OPERATING COST SUMMARY

1. This evidence sets out an overview of Enbridge's 2015 Operating Costs, which forms part of the final 2015 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.
   - 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. Table 1 below, shows a summary of Enbridge's utility cost of service for each of the 2014 Board Approved (EB-2012-0459), the 2015 placeholder (EB-2012-0459), and the final 2015 Test Year operating costs forecast within this proceeding.

Witness: R. Small

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

Line No.		Col. 1 EB-2012-0459 2014 Total Approved Costs and Expenses ($Millions)	Col. 2 EB-2012-0459 2015 Total Costs and Expenses Placeholder ($Millions)	Col. 3 2015 Test Year CIR Utility Costs and Expenses ($Millions)
1.	Gas costs	1,456.3	1,606.8	1,687.1
2.	Operation and maintenance	425.3	427.3	432.3
3.	Depreciation and amortization expense	248.5	261.7	261.7
4.	Fixed financing costs	1.9	1.9	1.9
5.	Municipal and other taxes	41.2	43.1	43.1
6.	Operating costs	2,173.2	2,340.8	2,426.1
7.	Income tax expense (incl. taxes on suff./def.)	8.9	3.4	15.6
8.	Cost of Service (excl. interest & return)	2,182.1	2,344.2	2,441.7

4. The numeric impacts of each of the 2015 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 case/CIS costs, pension/OPEB costs and DSM costs).

5. The evidence with respect to the updated forecast of gas costs can be found at Exhibit D1, Tab 2, Schedules 1 to 8. The overall impact of the adjustment to the placeholder amount (which kept 2015 gas costs at the same level as 2014) is an increase of $80.3 million. This takes account of the updated 2015 gas volume

forecast, as well as the October 1, 2014 QRAM prices and the 2015 gas supply plan.

6. The evidence with respect to the updated 2015 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 2015 customer case/CIS costs is a decrease of $0.7 million in operating costs.

7. 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 2015 DSM costs is an increase of $2.2 million in operating costs.

8. 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 2015 pension and OPEB costs is an increase of $3.5 million in operating costs.

9. 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. Evidence with respect to the updated income tax amount can be found at Exhibit D1, Tab 6, Schedules 1 and 2.

COST OF SERVICE
2015 UPDATED FORECAST

Line No.		Col. 1 EB-2012-0459 2015 Utility Placeholder Costs and Expenses ($Millions)	Col. 2 2015 CIR Update Adjustments ($Millions)	Col. 3 2015 Updated CIR Utility Costs and Expenses ($Millions)
1.	Gas costs	1,606.8	80.3	1,687.1
2.	Operation and maintenance	427.3	5.0	432.3
3.	Depreciation and amortization expense	261.7	-	261.7
4.	Fixed financing costs	1.9	-	1.9
5.	Municipal and other taxes	43.1	-	43.1
6.	Interest and financing amortization expense	-	-	-
7.	Other interest expense	-	-	-
8.	Total costs and expenses	2,340.8	85.3	2,426.1

EXPLANATION OF ADJUSTMENTS TO UTILITY COSTS AND EXPENSES
2015 UPDATED FORECAST

Line No. Adj'd	Adjustments ($Millions)	Explanation
1.	80.3	Gas costs
		Adjustment to 2015 placeholder gas costs to reflect the updated 2015 volume forecast, gas supply plan, and October 1, 2014 QRAM prices.
2.	5.0	Operation and maintenance

	2015 Update	2015 Placeholder	Change
Pension and OPEB accrual cost update	37.3	33.8	3.5
DSM cost update	35.0	32.8	2.2
Customer Care/CIS cost update	95.8	96.5	(0.7)
			5.0

GAS COSTS, TRANSPORTATION, AND STORAGE

1. The purpose of this evidence is to provide an overview of the gas cost consequences of the gas supply activities, including storage and transportation of Enbridge Gas Distribution Inc. (the “Company” or “Enbridge”) during the 2015 Test Year. The process for calculating budgeted gas costs is consistent with prior years. Using the forecasted volumetric demand requirements the Company develops a gas supply plan using a model known as “SENDOUT”. This model determines the optimum monthly supply portfolio using existing contractual parameters i.e., transportation contracts including storage deliverability and also provides the Company with a forecast of monthly storage targets. Once the monthly supply portfolio and storage targets have been established then gas costs can be calculated.

