36	$ 59.65	
25	**Updated Line 17 Number of customers forecast for 2017 (2013 - 2016 are Board Approved customer forecasts and 2018 is the placeholder from EB-2012-0459)**								**2,059,959**	**2,086,534**	**2,114,261**	**2,143,429**	**2,168,434**	**2,242,859**	
26	**Updated Line 16 Total CIS & Customer Care costs**								**$ 114,842,714**	**$ 117,011,324**	**$ 119,266,530**	**$ 121,626,061**	**$ 123,771,686**	**$ 128,775,910**	
27	**Updated Line 23 Total Customer Care Revenue by year**								**$ 110,207,807**	**$ 114,084,283**	**$ 118,142,327**	**$ 122,405,968**	**$ 126,557,029**	**$ 133,779,203**	

Witnesses: D. McIlwraith
D. Small

2017 DSM FORECAST BUDGET

1. The Ontario Energy Board (the “Board”) rendered its Decision regarding Enbridge’s DSM Multi-Year Plan in EB-2015-0049 on February 24, 2016. Enbridge is currently operating in the second year of the six-year DSM Framework spanning from 2015 to 2020, with a Mid-Term Review anticipated by June 1, 2018.

2. In the EB-2015-0049 Decision, the Board approved a 2017 DSM budget of $62.9 million.

3. Under the rate adjustment framework approved by the Board in EB-2012-0459, the Company is to update the annual DSM budget amount to be included within final Allowed Revenue amounts for each of 2015 to 2018 to those annual amounts approved within the EB-2015-0049 Multi-Year DSM Plan.

4. Any variance between the DSM amount included within 2017 Allowed Revenue and the actual DSM amounts incurred in 2017 will be recorded in the Demand Side Management Variance Account (“DSMVA”).

5. Amounts recorded in the DSMVA will include variances in DSM program costs consistent with the Board’s Filing Guidelines to the Demand Side Management Framework for Natural Gas Distributors (2015 to 2020). Amounts recorded in the DSMVA will also include variances in expenditures relating to evaluation work undertaken by the Company, evaluation work initiated by Board Staff or the Board’s Evaluation Contractor, the Board’s Natural Gas Conservation Potential Study, and Enbridge’s Collaboration and Innovation Fund consistent with the Board’s Decision in EB-2015-0049.

6. Distinct from the DSMVA, the Company's actual DSM spending in 2017 may also vary from the DSM amounts within the 2017 Allowed Revenue where Enbridge is able to make use of funds in the Demand Side Management Cost-Efficiency Incentive Deferral Account ("DSMCEDA"). The DSMCEDA may include funds which represent the difference between Enbridge's approved 2016 DSM budget and the actual amount spent to achieve Enbridge's total 2016 Cumulative Cubic Metres of natural gas ("CCM") targets made up of all 100% CCM targets across all programs. Recording and use of this variance is consistent with the Accounting Order filed by Enbridge on April 26, 2016 as Appendix C of its Draft Rate Order in EB-2015-0049, and subsequently approved by the Board in its Final Decision and Rate Order issued on May 12, 2016.

7. Similarly, the Company will also track and credit to the DSMCEDA differences between the DSM amounts within the 2017 Allowed Revenue and the actual amount spent to achieve Enbridge's total 2017 CCM targets made up of all 100% CCM targets across all programs. Any amounts recorded in this account will be available to use in meeting the Company's targets in a subsequent year over the 2015 to 2020 DSM term.

PENSION / OPEB 2017 UPDATED FORECAST

1. Within the EB-2012-0459 Decision with Reasons, the Ontario Energy Board (the “Board”) determined that for each of the years between 2015 to 2018, Pension and OPEB expenses within Operations & Maintenance costs are to be re-forecast annually and included within an updated calculation of final Allowed Revenue to be filed within a rate adjustment application for each of those fiscal years. The updated total Allowed Revenue replaces the 2017 placeholder Allowed Revenue information which was filed at Appendix A, pages 25 to 32 within the Board’s Decision and Rate Order in EB-2012-0459.

2. Enbridge uses Mercer Canada Limited (“Mercer”), to review, update and forecast its required annual Pension and OPEB accrual expense and cash requirement. The 2017 annual Pension and OPEB accrual expense, as provided by Mercer, is forecasted at $24.73 million; shown as “P&L Charge (Credit)” within the Mercer Reports. The 2017 annual Pension and OPEB cash requirement, as provided by Mercer, is forecasted at $51.43 million; shown as “Total Annual Employer Contributions” within Mercer’s Report. Mercer’s Report is attached as Appendix 1 of this Exhibit.

3. The 2017 forecasted annual Pension and OPEB accrual expense and cash requirement is comprised of the following:

Witnesses: J. Barradas
J. Shem

	Plan	2017 Forecasted Accrual Expense	2017 Forecasted Cash Requirement
1.	Enbridge RPP Plan	$17.50 million	$43.09 million
2.	Enbridge SERP Plan	$0.04 million	$0.26 million
3.	Enbridge SSERP Plan	($0.15 million)	Nil
4.	Enbridge portion of Enbridge Inc's RPP Plan	($0.18 million)	$0.03 million
5.	Enbridge's portion of Enbridge Inc's SPP Plan	$1.51 million	$2.66 million
6.	DC Plan	$0.85 million	$0.85 million
7.	OPEB Plan	$5.16 million	$4.54 million
8.	Total Pension and OPEB	$24.73 million	$51.43 million

4. The impact of the updated Pension & OPEB accrual expense and cash requirement can be seen and is explained in evidence at Exhibit D1, Tab 1, Schedule 2 and Exhibit D1, Tab 6, Schedule 2.

Benedict O. Ukonga, FSA, FCIA
Principal

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Jason Shem
Supervisor Financial Reporting
Enbridge Gas Distribution Inc.
500 Consumers Road
North York, ON M5J 1P8

28 June 2016

Subject: Enbridge Gas Distribution Inc. Estimated 2017 Pension and Benefit Expense and Cash Contributions

Dear Jason,

At your request, we have prepared an estimate of Enbridge Gas Distribution Inc.'s ("EGDI") share of pension and benefits expense and cash contributions in 2017 for the following pension and non-pension post retirement plans:

- The Pension Plan for the Employees of Enbridge Gas Distribution Inc. and Affiliates (the "EGD RPP");
- The Retirement Plan for the Employees of Enbridge Inc. and Affiliates (the "EI RPP");
- The Enbridge Supplemental Pension Plan (the "SPP");
- The Supplementary Executive Retirement Plan of Enbridge Gas Distribution and Affiliates (the "SERP");
- The Supplementary Senior Executive Retirement Plan of Enbridge Gas Distribution Inc. (the "SSERP"); and
- The Non-pension Post Retirement Plan for Employees of Enbridge Gas Distribution Inc. (the "OPEB Plan")

Actual pension and benefits expense and cash funding requirements in respect of 2017 may differ from the amounts estimated here, and will be based on future economic conditions and the respective plans' economic and demographic experiences. We understand these estimates will be provided to the Ontario Energy Board (the "OEB") in conjunction with EGDI's application for recovery of pension and benefits costs from ratepayers.

The information presented in this letter is prepared for the internal use of EGDI and for submitting to the OEB. This information is not intended or suitable for any other purpose.

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A summary of the projections are attached to this letter as follows:

- Appendix A – Summary of estimated 2017 US GAAP pension expense for EGDI's share of the EGD RPP, EI RPP, SPP, SERP, SSERP, and OPEB Plan.
- Appendix B – Summary of EGDI's estimated 2017 contributions to the EGD RPP, EI RPP, SPP, SERP, SSERP, and OPEB Plan.
- Appendix C contains important notices relevant to these projections.

Basis of Accounting Projections

The EGD RPP, SERP, and SSERP projections are based on membership data as at December 31, 2015 and the same assumptions (with the exception of the discount rate), methods and policies as the December 31, 2015 fiscal year end disclosures.

We have projected the results of the December 31, 2014 actuarial valuations of the EI RPP and SPP for US GAAP financial reporting purposes forward to 2016. The membership data is as at December 31, 2014 and we have not updated the membership data to reflect demographic changes since that date.

We have projected the results of the August 1, 2015 actuarial valuations of the OPEB Plan for US GAAP financial reporting purposes forward to 2016. The membership data is as at August 1, 2015 and we have not updated the membership data to reflect demographic changes since that date.

The purpose of these projections is to estimate EGDI's accrual costs in 2017.

As of January 1, 2016, Enbridge has chosen to implement a split rate approach for purposes of determining the benefit obligations and service cost as well as a spot rate approach for the calculation of interest on these items in the determination of the net periodic benefit cost. Separate discount rates are determined for the benefit obligations and service cost. Interest on benefit obligations, for purposes of determining the interest cost, and the interest on the service cost are calculated by applying interest to the present value of the associated payment. Additional details on this method can be found in the December 31, 2015 disclosure reports.