Gas Supply

2. Enbridge expects to acquire its system gas supply under the following types of contracts during the Test Year:

- Western Canadian Supplies: These supplies source gas in the supply area of Western Canada and will be transported either via TransCanada PipeLines Limited (“TransCanada or “TCPL”) or via Alliance Pipeline to the Company’s franchise area.
- Ontario Production: The Ontario supply is *de minimus* in relative terms.
- Peaking Contracts: These contracts source gas from other suppliers in the Eastern Zone during the winter season.
- Chicago Supply: These supplies are to be acquired in Chicago and transported to Dawn via the Company’s contracted capacity on the Vector Pipeline.

- Delivered Supply: These supplies are forecasted to be acquired directly at the Dawn Hub.
- Niagara Supply: These supplies are forecasted to be acquired at the Niagara Import/Export point.

Enbridge Gas Distribution currently buys all of its gas on an indexed basis. It does not have any existing contracts that provide supply on a fixed price basis. The Company expects to continue this practice for its 2015 gas supply arrangements.

3. The following is Enbridge's forecast of gas supply acquisition during the 2015 Test Year:

Contract Type	Volume 10^6m^3	Bcf
Western Canadian Supply	4 783.3	168.9
Ontario Production	0.7	0.0
Peaking	7.7	0.3
Chicago Supply	1 843.7	65.1
Delivered Supply	700.5	24.7
Niagara Supply	323.7	11.4
	7 659.6	270.4

Commodity Costs

4. The price assumptions reflect the market's assessment (as at the time of preparation of this evidence) of prices at the different expected delivery points for the Company's forecast of gas supply.

5. The market's assessment is determined at any point in time by the use of the 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.

6. The Company prepared its gas supply forecast based upon a 21-day average of various indices from August 1, 2014 to August 29, 2014 for the 12 months commencing January 1, 2015 (Exhibit D1, Tab 2, Schedule 7) and applied these monthly prices to the 2015 budgeted annual volume of gas purchases.

7. In an effort to isolate the impact of commodity costs changes, the Company removed the impact of the updated price forecast and the October 1, 2014 QRAM prices in a fashion similar to that used in the determination of the 2014 gas cost budget that was filed in EB-2012-0459.

8. Any variance between the actual commodity cost and the forecasted prices will be captured in the 2015 Purchased Gas Variance Account ("PGVA"). Also, any variation in the forecasted transportation tolls and the actual tolls will be captured in the 2015 PGVA. While the Company has prepared the 2015 forecast assuming that it will be acquiring gas in 2015 via traditional transportation paths (i.e., TCPL, Alliance/Vector) the possibility does exist in the future to acquire gas via alternative means.

9. Enbridge proposes that the 2015 volumetric forecast as set out at Exhibit D1, Tab 2, Schedule 4 be used, on an interim basis, for the purpose of deriving reference prices in 2015 QRAM applications by Enbridge, until such time as a final decision in this proceeding is implemented. Following Board approval of 2015

volumes any adjustments, if necessary, will be made within the next QRAM application.

<u>Peak Day Coverage</u>

10. In EB-2011-0354 Enbridge presented a new Design Criteria Study which all parties agreed to accept on a phased in approach. The Design Day Criteria is based upon a 1 in 5 recurrence interval. The new Design Criteria Study was filed in EB-2011-0354 at Exhibit D1, Tab 2, Schedule 3. The Company has prepared its 2015 Gas Cost budget assuming a peak day forecast based upon 41.4 degree days (Celsius) for the coldest peak. Enbridge is currently forecasting a design peak day level of 105 534 10^3m^3 (3.7 Bcf) during the winter season of the 2015 Test Year.