Under US GAAP, with the exception of the discount rate, assumptions are selected by Enbridge and are to be "management's best estimates". The discount rate must be chosen by reference to the market yields on high quality corporate bonds with cash flows similar to the aggregate cash flows of the pension plans. We have used the same assumptions as were used for the 2015 year-end disclosures under US GAAP, except we updated the discount rate to reflect market conditions at May 31, 2016 as follows:

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Assumption	Current Assumption – As at May 31, 2016	Prior Assumption – As at December 31, 2015
Discount rate for benefit obligation determination	3.90%	4.20%
Discount rate for current service cost determination	4.00%	4.30%

As noted above, the interest on benefit obligations, for purposes of determining the interest cost, and the interest on the service cost are calculated by applying interest to the present value of the payment expected at each payment date. For this purpose, interest is determined using the same spot rates determined at May 31, 2016 used to determine the present value of the associated payment.

Actual assumptions to be used at December 31, 2016 will be reviewed in the final quarter of 2016 and early 2017 by Enbridge and may be different from the assumptions used for these projections.

Except for the discount rate, all other assumptions, policies, methods and plan provisions are summarized in our ASC 715 (US GAAP) Actuarial Valuation Report as at December 31, 2015 Consolidated Total for All Plans Enbridge Gas Distribution Inc. dated February 2016 (“EGD Pension Report”), our ASC 715 (US GAAP) Actuarial Valuation Report as at December 31, 2015 Consolidated Total for All Plans Enbridge Inc. and Affiliates dated February 2016 (“EI Pension Report”), and our ASC 715 (US GAAP) Actuarial Valuation Report as at December 31, 2015 for Enbridge Gas Distribution Inc. Non-Pension Post Retirement Benefit Plan dated February 2016 (“OPEB Report”).

The market value of assets is used to determine pension costs. For the purposes of these estimates, we have relied on actual asset experience as reported by CIBC Mellon in the monthly unaudited financial statements obtained from their online reporting tool Workbench.

For the EGD RPP, SERP, and SSERP, the actual market value of assets as at May 31, 2016 was extrapolated to December 31, 2016 using:

- Contributions in accordance with minimum funding requirements and our understanding of Enbridge’s funding policy for 2016;
- Assumed benefit payments based on membership data at December 31, 2015; and
- Expected returns based on a net median long-term expected return assumption (5.70% annually for the EGD RPP and 3.20% annually for the SERP and SSERP).

For the EI RPP and SPP, the market value of assets as at May 31, 2016 was extrapolated to December 31, 2016 using:

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- Contributions in accordance with minimum funding requirements and our understanding of Enbridge's funding policy for 2016;
- Assumed benefit payments based on projections summarized in the EI Pension Report; and
- Expected returns to December 31, 2016 based on a net median long-term expected return assumption (6.32% annually for the EI RPP and 4.43% annually for the SPP).

As directed by you, we have reflected the economic conditions as at May 31, 2016.

Basis of Funding Projections

The EGD RPP consists of a defined benefit ("DB") provision and a defined contribution ("DC") provision. Minimum required cash funding to the DB component is determined based on actuarial valuations filed with the Financial Services Commission of Ontario ("FSCO") and the Canada Revenue Agency ("CRA"). Valuations may be filed at the plan sponsor's discretion, but must be filed at least once every three years. An actuarial valuation of the EGD RPP was filed with FSCO and the CRA as at December 31, 2013 (the "2013 Valuation"). Contributions to the EGD RPP by EGDI and the other participating employers must be made in accordance with the 2013 Valuation until a new valuation is filed with the regulators (but no later than as at December 31, 2016). As established in the 2013 Valuation, the going concern excess may be applied to reduce the employer contribution requirements in 2015 and 2016. EGDI has elected to contribute only the DC current service cost and is expected to contribute approximately $329,000 to the DB current service cost in 2016. Estimated 2017 EGD RPP contributions have been determined by extrapolating the December 31, 2015 actuarial funding valuation to December 31, 2016, and calculating the minimum contribution requirements that would result.

The SERP and SSERP are closed supplemental arrangements sponsored by EGDI and are relatively small compared to the EGD RPP. Contributions are determined annually in accordance with the plans' funding policies. 2017 SERP contributions were determined by extrapolating the December 31, 2015 actuarial funding valuation to December 31, 2016. 2017 SSERP contributions are assumed to be nil.

The EGD RPP and SERP funding extrapolations are based on membership data as at December 31, 2015 and the same methods and policies as the December 31, 2015 actuarial funding valuations as described in our Preliminary Valuation results as of December 31, 2015 presentation dated April 8, 2016 (the "2015 EGD Presentation"). The going concern liabilities are based on the same assumptions as were used at December 31, 2015. The EGD RPP solvency and SERP hypothetical wind-up liabilities are based on the same assumptions as were used at December 31, 2015, except we have updated the interest rates to reflect market conditions at May 31, 2016 as summarized in the following table:

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Assumption	Current Assumption – As at May 31, 2016	Prior Assumption – As at December 31, 2015
Non-indexed interest rates		
Benefits settled through lump sum	2.10% for 10 years; 3.40% thereafter	2.10% for 10 years; 3.70% thereafter
Benefits settled through annuity purchase	3.06%	3.08%
Indexed interest rates (55% indexed)		
Benefits settled through lump sum	1.60% for 10 years; 2.30% thereafter	1.70% for 10 years; 2.70% thereafter

For the purposes of determining the funding position, EGD RPP and SERP assets were extrapolated using the same methods described in *Basis of Accounting Projections*.

The SPP is a supplemental arrangement. Contributions are determined in accordance with the funding policy annually. An actuarial valuation of the SPP was conducted as at December 31, 2015 and is the basis for cash funding during 2016. Recently, the Alberta government increased the highest marginal personal tax rate to 48%, which will increase contributions in 2017. If the increased marginal tax rate had been reflected at December 31, 2015, EGDI's contribution would have increased by approximately $193,000. The estimated 2017 cash contribution in Appendix B is assumed to be the same as the 2016 contribution if the impact of the higher marginal tax rate had been reflected.

The EI RPP consists of a defined benefit ("DB") provision and a defined contribution ("DC") provision. Minimum required cash funding to the DB component is determined based on actuarial valuations filed annually with the Office for the Superintendent of Financial Institutions ("OSFI") and the Canada Revenue Agency ("CRA"). An actuarial valuation of the EI RPP was conducted as at December 31, 2015 and will be filed with OSFI and the CRA. We have assumed that minimum funding contributions in 2017 will not change from those determined in the actuarial valuation of the EI RPP conducted as at December 31, 2015.

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The OPEB Plan is a DB plan. The non-pension post retirement benefits are funded on a pay-as-you-go basis. The company funds on a cash basis as benefits are paid. No assets have been segregated and restricted to provide the non-pension post retirement benefits. Projected contributions are equivalent to the expected benefits to be paid, based on the data and assumptions outlined in the OPEB Report.

We trust that this letter contains all information you require for filing with the OEB. Please call if you have any additional questions or requests.

Sincerely,

Benedict O. Ukonga, FSA, FCIA
Principal
For pension plans

Isabelle Fournier, FSA, FCIA
Principal
For the non-pension post-retirement benefits plan

Copy:
Ryan Stelmaschuk, Enbridge Inc.
Joe De Dominicis, Mercer
Scott Thompson, Mercer

Enclosure

I:\retire\enbridge\2015\special projects\egd regulatory projections\deliverables\egdi 2016 estimated pension expense and contributions letter - final.docx

APPENDIX A

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Enbridge Gas Distribution Inc.

EGDI 2017 US GAAP Pension and OPEB Expense Projections

Pension and Non Pension Benefit Expense - US GAAP ($Millions) - Enbridge Gas Distribution Inc.'s Share Only

EGDI Only Portion of EGD RPP

Year	DC Current Service Cost	DB Current Service Cost	Interest Cost	Expected Return on Assets	Amortization of net actuarial loss (gain)	Amortization of Prior Service Cost	P&L Charge (Credit)
2017	0.85	31.36	32.08	-60.78	14.84	-	18.35

EGDI Only Portion of EI RPP

Year	Current Service Cost	Interest Cost	Expected Return on Assets	Amortization of net actuarial loss (gain)	Amortization of Prior Service Cost	P&L Charge (Credit)
2017	-	0.21	-0.5	0.11	-	-0.18

EGDI Only Portion of EI SPP (excluding CGT)

Year	Current Service Cost	Interest Cost	Expected Return on Assets	Amortization of net actuarial loss (gain)	Amortization of Prior Service Cost	P&L Charge (Credit)
2017	1.63	0.64	-1.11	0.35	-	1.51

SERP

Year	Current Service Cost	Interest Cost	Expected Return on Assets	Amortization of net actuarial loss (gain)	Amortization of Prior Service Cost	P&L Charge (Credit)
2017	-	0.43	-0.52	0.13	-	0.04

SSERP

Year	Current Service Cost	Interest Cost	Expected Return on Assets	Amortization of net actuarial loss (gain)	Amortization of Prior Service Cost	P&L Charge (Credit)
2017	-	0.10	-0.25	0	-	-0.15

EGDI Only Portion of OPEB Plan

Year	Current Service Cost	Interest Cost	Expected Return on Assets	Amortization of net actuarial loss (gain)	Amortization of Prior Service Cost	P&L Charge (Credit)
2017	1.42	3.54	-	0.10	0.10	5.16

Total Enbridge Gas Distribution Inc.