11. The Company has chosen to maintain the same level of Peaking Services for 2015 as was forecast for 2014. Also, similar to 2014 the Company chose to rely principally on TCPL FT service to meet the 2015 Peak Day Demand. The driver for this decision is based upon events at the National Energy Board ("NEB"). On March 27, 2013 the NEB issued its decision in TransCanada Compliance filing RH-003-2011. As discussed as part of the Settlement Agreement in EB-2012-0459 at Exhibit N1, Tab 2, Schedule 1, the ability for TCPL to charge for STFT service an amount in excess of the FT toll made contracting for STFT service inappropriate. TCPL is currently offering STFT service for the November 2014 to March 2015 period at a minimum bid floor of 1,200% of the current FT toll for each month.

12. The Company intends to continue to monitor the availability of transport to the franchise area and to look for alternatives that will provide value to the customers of Enbridge while still providing safe and reliable service. If alternatives are found

then any differences in the cost of those services versus those forecasted as part of the 2015 gas costs will be captured in the 2015 PGVA.

13. The Company's plan for meeting its peak day requirements in 2015 includes an increase in TCPL FT capacity of approximately 150,000 GJ/day driven primarily by four factors compared to 2014: 1) an increase in the overall peak day demand due to growth, 2) a decline in the level of interruptible volume largely stemming from a decline in the number of interruptible customers, 3) the migration of Ontario T-Service ("OTS") customers to either System Sales or Western T-Service ("WTS"), and 4) a decrease in available delivered service supplies. Prior to renewal of their contracts with Enbridge a number of interruptible customers including institutional customers such as schools and hospitals indicated that the curtailment costs they experienced this past winter were excessive and requested to move from an Interruptible ("IT") Rate to a Firm Rate. The Company evaluated the requests on a case by case basis and once it was determined that a switch from IT to Firm would not impact the distribution system, customers were allowed to move to a Firm Rate. As a consequence, the Company had to look for additional supplies to meet its peak day requirements. OTS customers are required, under their direct purchase agreement, to deliver a daily volume directly into the franchise area. The migration of customers from OTS to either System Sales or to WTS results in less volume being delivered directly into the franchise area by Direct Purchase customers. As a consequence, the Company had to look for additional supplies to meet its peak day requirements. A breakdown of the peak day requirement and supply forecast is shown at Exhibit D1, Tab 2, Schedule 6.

14. Similar to 2014, the incremental capacity required to meet forecasted 2015 peak day demand will not be utilized at a 100% load factor based upon the 2015

volumetric forecast. The Company is forecasting $166.4 million in cost /u consequences associated with unutilized transportation capacity. This forecast is also based upon the TCPL tolls in place at the time of the derivation of the October 2014 QRAM. As part of the Settlement Agreement in EB-2012-0459 parties agreed that, instead of including a forecasted Unabsorbed Demand Charge ("UDC") amount in gas costs for rate making purposes, any actual UDC costs incurred during the year would be captured in either the 2014 DDCTDA or the 2014 UDCDA. The Company is proposing a similar treatment be used in 2015 with one minor exception. The Company believes that any costs associated with actual UDC costs can be tracked through a single deferral account and is therefore proposing the 2015 Unabsorbed Demand Charges Deferral Account ("2015 UDCDA"). In 2015 Enbridge will use best efforts to mitigate UDC that would otherwise be recorded in the 2015 UDCDA. For example, during the summer months when the Utility is injecting gas into storage, whenever possible, the Company will use transportation capacity to displace discretionary purchases of gas at Dawn. If there still remains unutilized capacity the Company will use best efforts to make that capacity available to third parties to mitigate the UDC costs. Similar to 2014 the Company intends to continue to provide monthly reporting of the on-going amounts in the 2015 UDCDA. The Company has provided at Appendix A, a monthly breakdown of the forecasted 2015 UDCDA.