Year	DC Current Service Cost	Current Service Cost	Interest Cost	Expected Return on Assets	Amortization of net actuarial loss (gain)	Amortization of Prior Service Cost	P&L Charge (Credit)
2017	0.85	34.41	37.00	-63.16	15.53	0.10	24.73

APPENDIX B

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Enbridge Gas Distribution Inc.

EGDI 2017 Cash Contribution Projections

Enbridge Gas Distribution Inc.'s Share of Funding ($Millions)

EGDI Only Portion of EGD RPP

Year	DC Current Service Cost	DB Current Service Cost	Special Payments*	Total Annual Employer Contributions
2017	0.85	21.67	21.42	43.94

EGDI Only Portion of EI RPP

Year	Current Service Cost	Special Payments**	Total Annual Employer Contributions
2017	-	0.03	0.03

EGDI Only Portion of EI SPP (including CGT)

Year	Current Service Cost	Special Payments**	Total Annual Employer Contributions
2017	1.23	1.43	2.66

SERP

Year	Current Service Cost	Special Payments**	Total Annual Employer Contributions
2017	-	0.26	0.26

SSERP

Year	Current Service Cost	Special Payments**	Total Annual Employer Contributions
2017	-	-	-

EGDI Only Portion of OPEB Plan

Year	Total Annual Employer Contributions
2017	4.54

Total Enbridge Gas Distribution Inc.

Year	Total Annual Employer Contributions
2017	51.43

* Assumes that Enbridge elects to fund the projected solvency deficiency in 2017
** Special payments are calculated and updated annually.

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Appendix C

Important Notices

Mercer has prepared this letter exclusively for EGDI for submitting to the OEB. This letter may not be used or relied upon by any other party or for any other purpose; Mercer is not responsible for the consequences of any unauthorized use.

The results shown in this letter are derived from funding and accounting valuation results shown in the following actuarial valuation reports or results presentations (the "2015 Reports"):

- The Preliminary Actuarial Valuation as at December 31, 2015 for the EGD RPP (the "2015 EGD RPP Funding Report")[1];
- The ASC 715 (US GAAP) Actuarial Valuation Report as at December 31, 2015 Consolidated Total for All Plans Enbridge Inc. and Affiliates (the "2015 EI RPP and SPP Accounting Report");
- Preliminary Valuation results as of December 31, 2015 presentation dated April 8, 2016, for the SERP and SSERP (the "2015 EGD Presentation");
- The ASC 715 (US GAAP) Actuarial Valuation Report as at December 31, 2015 for Enbridge Gas Distribution Inc. Non-Pension Post Retirement Benefit Plan (the "2015 OPEB Accounting Report").

The results shown in this letter are subject to the same Important Notices and qualifications described in the 2015 Reports except as specifically noted in this letter. The 2015 Reports are incorporated by reference into this letter and are essential to understanding the results. If you do not have copies of the 2015 Reports, please let us know immediately.

The accounting projections for the purposes of determining 2017 accrual costs are based on the same actuarial assumptions used in the 2015 Reports except as noted in the *Basis of Accounting Projections* section of this letter. The funding projections for the purposes of determining 2017 cash costs, where applicable, are based on the same actuarial assumptions used in the 2015 Reports except as noted in the *Basis of Funding Projections* section of this letter.

[1] The 2015 EGD RPP Funding Report was being drafted at the time this letter was prepared.

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There were no changes to the actuarial methods used in the 2015 Reports.

Our extrapolation reflects a single scenario from a range of possibilities. However, the future is uncertain, and the plans' actual experience will likely differ from the assumptions utilized and the scenarios presented; these differences may be significant or material. This letter is presented at a particular point in time and should not be viewed as a prediction of the plans' future financial conditions or their ability to pay benefits in the future.

The results shown in this letter are based on the membership data used in the 2015 Reports with the following adjustment since December 31, 2015 for the EGD RPP, SERP and SSERP:

- Actual benefit payments to May 31, 2016 based on the CIBC Mellon monthly unaudited financial statements;
- Assumed benefit payments between June 1, 2015 and December 31, 2016 based on actual May contributions for the SERP and SSERP; and
- Assumed benefit payments between June 1, 2015 and December 31, 2016 based on projections summarized in the EGD Pension Report for the EGD RPP.

The results shown in this letter are based on plan provisions provided by the plan administrator. There were no changes made to the plan provisions since December 31, 2015.

Because actual plan experience will differ from the assumptions, decisions about benefit changes, investment policy, funding amounts, benefit security and/or benefit-related issues should be made only after careful consideration of alternative future financial conditions and scenarios and not solely on the basis of a valuation report or reports.

2017 UTILITY TAXABLE INCOME AND INCOME TAX EXPENSE

1. This evidence addresses the change in utility taxable income and income tax expense, excluding CIS and Customer Care impacts, and excluding any taxes on gross deficiency amounts, between the 2017 placeholder amounts (EB-2012-0459) and the 2017 Updated Forecast amounts presented within this proceeding. The calculation of the 2017 Updated Forecast utility taxable income and income tax, and the change from 2017 placeholder amounts is provided at Exhibit D1, Tab 6, Schedule 2.

2. The calculation of utility taxable income and income tax expense begins with utility income before income taxes. As seen in Line 1 of Exhibit D1, Tab 6, Schedule 2, utility income before income tax has increased by $24.4 million, from $326.0 million in the 2017 placeholder, to $350.4 million in the 2017 Updated Forecast. The increase is the net impact of updating revenue and cost elements which are subject to annual updates throughout Enbridge's customized incentive regulation term, as identified within Appendix E of the EB-2012-0459 Decision and Rate Order, as well as impacts resulting from adjustments made in accordance with the 2016 Rate Adjustment proceeding (EB-2015-0114) Board approved Settlement Agreement which required an allocation of base pressure gas and Lost and Unaccounted for gas ("LUF") to Unregulated Storage operations, as a result of the adoption of fully allocated costing for those items. Revenues have been updated to reflect the impact of the updated 2017 volume forecast and July 1, 2016 Board Approved rates, as detailed in the C series of exhibits. Gas costs and operation and maintenance costs have been updated to reflect impacts of the updated 2017 volume forecast (inclusive of the allocation of LUF to Unregulated Storage), the updated 2017 gas supply plan, July 1, 2016 Board Approved rates, pension and OPEB cost updates, DSM cost updates, and CIS and Customer Care cost updates

(in accordance with the EB-2011-0226 approved Settlement Agreement), as detailed in the D series of exhibits. Once updated revenues and costs were derived, updated CIS and Customer Care costs, which are subject to a separately approved recovery mechanism, were removed to allow taxes and a deficiency excluding CIS and Customer Care impacts to be calculated.

3. Having updated utility income before taxes, corresponding tax add back and deduction updates, related to the updated revenues and costs, must be made in order to determine utility taxable income. Updates to tax add backs and deducts are detailed in Rows 2 through 17 of Exhibit D1, Tab 6, Schedule 2. The pension and OPEB tax add back (Row 3) was updated in conjunction with the updated forecast accrual based cost included within operation and maintenance costs, and therefore utility income before taxes, while the tax deduct (Row 15) was updated to reflect the updated forecast cash based cost. Updated forecast pension and OPEB costs are found in Exhibit D1, Tab 5, Schedule 1. The tax deductions for "grossed up" part VI.1 tax (Row 10) and the amortization of share/debenture issue expenses (Row 11) have been updated in conjunction with updates to the preferred share and long-term debt components of capital structure, to reflect the impact of actual results and updated forecasts as identified in the E series of exhibits.

4. The net impact of updating utility income before tax, and tax add backs and deducts, is a $3.0 million increase in taxable income (Rows 18 and 19 of Exhibit D1, Tab 6, Schedule 2) and corresponding $0.9 million increase in income tax expense (Rows 22 to 24 of Exhibit D1, Tab 6, Schedule 2).

5. Utility income tax is then reduced by $1.0 million as a result of lower part VI.1 tax (Row 25 of Exhibit D1, Tab 6, Schedule 2), which similar to the deduction for

"grossed up" part VI.1 has been updated to reflect the updated preferred share cost component of capital structure.

6. The final update to utility income tax is to reflect an updated tax shield on interest expense, shown in Rows 27 to 31 of Exhibit D1, Tab 6, Schedule 2. The change in the interest tax shield is impacted by a higher net rate base value, offset by a lower return component of debt. The higher net rate base value results from the 2017 volumes, gas supply plan, pricing, and allocation of base pressure gas to Unregulated Storage updates, which are detailed in the B series of exhibits. The lower return component of debt results from updates which reflect the impact of actual debt issuances, as well as updated 2017 forecast issuances and cost rates, as identified in the E series of exhibits. The net impact is a $3.9 million reduction in the tax shield on interest expense.

7. The combined impact of all the above mentioned updates is a $3.8 million increase in the 2017 Updated Forecast utility income tax expense, excluding CIS and Customer Care impacts, and excluding any taxes on gross deficiency amounts, as shown on Row 32 of Exhibit D1, Tab 6, Schedule 2, and on Row 16, Column 4, of Exhibit F1, Tab 2, Schedule 1.

8. The Updated Forecast utility income tax expense does not include any potential impact associated with Cap and Trade greenhouse gas emissions requirements. Income tax impacts or requirements arising from Cap and Trade will be addressed in the proceeding that considers Enbridge's 2017 Compliance Plan for Cap and Trade obligations and/or recorded in the 2017 GGEIDA for future disposition.

CALCULATION OF UTILITY TAXABLE INCOME AND INCOME TAX EXPENSE
2017 UPDATED FORECAST (EXCLUDING CIS & CUSTOMER CARE)

Line No.		Col. 1 EB-2012-0459 2017 Utility Placeholder Tax ($Millions)	Col. 2 2017 CIR Update Adjustments ($Millions)	Col. 3 2017 Updated Forecast Utility Tax ($Millions)
1.	Utility income before income taxes	326.0	24.4	350.4
	Add			
2.	Depreciation and amortization	285.0	-	285.0
3.	Accrual based pension and OPEB costs	28.5	(3.8)	24.7
4.	Other non-deductible items	1.0	-	1.0
5.	Total Add Back	314.5	(3.8)	310.7
6.	Sub total	640.5	20.6	661.1
	Deduct			
7.	Capital cost allowance - Federal	298.2	-	298.2
8.	Capital cost allowance - Provincial	298.2	-	298.2
9.	Items capitalized for regulatory purposes	46.6	-	46.6
10.	Deduction for "grossed up" Part VI.1 tax	5.6	(2.5)	3.1
11.	Amortization of share/debenture issue expense	3.9	0.9	4.8
12.	Amortization of cumulative eligible capital	4.8	-	4.8
13.	Amortization of C.D.E. and C.O.G.P.E	0.1	-	0.1
14.	Site restoration cost adjustment	77.5	-	77.5
15.	Cash based pension and OPEB costs	32.2	19.2	51.4
16.	Total Deduction - Federal	468.9	17.6	486.5
17.	Total Deduction - Provincial	468.9	17.6	486.5
18.	Taxable income - Federal	171.6	3.0	174.6
19.	Taxable income - Provincial	171.6	3.0	174.6
20.	Income tax rate - Federal	15.00%	0.00%	15.00%
21.	Income tax rate - Provincial	11.50%	0.00%	11.50%
22.	Income tax provision - Federal	25.7	0.5	26.2
23.	Income tax provision - Provincial	19.7	0.4	20.1
24.	Income tax provision - combined	45.4	0.9	46.3
25.	Part V1.1 tax	1.9	(1.0)	0.9
26.	Total taxes excluding tax shield on interest expense	47.3	(0.1)	47.2
	Tax shield on interest expense			
27.	Rate base	5,928.9	75.5	6,004.4
28.	Return component of debt	3.30%	-0.29%	3.01%
29.	Interest expense	195.5	(14.8)	180.7
30.	Combined tax rate	26.50%	0.00%	26.50%
31.	Income tax credit	(51.8)	3.9	(47.9)
32.	Total income taxes	(4.5)	3.8	(0.7)

Witness: R. Small

DEFERRAL AND VARIANCE ACCOUNTS

2016 Approved Deferral and Variance Accounts

1. The following list identifies Enbridge's 2016 Board Approved deferral and variance accounts ("DA" and "VA") which were approved within Enbridge's 2016 Rate Adjustment proceeding EB-2015-0114, Enbridge's 2015 - 2020 Multi-Year DSM Plan Proceeding EB-2015-0049, and by Board letter dated February 9, 2016, notifying all regulated entities of revisions to the Ontario Energy Board cost assessment model. For the 2016 deferral and variance accounts approved and listed below, Enbridge will file a separate application(s) requesting a process for the review and proposed clearance of the accounts as soon as feasibly possible following the public release of its fiscal 2016 year-end financial results (around April 2017).

2016 Purchased Gas Variance Account ("PGVA"),
2016 Unabsorbed Demand Cost Deferral Account ("UDCDA"),
2016 Transactional Services Deferral Account ("TSDA"),
2016 Unaccounted for Gas Variance Account ("UAFVA"),
2016 Storage and Transportation Deferral Account ("S&TDA")
2016 Deferred Rebate Account ("DRA"),
2016 Customer Care CIS Rate Smoothing Deferral Account ("CCCISRSDA"),
2016 Average Use True-Up Variance Account ("AUTUVA"),
2016 Manufactured Gas Plant Deferral Account ("MGPDA"),
2016 Gas Distribution Access Rule Impact Deferral Account ("GDARIDA"),
2016 Electric Program Earnings Sharing Deferral Account ("EPESDA"),
2016 Open Bill Revenue Variance Account ("OBRVA"),
2016 Ex-Franchise Third Party Billing Services Deferral Account ("EFTPBSDA"),
2016 Post-Retirement True-Up Variance Account (PTUVA"),

2016 Transition Impact of Accounting Change Deferral Account (“TIACDA”),
2016 Demand Side Management Variance Account (“DSMVA”),
2016 Lost Revenue Adjustment Mechanism Variance Account (“LRAM”),
2016 Demand Side Management Incentive Deferral Account (“DSMIDA”),
2016 Earnings Sharing Mechanism Deferral Account (“ESMDA”),
2016 Customer Care Services Procurement Deferral Account (“CCSPDA”),
2016 Greenhouse Gas Emissions Impact Deferral Account (“GGEIDA”),
2016 Constant Dollar Net Salvage Adjustment Deferral Account (“CDNSADA”),
2016 Dawn Access Costs Deferral Account (“DACDA”),
2016 Credit Final Bill Deferral Account (“CFBDA”),
2016 Greater Toronto Area Incremental Transmission Capital Revenue Requirement Deferral Account (“GTAITCRRDA”),
2016 Rate 332 Deferral Account (“R332DA”),
2016 Demand Side Management Cost-Efficiency Incentive Deferral Account (“DSMCEIDA”),
2016 OEB Cost Assessment Variance Account (“OEBCAVA”).

<u>2017 Approved and Proposed Deferral and Variance Accounts</u>

2. Within the EB-2012-0459 Decision, the Board approved the use of a number of deferral and variance accounts for all or a portion of the 2014 through 2018 customized incentive regulation term. The following list identifies the accounts which were approved for 2017.

2017 Purchased Gas Variance Account (“PGVA”),
2017 Transactional Services Deferral Account (“TSDA”),
2017 Unaccounted for Gas Variance Account (“UAFVA”),
2017 Storage and Transportation Deferral Account (“S&TDA”),
2017 Deferred Rebate Account (“DRA”),

2017 Customer Care CIS Rate Smoothing Deferral Account ("CCCISRSDA"),
2017 Average Use True-Up Variance Account ("AUTUVA"),
2017 Greenhouse Gas Emissions Impact Deferral Account ("GGEIDA"),
2017 Earnings Sharing Mechanism Deferral Account ("ESMDA")
2017 Manufactured Gas Plant Deferral Account ("MGPDA"),
2017 Gas Distribution Access Rule Impact Deferral Account ("GDARIDA"),
2017 Electric Program Earnings Sharing Deferral Account ("EPESDA"),
2017 Open Bill Revenue Variance Account ("OBRVA"),
2017 Ex-Franchise Third Party Billing Services Deferral Account ("EFTPBSDA"),
2017 Constant Dollar Net Salvage Adjustment Deferral Account ("CDNSADA"),
2017 Transition Impact of Accounting Changes Deferral Account ("TIACDA"),
2017 Post-Retirement True-Up Variance Account ("PTUVA"),
2017 Greater Toronto Area Incremental Transmission Capital Revenue Requirement Deferral Account ("GTAITCRRDA"),
2017 Demand Side Management Variance Account ("DSMVA"),
2017 Lost Revenue Adjustment Mechanism Variance Account ("LRAM"),
2017 Demand Side Management Incentive Deferral Account ("DSMIDA"),
2017 Relocation Mains Variance Account ("RLMVA"),
2017 Replacement Mains Variance Account ("RPMVA").