<u>Transportation</u>

15. Enbridge has a number of Firm Transportation ("FT") and other service entitlements in place for system gas sourced in Western Canada or in the United States (at the Chicago hub as well as U.S. supply area), or both, during the 2015 Test Year. These include service entitlements with TransCanada (both long haul and short haul), Alliance Pipeline and Vector Pipeline. For purposes of this forecast,

contracts were priced based upon current tolls and if contracts had an expiry date during the Test Year these contacts were assumed to expire. For instance, the Company has chosen not to renew its contract with Alliance Pipeline as well as two Vector Pipeline contracts totaling 100 000 MMBTU/d. These contracts expire on November 30, 2015 and October 31, 2015 for each pipeline respectively. Included in the forecasted supply portfolio effective November 1, 2015 is the acquisition of 200 000 GJ/day of supply at the Niagara interconnect on TCPL. In order to transport that gas from the Niagara import point, the Company has assumed the acquisition of 200 000 GJ/day of Niagara Falls to Enbridge Parkway CDA capacity on TCPL.

16. For the purposes of the 2015 forecast the Company has assumed the assignment of 31,098 Gj/day of TCPL short haul capacity to Direct Purchase customers effective November 1, 2014 to October 31, 2015.

17. With the forecasted in service date of November 1, 2015 for the GTA Project, the Company is assuming a number of changes in its plan to meet its peak day demand. A number of TCPL FT contracts will be allowed to expire, the Company will no longer rely on peaking service in the CDA and Direct Purchase customers will be allowed to shift their deliveries to Dawn, as proposed in the Dawn Access Settlement Agreement recently approved by the Board (EB-2014-0323). Phase 1 will consist of an assignment of up to 149,818 GJ/day of TCPL Dawn to CDA short haul capacity). Replacing these, the Company will increase its reliance on M12 service entitlements with Union Gas.

18. M12 service entitlements on the Union system currently total 2,225,102 GJ/day (2,081 MMcf/day) and for the purposes of the 2015 gas cost budget are forecast to

increase by 400,000 GJ/day (375 Mmcf/day) commensurate with the in-service date of the GTA Project. M12 provides for delivery of gas by Union at Dawn for storage injection or onward transportation, for gas withdrawn from storage at Tecumseh or Union, or both, and for gas sourced in Western Canada or the United States, or both, and delivered at Dawn for onward transportation. The Company also has M16 transportation capacity with Union to facilitate the Chatham "D" Storage pool. The gas cost forecast assumed January 1, 2014 Union tolls. A list of the Company's transportation contracts can be found at Exhibit D1, Tab 2, Schedule 2.

Storage

19. The Company 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.

20. The Company also has contracted 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. For purposes of the 2015 gas cost forecast the Company has assumed the amount and value of storage set to be extended. Any variation between this assumed cost and the actual cost of storage acquired through an RFP process will be captured in the 2015 Storage & Transportation Deferral Account (2015 S&TDA).

21. In the April 2014 and October 2014 QRAM proceedings (EB-2014-0039 and EB-2014-0191 respectively) the Company discussed its utilization of storage as a

part of its gas supply plan. Historically the Company would establish storage targets to maintain sufficient deliverability from storage and would maintain maximum deliverability until late January to early February in order to meet design day 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 above budget. Developing a gas supply plan in this fashion proved satisfactory during periods of budgeted or slightly colder than budget winters. This was not the case in the winter of 2014 and the Company was forced to purchase significantly higher volumes of gas at Dawn to serve the needs of its customers.

22. For purposes of preparing the 2015 gas supply plan the Company has implemented a change with respect to how it plans to manage its storage balances. The Company is forecasting storage targets such that maximum deliverability from storage can be maintained until the end of February and such that deliverability from storage is sufficient to meet March peak day as late as March 31. An advantage of maintaining higher storage balances until the end of February is that in the event of colder than budgeted demand in the month of March the Company can reduce the requirement of daily spot purchases at presumably higher prices.