3. Within the EB-2014-0323 and EB-2015-0049 proceedings, and by Board letter dated February 9, 2016, notifying all regulated entities of revisions to the Ontario Energy Board cost assessment model, the Board also approved the establishment of the following accounts for use during 2017:

2017 Dawn Access Costs Deferral Account ("DACDA"),

2017 Demand Side Management Cost-Efficiency Incentive Deferral Account (DSMCEIDA"),
2017 OEB Cost Assessment Variance Account ("OEBCAVA").

4. In addition to the accounts which have been previously approved, as part of this proceeding, the Company is also requesting that the following accounts be established for use during 2017.

2017 Customer Care Services Procurement Deferral Account ("CCSPDA"),
2017 Rate 332 Deferral Account ("R332DA").

5. The criteria adopted by the Company in determining to request the establishment of the additional deferral accounts above included the following considerations:
- whether the account, or a similar account, has previously been approved;
- the materiality of the amount at risk (revenue or expense);
- protection of the ratepayer or the shareholder from benefitting at the expense of the other party related to a variance in the forecast amount;
- the level of uncertainty associated with a forecast of the amount at risk; and
- the aspect of control - are the underlying circumstances beyond the Company's ability to control.

6. Following the end of 2017, Enbridge will file a separate application(s) requesting a process for the review and proposed clearance of the 2017 deferral and variance accounts as soon as feasibly possible following the public release of its fiscal year-end financial results (around April of 2018).

Descriptions of Accounts

2017 Purchased Gas Variance Account ("2017 PGVA")

7. The purpose of the 2017 PGVA is to record the effect of price variances between actual 2017 gas purchase prices and the forecast prices that underpin the revenue rates to be charged in 2017. Without this deferral account, the ratepayers and the Company are exposed to the risk of purchased gas price variances, which could unduly penalize or benefit one party at the benefit or expense of the other. Lower than forecast gas purchase prices would result in an over recovery from the customers and higher prices would result in an under recovery to the Company. This deferral account ensures that such effects are eliminated.

2017 PGVA Methodology

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

9. The fixed cost component of the TransCanada firm service transportation costs (i.e., Transportation Demand Charge) is included in the determination of the reference price. However, any demand charges relating to unutilized transportation capacity, either forecast or actual, are excluded.

This treatment of forecast and actual Transportation Demand Charges for unutilized transportation capacity is consistent with the Board's concerns that these amounts be excluded from the PGVA.

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

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

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

13. For the period January 1 to December 31, 2017, expenditures related to TCPL's Storage Transportation Services, including balancing fees related to TCPL's Limited Balancing Agreement, will be recorded in the 2017 PGVA. The 2017 PGVA will also record amounts related to a Limited Balancing Agreement with Union Gas.

14. The PGVA will record adjustments related to Transactional Services activities which are designed to record the impact of direct and avoided costs between the PGVA and the TSDA. These adjustments are required to ensure appropriate allocation of costs and benefits to the underlying transactions and appropriate recording of amounts in the 2017 PGVA and 2017 TSDA for purposes of deferral account dispositions.

15. In addition, the 2017 PGVA will record the amounts related to unforecast penalty revenues received from interruptible customers who do not comply with the Company's curtailment requirements, unauthorized overrun gas revenues, the use of electronic bulletin boards, and the unforecast Unabsorbed Demand Charge ("UDC") that arises as a consequence of the Company voluntarily leaving transportation capacity unutilized in order to gain a net benefit for the customer by purchasing lower priced unforecast discretionary delivered supplies.

16. The 2017 PGVA will also record an inventory valuation adjustment every time a recalculated "Utility Price" or PGVA Reference Price comes into effect at the beginning of a quarter within the fiscal year. The adjustment consists of the storage inventory valuation adjustment necessary to price actual opening inventory volumes at a rate equal to the Board approved quarterly PGVA reference price.

17. The 2017 PGVA will also record any refund/collection associated with Board approved Gas Cost Adjustment Riders.

18. The Company will record, at the time a Banked Gas Account Balance is purchased from a customer, the difference in the amount payable to the customer and the amount included in the PGVA (Transportation Service Rider A). This

amount would be credited to a sub-account of the PGVA. In the event the Company incurs unforecast UDC costs as a result of having to purchase Banked Gas Account Balances then the amount in such sub-account will be used to offset corresponding UDC costs. All amounts remaining in this sub-account, after offsetting these UDC costs, will be rolled up into the PGVA.

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

20. Simple interest is to be calculated on the opening monthly balance of the 2017 PGVA using the Board Approved EB-2006-0117 interest rate methodology.

<u>2017 Transactional Services Deferral Account ("2017 TSDA")</u>

21. The purpose of the 2017 TSDA is to record the incremental ratepayer share of net revenue from transportation and storage related Transactional Services, to be shared 90/10 between Enbridge's ratepayers and shareholders.

22. In the event that the ratepayer share of 2017 TS net revenue exceeds $12.0 million, then such amounts over $12.0 million will be credited to the TSDA. In the event that the ratepayer share of 2017 TS net revenue is less than $12.0 million, then Enbridge will be credited with the difference between the actual ratepayer share of 2017 TS net revenue and $12.0 million, which would be reflected as a debit in the TSDA.

23. Net revenue is defined as gross revenues for providing these services less any direct incremental costs incurred, plus, any avoided costs. Direct incremental costs represent those direct costs incurred as a result of a transactional service activity and avoided costs are those costs that have been avoided as a result of a transactional service activity. Typical direct incremental costs and avoided costs would include transportation costs, fuel costs, charges for name changes, and re-direct charges.

24. Simple interest is to be calculated on the opening monthly balance of the 2017 TSDA using the Board Approved EB-2006-0117 interest rate methodology. The balance of this account, together with carrying charges, will be disposed of in a manner designated by the Board in a future rate hearing.

2017 Unaccounted for Gas Variance Account ("2017 UAFVA")

25. The purpose of the 2017 UAFVA is to record the cost of gas that is associated with volumetric variances between the actual volume of Unaccounted for Gas ("UAF") and the 2017 Board approved UAF volumetric forecast. The 2017 UAF volumetric forecast is described at Exhibit D1, Tab 2, Schedule 3.

26. The gas costs associated with the UAF variance will be calculated at the end of calendar 2017 based on the estimated volumetric variance between the 2017 Board approved level of UAF and the estimate of the 2017 actual UAF. An adjustment will be made to the UAFVA in the subsequent year to record any differences between the estimated UAF and actual UAF.

27. The UAF annual variance will be allocated on a monthly basis in proportion to actual sales and costed at the monthly PGVA reference price.

28. Where there are recoveries of gas loss amounts invoiced as part of 3rd party damages, the gas loss amounts will be removed from the UAFVA balance.

29. Carrying costs for the UAFVA will be calculated using the Board Approved EB-2006-0117 interest rate methodology. The balance of the UAFVA, together with the carrying charges, will be disposed of in a manner designated by the Board in a future rate hearing.

2017 Storage and Transportation Deferral Account ("2017 S&TDA")

30. The purpose of the 2017 S&TDA is to record the difference between the forecast of Storage and Transportation rates (both cost of service and market based pricing) included in the Company's approved rates and the final Storage and Transportation rates (both cost of service and market based pricing) incurred by the Company. It will also be used to record variances between the forecast Storage and Transportation rebate programs and the final rebates received by the Company. The accounting treatment for the S&TDA is in line with that established for the 2008 S&TDA, which recognized that storage and transportation services may be provided to the Company by suppliers other than Union Gas and at market based rates.

31. The 2017 S&TDA will also record the variance between the forecast Storage and Transportation demand levels and the actual Storage and Transportation demand levels. In addition, this account will be used to record amounts related to deferral account dispositions received or invoiced from Storage and Transportation suppliers.

32. The 2017 S&TDA will also record the variance between the forecasted commodity cost for fuel and the updated QRAM Reference Price.

33. Simple interest is to be calculated on the opening monthly balance of the 2017 S&TDA using the Board Approved EB-2006-0117 interest rate methodology. The balance of this account, together with carrying charges, will be disposed of in a manner designated by the Board in a future rate hearing.

<u>2017 Deferred Rebate Account ("2017 DRA")</u>

34. The purpose of the 2017 DRA is to record any amounts payable to, or receivable from, customers of the Company as a result of the clearing of deferral and variance accounts authorized by the Board which remain outstanding due to the Company's inability to locate such customers.