23. Also during the April 2014 and October 2014 QRAM proceedings the Company explained its long term practice of the use of a seven day ahead forecast of degree days along with budgeted weather beyond seven days to make gas procurement decisions. The Company plans to make a change in how it uses forecasted weather to make procurement decisions next winter. The Company will continue to rely on a seven day ahead forecast of degree days as part of its decision making process for gas procurement for the upcoming week. The Company, however,

intends to look to medium term weather forecasts as a means of assessing medium term demand impacts in order to help decide whether or not it should adjust its supply plan for the upcoming month or the remainder of the winter season. The Company currently tracks several medium term weather forecasts and will look to some consensus of these forecasts as another indicator of future demand. Depending on a number of factors (such as the point in the winter when the decision is being made, where storage balances are relative to target, what is happening in the markets where the Company purchases gas) the Company may choose to adjust its month ahead and/or seasonal purchases taking into consideration not only budgeted weather but also medium term weather forecasts. The cost consequences of such decisions will be reflected within the PGVA.

24. Maintaining higher storage balances later into the winter season in conjunction with using a medium term weather forecast (as described above) will allow the Company to react sooner and more effectively to make adjustments to the supply plan to meet changing demand. By reacting sooner it will provide for an ability to acquire month ahead supplies to help reduce daily spot purchases. Conversely in a warmer than normal year the longer term forecast will allow for the potential to reduce purchases sooner.

Energy Content

25. 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.

Relief Requested

26. Based on the evidence above the Company requests recovery of the 2015 gas costs included within 2015 Allowed Revenue and the approval of the proposed 2015 UDCDA.

Budget

Demand	January	February	March	April	May	June	July	August	September	October	November	December		
PJ's	70.0	61.0	53.8	33.3	20.9	14.7	13.4	13.3	15.0	27.3	41.7	60.6	425.0	

Forecasted Monetary Impacts by Delivery Area
$ millions

	January	February	March	April	May	June	July	August	September	October	November	December		
UDCDA														
- CDA	-	-	7.0	10.6	8.5	8.5	8.5	8.5	10.0	10.0	6.1	6.1	83.9	
- EDA	-	-	11.6	9.4	8.5	8.5	8.5	8.5	7.5	7.5	6.3	6.3	82.5	
Revenue From Unutilized Capacity Released	-	-	-	-	-	-	-	-	-	-	-	-	-	
Net Impact on Deferral Account	-	-	18.6	20.0	17.0	17.0	17.0	17.0	17.6	17.6	12.3	12.3	166.4	/u

Forecasted Monthly Unutilized Capacity by Delivery Area
PJ's -

	January	February	March	April	May	June	July	August	September	October	November	December		
UDCDA														
- CDA	-	-	3.6	5.3	4.3	4.2	4.3	4.3	5.0	5.1	3.0	3.1	42.2	
- EDA	-	-	5.7	4.5	4.2	4.1	4.2	4.2	3.6	3.7	3.0	3.1	40.3	
Unutilized Capacity Released	-	-	-	-	-	-	-	-	-	-	-	-	-	
Net Unutilized Capacity	-	-	9.3	9.8	8.5	8.3	8.5	8.5	8.6	8.8	6.0	6.2	82.5	

Degree Days														
Central Region	682.0	596.0	506.0	306.0	133.0	27.0	-	5.0	59.0	238.0	392.0	592.0	3,536.0	/c
Niagara Region	647.0	587.0	490.0	301.0	130.0	22.0	-	3.0	48.0	210.0	373.0	565.0	3,376.0	/c
Eastern Region	826.0	706.0	595.0	339.0	152.0	38.0	8.0	21.0	110.0	285.0	467.0	720.0	4,267.0	/c

Discretionary Requirement

	January	February	March	April	May	June	July	August	September	October	November	December	
PJ's	4.0	4.0	-	0.0	0.0	3.0	3.1	3.1	3.0	3.1	-	3.1	26.4

Month end Storage Capacity Target

% Fill	0.53	0.37	0.20	0.17	0.26	0.42	0.59	0.77	0.92	1.00	0.93	0.72
Bcf	60.56	42.57	22.64	19.08	29.56	47.69	68.06	88.50	106.01	113.00	106.21	82.42