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

<u>2017 Customer Care CIS Rate Smoothing Deferral Account ("2017 CCCISRSDA")</u>

36. The purpose of the 2017 CCCISRSDA is to capture the difference between the Board approved customer care and CIS costs versus the smoothed amount to be collected in revenues as approved by the Board in the EB-2011-0226 CIS Customer Care Settlement Agreement and proceeding. The amount to be debited or credited to the deferral account, for each of 2013 through 2018 years, will be calculated by multiplying the difference in Board approved cost per customer and smoothed cost per customer by the updated customer forecast for that year. The balances in the accounts will not be cleared during the 2013 through 2018 period. The cumulative balance will build up during the years 2013 to 2015 when the Board approved cost per customer exceeds the smoothed cost

per customer being collected in rates, and then will be drawn down during the years 2016 to 2018 when the Board approved cost per customer is lower than the smoothed cost per customer being collected in rates. After 2018, any remaining balance in the account is to be cleared along with the clearance of other deferral and variance accounts.

37. As determined in the EB-2011-0226 Settlement Agreement, interest is to be calculated on the balance of this account at a fixed annual rate of 1.47%, and will not change during the period the deferral account is allowed to continue through 2018. The interest carrying charges will be disposed of annually at the same time of clearance of all other deferral and variance accounts.

<u>2017 Average Use True-Up Variance Account ("2017 AUTUVA")</u>

38. The purpose of the 2017 AUTUVA is to record ("true-up") the revenue impact, exclusive of gas costs, of the difference between the forecast of average use per customer, for general service rate classes (Rate 1 and Rate 6), embedded in the volume forecast that underpins Rates 1 and 6 (see Exhibit C1, Tab 2, Schedule 1) and the actual weather normalized average use experienced during the year. The calculation of the volume variance between forecast average use and actual normalized average use will exclude the volumetric impact of Demand Side Management programs in that year. The revenue impact will be calculated using a unit rate determined in the same manner as for the derivation of the Lost Revenue Adjustment Mechanism ("LRAM"), extended by the average use volume variance per customer and the number of customers.

39. Simple interest is to be calculated on the opening monthly balance of this account using the Board approved EB-2006-0117 interest rate methodology. The balance

of this account, together with carrying charges, will be disposed of in a manner designated by the Board in a future rate hearing.

<u>2017 Greenhouse Gas Emissions Impact Deferral Account ("2017 GGEIDA")</u>

40. In EB-2012-0459 (the 2014 through 2018 rate application), the Board approved the GGEIDA. As stated in the Board's Decision with Reasons (p. 70):

> [t]he GGEIDA would be used to record the impacts of provincial and federal regulations related to greenhouse gas emission requirements along with the impacts resulting from the sale of, or other dealings in, earned carbon dioxide offset credits.

41. The Ontario Government has passed the *The Climate Change Mitigation and Low-carbon Economy Act,* 2016 ("Climate Change Act") and the related Cap and Trade Regulation which outline Ontario's cap and trade program and the new legal obligations required of Enbridge in support of the Government of Ontario's Greenhouse Gas ("GHG") reduction initiative. The cap and trade program will begin on January 1, 2017.

42. The OEB released its Regulatory Framework for the Assessment of Costs of Natural Gas Utilities' Cap and Trade Activities – Report of the Board on September 26, 2016 (EB-2015-0363). Within the attached cover letter to the Report, the Board indicated that each of the gas distribution utilities are expected to file Cap and Trade Compliance Plans by November 15, 2016. Enbridge will file evidence within its Compliance Plan application requesting appropriate deferral and variance account treatments for costs and revenues associated with Cap and Trade. If there is no approval prior to January 1, 2017 for new or amended deferral and variance accounts related to Cap and Trade costs and revenues, then Enbridge will use the GGEIDA to record all impacts of Cap and Trade until such time as the Board orders otherwise.

2017 Earnings Sharing Mechanism Deferral Account (“2017 ESMDA”)

43. The purpose of the 2017 ESMDA is to record the ratepayer share of utility earnings that result from the application of the Earnings Sharing Mechanism (“ESM”). If the 2017 actual utility Return On Equity (“ROE”), calculated on a weather normalized basis, exceeds the Board's approved formula ROE utilized in determining 2017 Allowed Revenues, the resultant amount will be shared equally (i.e., 50/50) between the Company’s ratepayers and shareholders. The calculation of a utility return for earnings sharing determination purposes, will include all revenues that would otherwise be included in earnings and only those expenses (whether operating or capital) that would otherwise be allowable deductions from earnings as within a cost of service application. In addition, the following are examples of shareholder incentives and other amounts which are outside of the ambit of the ESM: amounts related to Demand Side Management incentives (“DSMIDA”) and Lost Revenue Adjustment Mechanism (“LRAM”), amounts related to Transactional Services incentives, amounts related to Open Bill program incentives, and amounts related to Electric Program Earnings Sharing incentives (“EPESDA”). The ESM is non-symmetrical, such that ratepayers will not be responsible for sharing any level of under-earnings.

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

2017 Manufactured Gas Plant Deferral Account ("2017 MGPDA")

45. The purpose of the 2017 MGPDA is to capture all costs incurred in managing and resolving issues related to the Company's Manufactured Gas Plant ("MGP") legacy operations. Costs charged to the account could include, but are not limited to:

- Responding to all enquiries, demands and court actions relating to former MGP sites;
- All oral and written communications with existing and former third party liability and property insurers of the Company;
- Conducting all necessary historical research and reviews to facilitate the Company's responses to all enquiries, demands, court actions and communications with claimants, third parties and insurers;
- Engaging appropriate experts (for example, environmental, insurance archivists, engineers, etc.) for the purposes of evaluating any alleged contamination that may have resulted from former MGP operations and providing advice regarding the appropriate steps to remediate/contain/ monitor such contamination, if any;
- Engaging legal counsel to respond to all demands and court actions by claimants, and to take appropriate steps in relation to the Company's existing and former third party liability and property insurers; and
- Undertaking appropriate research into the regulatory treatment of costs resulting from former MGP operations in the United States.

46. The MGPDA would also be used to record any amounts which are payable to any claimant following settlement or trial, including any damages, interest, costs and disbursements and any recoveries from insurers or third parties.

47. In the event that Enbridge does not request clearance of amounts recorded in the 2016 MGPDA at the same time as other 2016 accounts are requested for clearance, then the balance in the account will be transferred to the 2017 MGPDA.

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

<u>2017 Gas Distribution Access Rule Impact Deferral Account (“2017 GDARIDA”)</u>

49. The purpose of the 2017 GDARIDA is to record all incremental unbudgeted capital and operating impacts associated with the development, implementation, and operation of the Gas Distribution Access Rule (“GDAR”) and any ongoing amendments to the rule. Such impacts would include, but not be limited to, market restructuring oriented customer education and communication programs, legal or expert advice required, operating costs or revenue changes in relation to the establishment of contractual agreements and developing revised business processes and related computer hardware and software required to meet the requirements of the GDAR.

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

<u>2017 Electric Program Earnings Sharing Deferral Account ("2017 EPESDA")</u>

51. The purpose of the 2017 EPESDA is to track and account for the ratepayer share of all net revenues generated by DSM services provided for electric CDM activities. The ratepayer share is 50% of net revenues, using fully allocated costs, as was determined in DSM guidelines proceeding EB-2008-0346.

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

<u>2017 Open Bill Revenue Variance Account ("2017 OBRVA")</u>

53. The purpose of the OBRVA is to track and record the ratepayer share of net revenue for Open Bill Services. The account allows for net annual revenue amounts in excess of $7.389 million to be shared 50/50 with ratepayers, and allows for a credit to Enbridge in the event that net annual revenues are less than $4.889 million, equal to the shortfall between actual net revenues and $4.889 million. The net revenue amounts will be determined in accordance with the EB-2009-0043 Board Approved Open Bill Access Settlement Proposal dated October 15, 2009, with updated fees and costs as determined in the EB-2013-0099 proceeding.

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

2017 Ex-Franchise Third Party Billing Services Deferral Account ("2017 EFTPBSDA")

55. The purpose of the 2017 EFTPBSDA is to record and track the ratepayer portion of revenues, net of incremental costs, generated from third party billing services provided to ex-franchise parties. The net revenue is to be shared on a 50/50 basis with ratepayers. The net revenue amounts will be determined in accordance with the EB-2009-0043 Board Approved Open Bill Access Settlement Proposal dated October 15, 2009, with updated Fees and Costs as determined in the EB-2013-0099 proceeding.

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

2017 Constant Dollar Net Salvage Adjustment Deferral Account ("2017 CDNSADA")

57. The purpose of the 2017 CDNSADA is to record and clear the 2017 credit to ratepayers that results from the adoption of the Constant Dollar Net Salvage ("CDNS") approach for determining the net salvage percentages to be included within Enbridge's depreciation rates.

58. As a result of the adoption of the CDNS approach, the Company has an estimated excess net salvage reserve when compared to the reserve which accumulated while the Company employed the Traditional Method for determining net salvage percentages. The net salvage reserve is recorded within a liability account which, for utility rate base determination purposes, is accounted for as an offset against specific property, plant and equipment asset category balances as part of accumulated depreciation. Within Enbridge's EB-2012-0459 decision (2014 to 2018 Rate Application), the Board ordered the refund to ratepayers of

$379.8 million in net salvage reserve over the 2014 to 2018 period, through Rate Rider D. The annual refund amounts are: 2014 - $96.8 million, 2015 - $90.4 million, 2016 - $83.9 million, 2017 - $77.5 million, and 2018 - $31.1 million.