STATUS OF TRANSPORTATION CONTRACTS

Item #	Transportation	Route	Total Contracted Daily Volume		Fuel Rate	Monthly Demand Charge		Estimated Commodity Charge		Expiry Date
	Current Contracts									
1	TCPL FT - CDA	Empress to CDA	63,468	GJ	varies	47.62803	$/GJ	-	$/GJ	31-Oct-17
2	TCPL FT - CDA	Empress to CDA	201,070	GJ	varies	47.62803	$/GJ	-	$/GJ	31-Oct-15 (1)
3	TCPL FT - CDA	Empress to CDA	9,000	GJ	varies	47.62803	$/GJ	-	$/GJ	31-Oct-15
4	TCPL FT - CDA	Empress to CDA	56,000	GJ	varies	47.62803	$/GJ	-	$/GJ	31-Dec-15
5	TCPL FT - EDA	Empress to EDA	197,421	GJ	varies	49.13597	$/GJ	-	$/GJ	31-Oct-17
6	TCPL FT - EDA	Empress to EDA	50,000	GJ	varies	49.13597	$/GJ	-	$/GJ	31-Mar-15
7	TCPL FT - EDA	Empress to EDA	116,250	GJ	varies	49.13597	$/GJ	-	$/GJ	31-Oct-15
8	TCPL FT - EDA	Empress to EDA	166,000	GJ	varies	49.13597	$/GJ	-	$/GJ	31-Oct-16 (2)
9	TCPL FT - Iroquois	Empress to Iroquois	26,956	GJ	varies	49.45575	$/GJ	-	$/GJ	31-Oct-17
10	TCPL FT Dawn to CDA		149,818	GJ	varies	7.16453	$/GJ	0.01360	$/GJ	31-Oct-17 (3)
11	TCPL FT Dawn to CDA	Assignment to Direct Purchase	(31,098)	GJ	varies	7.16453	$/GJ	0.01360	$/GJ	31-Oct-16 (3)
12	TCPL FT Dawn to EDA		114,000	GJ	varies	13.28433	$/GJ	0.03229	$/GJ	31-Oct-17
13	TCPL FT Dawn to Iroquois		40,000	GJ	varies	12.76919	$/GJ	0.03038	$/GJ	31-Mar-16
14	TCPL FT Parkway to CDA		572	GJ	varies	3.14523	$/GJ	0.00350	$/GJ	31-Oct-17
15	TCPL FT-SN Parkway to CDA		85,000	GJ	varies	3.17490	$/GJ	0.00326	$/GJ	31-Oct-18
16	TCPL STS Parkway to CDA		283,892	GJ	varies	1.69730	$/GJ	0.00024	$/GJ	31-Oct-17
17	TCPL STS Parkway/Kirkwall to EDA		70,895	GJ	varies	4.84530	$/GJ	0.00757	$/GJ	31-Oct-17
18	TCPL STS Parkway to EDA		9,716	GJ	varies	4.84530	$/GJ	0.00757	$/GJ	31-Oct-17
19	Niagara to CDA		200,000	GJ	N/A					
20	Nova Transmission	AECO to Empress	166,869	GJ	N/A	5.35000	$/GJ	-	$/GJ	31-Oct-16
21	Nova Transmission	AECO to Empress	20,000	GJ	N/A	5.35000	$/GJ	-	$/GJ	31-Oct-15
22	Alliance Pipeline	Alberta to US border	2,124.6	10^3m^3	varies	981.1600	$\$/10^3m^3$	-	$\$/10^3m^3$	30-Nov-15 (4)
23		US border to Chicago	75.0	mmcf	varies	16.5000	$US/dth	-	$US/dth	30-Nov-15
24	Vector Pipeline -	Chicago to Cdn border	96,000	dth	varies	7.0140	$US/dth	-	$US/dth	30-Nov-17
25		Cdn border to Dawn	101,285	GJ	varies	0.5705	$/GJ	-	$/GJ	30-Nov-17
26	Vector Pipeline	Chicago to Cdn border	79,000	dth	varies	7.0140	$US/dth	-	$US/dth	30-Nov-17
27		Cdn border to Dawn	83,349	GJ	varies	0.5705	$/GJ	-	$/GJ	30-Nov-17
28	Vector Pipeline -	Chicago to Cdn border	50,000	dth	varies	Negotiated Toll				30-Nov-15 (5)
29		Cdn border to Dawn	52,753	GJ	varies	Negotiated Toll				30-Nov-15 (5)
30	Vector Pipeline -	Chicago to Cdn border	50,000	dth	varies	Negotiated Toll				30-Nov-15 (5)
31		Cdn border to Dawn	52,753	GJ	varies	Negotiated Toll				30-Nov-15 (5)
32	Union Gas Dawn to Parkway		1,764,678	GJ	varies	2.3820	$/GJ	-	$/GJ	31-Mar-14 (6)
33	Union Gas Dawn to Parkway		106,000	GJ	varies	2.3820	$/GJ	-	$/GJ	31-Oct-18
34	Union Gas Dawn to Parkway		57,100	GJ	varies	2.3820	$/GJ	-	$/GJ	31-Oct-19
35	Union Gas Dawn to Parkway		18,703	GJ	varies	2.3820	$/GJ	-	$/GJ	31-Oct-14
36	Union Gas Dawn to Parkway		200,000	GJ	varies	2.9610	$/GJ	-	$/GJ	31-Oct-22
37	Union Gas Dawn to Lisgar		10,692	GJ	varies	2.3820	$/GJ	-	$/GJ	31-Oct-14
38	Union Gas Dawn to Kirkwall		35,806	GJ	varies	2.0110	$/GJ	-	$/GJ	31-Oct-14
39	Union Gas Dawn to Kirkwall		32,123	GJ	varies	2.0110	$/GJ	-	$/GJ	31-Mar-14
40	Union Gas Parkway to Dawn		236,586	GJ	varies	0.5790	$/GJ	-	$/GJ	31-Mar-14