59. On a monthly basis each year, the net salvage liability (or accumulated depreciation for utility rate base purposes) will be debited by the forecast monthly rider amount, with a corresponding credit recorded in the CDNSADA. Within the same month, the CDNSADA will be debited, with a corresponding credit to accounts receivable, for the actual amount refunded to customers through Rate Rider D.

60. In each year, the final balance in the account will be the cumulative variance between the amounts proposed for clearance and the actual amounts cleared. The balance will be transferred to the following year's CDNSADA, and at the end of 2018 any residual balance will be cleared in a post 2018 true up, ensuring the actual amount cleared is equivalent to the required $379.8 million. As such, the final balance in the 2016 CDNSA will be transferred to the 2017 CDNSA.

61. No interest is to be calculated on the balance in this account.

<u>2017 Transition Impact of Accounting Changes DA ("2017 TIACDA")</u>

62. The purpose of the 2017 TIACDA is to track and roll forward un-cleared amounts recorded in the 2016 TIACDA. In EB-2011-0354, the Board approved the recovery of Other Post Employment Benefit ("OPEB") costs, forecast to be $90 million at the end of 2012, over a 20 year period, commencing in 2013. The OPEB costs needed to be recognized as a result of Enbridge having to account for post-employment expenses on an accrual basis, upon transition to USGAAP for corporate reporting purposes in 2012. The use of USGAAP for regulatory

purposes was approved within the 2013 rate proceeding, EB-2011-0354. The final estimate of OPEB costs to be recovered over 20 years, which was recorded in the TIACDA at the end of 2012, was $88.7 million. The first, second, third, and fourth installments of $4.4 million each (1/20 of $88.7 million), were approved for recovery in EB-2013-0046, EB-2014-0195, EB-2015-0122, and EB-2016-0142. The balance in the account will continue to be drawn down and cleared to ratepayers by $4.4 million annually, with the un-cleared balance to be rolled forward to the subsequent year's TIACDA, until clearance is complete.

63. Interest is not applicable to the balance of this account.

<u>2017 Post-Retirement True-Up VA ("2017 PTUVA")</u>

64. The purpose of the 2017 PTUVA is to record the differences between forecast 2017 pension and post-employment benefit expenses of $24.7 million (see Exhibit D1, Tab 5, Schedule 1), and actual 2017 pension and post-employment benefit expenses (both determined on an accrual basis). The 2017 PTUVA will be cleared in a manner that will allow for all variances between $24.7 million and actual pension and OPEB expenses to be recorded and cleared, subject to the condition that any amounts in excess of $5 million (credit or debit) will be transferred into the following year's account, so that large variances can be cleared over time (smoothed). Under this approach, the maximum amount (debit or credit) that will be cleared from the 2017 PTUVA will be $5 million, and any remaining amounts will be transferred to the 2018 PTUVA for future clearance.

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

2017 Greater Toronto Area Incremental Transmission Capital Revenue Requirement Deferral Account ("2017 GTAITCRRDA")

66. In the Decision in the Greater Toronto Area ("GTA") Leave-to-Construct ("LTC") proceeding, EB-2012-0451, the Board ordered the Company to create a deferral account to track the revenue requirement impact in relation to $55 million in incremental capital spending which resulted from the upsizing of the transmission component of Segment A within the GTA project. In accordance with the Decision, the Company filed a Draft Accounting Order seeking approval to establish the Greater Toronto Area Incremental Transmission Capital Revenue Requirement Deferral Account ("GTAITCRRDA"). The Accounting Order was subsequently approved on March 11, 2014.

67. The purpose of the GTAITCRRDA is to record the revenue requirement related to an incremental $55 million of forecast capital costs which resulted from the upsizing Segment A of the GTA project to an NPS 42 pipeline, from an NPS 36 pipeline. The account will only be required in the event that at the time Segment A is put into service there are no Rate 332 transportation customer(s), or there is no ability for Rate 332 transportation customer(s) to utilize Segment A (i.e., TransCanada's King's North project is delayed).

68. The revenue requirement will represent revenue to be collected from transportation service customers once they are able to take service under Rate 332: Parkway to Albion Transportation Service. The rationale for calculating the revenue requirement associated with the incremental $55 million is to determine the annual impact of the incremental costs as a result of upsizing the pipeline for Rate 332 transportation purposes.

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

2017 Demand Side Management Variance Account ("2017 DSMVA")

70. The purpose of the 2017 DSMVA is to record the difference between the actual 2017 DSM spending and the budgeted $62.9 million included within 2017 rates (as outlined within Exhibit D1, Tab 4, Schedule 1 of this proceeding). Amounts determined to be over or under the budget included within Allowed Revenue will be recorded in the DSMVA, subject to the DSMCEIDA. In addition, any further variance in 2017 DSM spending and results, beyond the budget included within rates, which occurs as a result of Board decisions in ongoing or upcoming DSM proceedings, will be included within the DSMVA.

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

2017 Lost Revenue Adjustment Mechanism ("2017 LRAM")

72. The purpose of the 2017 LRAM is to record the amount of distribution margin gained or lost when the Company's DSM programs are less or more successful than budgeted, for the period January 1, 2017 to December 31, 2017.

73. When the utility's DSM programs are less successful than budgeted in the fiscal year, the utility gains distribution margin. Similarly, the utility loses distribution margin in the fiscal year when its DSM programs are more successful than budgeted.

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

<u>2017 Demand Side Management Incentive Deferral Account ("2017 DSMIDA")</u>

75. The purpose of the 2017 DSMIDA is to record the actual amount of the shareholder incentive earned by the Company as a result of its DSM programs. The criteria and formula used to determine the amount of any shareholder incentive, to be recorded in the DSMIDA, will be in accordance with the methodology established in the DSM Framework and Guidelines proceeding EB-2014-0134, and Enbridge's 2016-2020 DSM Plan proceeding EB-2016-0049.

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

<u>2017 Relocation Mains Variance Account ("2017 RLMVA")</u>

77. The establishment of the RLMVA, for each of 2017 and 2018, was approved by the Board within its Decision With Reasons in Enbridge's 2014 to 2018 Customized Incentive Rate Application, EB-2012-0459.

78. The purpose of the 2017 RLMVA is to record the revenue requirement impact of capital spending on mains relocation activities which varies from $12.6 million (which is the forecast capital cost for relocations included in the Board approved 2017 capital budget), if the revenue requirement impact is $5 million or greater. Similarly, the purpose of the 2018 RLMVA will be to record the cumulative revenue requirement impact of capital spending on mains relocation activities which varies from $12.6 million in each of 2017 and 2018 (which is the forecast capital cost for relocations included in each of the Board approved 2017 and 2018 capital budgets), if the cumulative revenue requirement impact is $5 million or greater.

79. The amount to be recorded within the 2017 RLMVA will be determined as follows:

a) If the spending for relocations activities in 2017 is more than the $12.6 million forecast, then Enbridge will eliminate the first $12.6 million to arrive at the remaining capital spend for use within a revenue requirement calculation, to account for the fact that the impact of the $12.6 million is already included within Allowed Revenues for 2017. The revenue requirement for 2017 will be calculated using the remaining capital spending for that year and if the resulting revenue requirement amount is at least $5.0 million, then the resulting amount will be recorded in the 2017 RLMVA for future recovery by Enbridge.

b) If the spending for relocations activities in 2017 is less than the $12.6 million forecast, then Enbridge will determine the revenue requirement that would have resulted had the unspent portion of that amount been spent. If the resulting amount is at least $5.0 million, then the resulting amount will be recorded in the 2017 RLMVA for future credit to ratepayers.

80. The amount to be recorded within the 2018 RLMVA will be determined as follows:

a) First, an amount (which may be positive or negative) related to the 2017 capital spending on relocations will be determined. That will be done by taking the difference (positive or negative) between actual capital spending and $12.6 million, and then determining the revenue requirement implications of that amount in 2018.

b) Second, the relevant revenue requirement amount related to 2018 capital spending on relocations will be added to the number determined in (a).

   i. If the spending for relocations activities in 2018 is more than the $12.6 million forecast, then Enbridge will eliminate the first $12.6 million to arrive at the remaining capital spend for use within a revenue requirement calculation, to account for the fact that the impact of the $12.6 million is already included within Allowed Revenue for 2018. The revenue requirement for 2018 will be calculated using the remaining capital spending for that year.

   ii. If the spending for relocations activities in 2018 is less than the $12.6 million forecast, then Enbridge will determine the 2018 revenue requirement that would have resulted had the unspent portion of that amount been spent.

c) If the sum of the amounts calculated under (a) and (b) above is more than $5.0 million (positive or negative), then that amount will be recorded in the 2018 RLMVA for future recovery.

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

<u>2017 Replacement Mains Variance Account ("2017 RPMVA")</u>

82. The establishment of the RPMVA, for each of 2017 and 2018, was approved by the Board within its Decision With Reasons in Enbridge's 2014 to 2018 Customized Incentive Rate Application, EB-2012-0459.

83. The purpose of the 2017 RPMVA is to record the revenue requirement impact of capital spending on miscellaneous mains replacement activities which varies from $5.1 million (which is the forecast capital cost for miscellaneous replacements included in the Board approved 2017 capital budget), if the revenue requirement impact is $5 million or greater. Similarly, the purpose of the 2018 RPMVA will be to record the cumulative revenue requirement impact of capital spending on miscellaneous mains replacement activities which varies from $5.1 million in each of 2017 and 2018 (which is the forecast capital cost for miscellaneous replacements included in each of the Board approved 2017 and 2018 capital budgets), if the cumulative revenue requirement impact is $5 million or greater.

84. The amount to be recorded within the 2017 RPMVA will be determined as follows:

a) If the spending for miscellaneous replacement activities in 2017 is more than the $5.1 million forecast, then Enbridge will eliminate the first $5.1 million to arrive at the remaining capital spend for use within a revenue requirement calculation, to account for the fact that the impact of the $5.1 million is already included within Allowed Revenues for 2017. The revenue requirement for

2017 will be calculated using the remaining capital spending for that year and if the resulting revenue requirement amount is at least $5.0 million, then the resulting amount will be recorded in the 2017 RPMVA for future recovery by Enbridge.

b) If the spending for miscellaneous replacement activities in 2017 is less than the $5.1 million forecast, then Enbridge will determine the revenue requirement that would have resulted had the unspent portion of that amount been spent. If the resulting amount is at least $5.0 million, then the resulting amount will be recorded in the 2017 RPMVA for future credit to ratepayers.

85. The amount to be recorded within the 2018 RPMVA will be determined as follows:

a) First, an amount (which may be positive or negative) related to the 2017 capital spending on miscellaneous replacements will be determined. That will be done by taking the difference (positive or negative) between actual capital spending and $5.1 million, and then determining the revenue requirement implications of that amount in 2018.

b) Second, the relevant revenue requirement amount related to 2018 capital spending on miscellaneous replacements will be added to the number determined in (a).

   i. If the spending for miscellaneous replacement activities in 2018 is more than the $5.1 million forecast, then Enbridge will eliminate the first $5.1 million to arrive at the remaining capital spend for use within a revenue requirement calculation, to account for the fact that the impact of the $5.1 million is already included within Allowed Revenues for 2018.

The revenue requirement for 2018 will be calculated using the remaining capital spending for that year.

ii. If the spending for miscellaneous replacement activities in 2018 is less than the $5.1 million forecast, then Enbridge will determine the revenue requirement that would have resulted had the unspent portion of that amount been spent.

c) If the sum of the amounts calculated under (a) and (b) above is more than $5.0 million (positive or negative), then that amount will be recorded in the 2018 RPMVA for future recovery

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

2017 Dawn Access Costs Deferral Account ("2017 DACDA")

87. Approval for the establishment of the DACDA was granted by the Board on November 20, 2014 in its approval of the Dawn Access Application and Settlement Agreement within proceeding EB-2014-0323.

88. The purpose of the 2017 DACDA is to record for recovery, the revenue requirement impact of the incremental costs incurred to implement the Dawn Transportation Service ("DTS"), including the costs for required system changes. Under the terms of the Settlement Agreement, recovery of amounts recorded in the DACDA will be from all bundled customers, regardless of whether they are system or direct purchase and regardless of the service to which they currently

subscribe, because all have the option of taking DTS if they so choose. Further details explaining the DACDA, including the recovery method, are included within Section 2.7 of the Settlement Agreement filed at Exhibit B, Tab 2, Schedule 1 of the EB-2014-0323 proceeding.

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

2017 Demand Side Management Cost-Efficiency Incentive Deferral Account ("2017 DSMCEIDA")

90. Approval for the establishment of the DSMCEIDA during the Company's 2015 - 2020 multi-year demand side management plan was granted by the Board within its Decisions and Orders in proceeding EB-2015-0049. As outlined, the Board ordered that Enbridge establish the DSMCEIDA for each year of the DSM plan beginning January 1, 2016.

91. The purpose of the 2017 DSMCEIDA is to record any differences between Enbridge's 2017 approved DSM budget and the actual amount spent to achieve the 2017 total aggregate annual lifetime savings (cumulative cubic metres of natural gas, or CCM) target, made up of all 100% CCM targets across all programs, in accordance with the program evaluation results. Any OEB-approved DSMCEIDA amounts will be available to use in meeting the Company's targets in a subsequent year over the 2015 - 2020 DSM term.

92. Simple interest is to be calculated on the opening monthly balance of this account using the Board Approved EB-2006-0117 interest rate methodology. The balance

in this account, together with carrying charges, will be disposed of in a manner designated by the Board in a future rate hearing.

2017 OEB Cost Assessment Variance Account ("2017 OEBCAVA")

93. As indicated in the OEB's letter to all regulated entities, dated February 9, 2016, titled "*Revisions to the Ontario Energy Board Cost Assessment Model*", the Board has updated its allocation of costs to regulated entities, which may result in "material shifts" in the costs that are allocated. The Board's letter authorized the establishment of an OEB Cost Assessment Variance Account for regulated entities, including the natural gas utilities.

94. The purpose of the 2017 OEBCAVA will be to record any variance between the OEB costs assessed to Enbridge under the prior cost assessment model, which were included in rates during the Custom IR term, and the OEB costs assessed to Enbridge under the new OEB cost assessment model. Entries into the variance account will be made on a quarterly basis when the OEB's cost assessment invoice is received.

95. Enbridge will submit an accounting order request to establish a similar account for 2016, which will be effective as of April 1, 2016, which is when the OEB's new cost assessment model became effective.

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

2017 Customer Care Services Procurement Deferral Account ("2017 CCSPDA")

97. Within the Board's EB-2012-0459 Decision with Reasons, dated July 17, 2014, the Board approved the establishment of the CCSPDA to capture the costs associated with benchmarking, tendering, and potential transition of customer care services to a new service provider(s). The account was approved for 2014 through 2016, and included a cumulative $5 million limit. The reason for this timing was that Enbridge's customer care outsourcing contract with Accenture was scheduled to expire on December 31, 2017, meaning that benchmarking and tendering associated with evaluating new service providers would be undertaken in years leading up to 2017.

98. In November 2014, the Company renegotiated the customer care outsourcing contract with Accenture and extended it to December 31, 2019, replacing the scheduled expiry date of December 31, 2017. The renegotiation and extension delayed any potential incurrence of benchmarking, tendering, and transition costs. Therefore, Enbridge did not incur any costs to be recorded in the CCSPDA.

99. At this time, the Company is in the process of assessing the option of a Request For Proposal ("RFP") for customer care outsourcing services to be issued in late 2017, to allow a potential new service provider(s) to be fully operational after the existing contract with Accenture expires on December 31, 2019.

100. Given the potential for the Company to choose the RFP option in the near future, Enbridge requests the continuation of the CCSPDA through 2017, 2018, and 2019, on the same terms as previously approved (including the $5 million limit).

The extension would give Enbridge the flexibility to design a customer care service delivery strategy that is in the best interest of ratepayers, in terms of service quality, productivity, technology and cost.

101. Enbridge would bring forward the costs recorded in the CCSPDA for recovery as part of the annual deferral and variance account clearance proceedings in 2018, 2019, and 2020. Simple interest would be calculated using the Board approved interest rate methodology.

<u>2017 Rate 332 Deferral Account ('2017 R332DA")</u>

102. Similar to 2016, the 2017 R332DA is being requested due to uncertainty as to whether Rate 332: Parkway to Albion Transportation Service will be available for all of 2017. Enbridge's current expectation is that service will be available for the entirety of 2017, and as a result has forecast Rate 332 revenues under that expectation. However, Rate 332 transportation service is dependent on the completion of TransCanada's King's North Project, which to date has not been placed into service. Therefore, in the event that Rate 332 transportation service is not available for the entirety of 2017, the purpose of the 2017 R332DA will be to record for clearance to the Company's bundled customers, any variance in Rate 332 revenues collected from Rate 332 transportation customers versus the amount forecast to be collected from those customers in 2017, net of any amounts recorded in the 2017 GTAITCRRDA. The R332DA will ensure that the Company's bundled customers only pay for the revenue requirement on the transportation component of Segment A, net of the revenue requirement on the incremental $55 million in upsizing costs, where Rate 332 transportation service is not available.

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