notes:
(1) in the event of a delay in the GTA project these contracts continue beyond October 31, 2015
(2) Contract Effective November 1, 2015
(3) In addition to the toll provided above there is a monthly surcharge as well - $0.13281/GJ/month
(4) the Alliance contract will not be renewed beyond the November 30, 2015 expiry date
(5) these Vector contracts will not be renewed beyond the November 30, 2015 expiry date
(6) the Company is planning to contract for an incremental 400,000 Gj/day of M12 capacity effective November 1, 2015
(7) volume increases to 75,000 in second year of contract

Pending Contracts to meet Peak Day in 2015

Item #	Transportation	Route	Total Contracted Daily Volume		Fuel Rate	Monthly Demand Charge		Estimated Commodity Charge		Effective Date	Expiry Date
41	Peaking Service - CDA		105,505			varies		varies		1-Dec-14	31-Mar-15
42	Peaking Service - EDA		52,753			varies		varies		1-Dec-14	31-Mar-15
			158,258								
43	TCPL FT - CDA	Empress to CDA	75,000	GJ	varies	47.62803	$/GJ	-	$/GJ	1-Jan-15	31-Oct-18
44	Nova Transmission	AECO to Empress	75,000	GJ	N/A	5.35000	$/GJ	-	$/GJ	1-Jan-15	31-Dec-15
45	Niagara to CDA		25,000			Negotiated Toll				1-Nov-13	31-Mar-15
46	Niagara to CDA		60,000			Negotiated Toll				1-Nov-14	1-Mar-16 (7)
47	Dawn to CDA		25,000			Negotiated Toll				1-Nov-13	31-Mar-15
48	Dawn to CDA		25,000			Negotiated Toll				1-Nov-14	1-Mar-16

Witness: D. Small

UNBILLED AND UNACCOUNTED-FOR GAS VOLUMES

Producing the UUF Forecast – 2015 Test Year

1. This evidence describes the forecast methodology and updates the forecast of Unbilled and Unaccounted-For Gas (“UUF”) for the 2015 Test Year. The 2015 UUF forecast of 96,707 10^3m^3 is part of the 2015 volumes budget, and will be used as the pivot point for the Unaccounted-For Variance Account (“UAFVA”).

2. The UUF volumes are part of the annual volumetric adjustment which was proposed by the Company and approved by the Board’s EB-2012-0459 Decision with Reasons dated July 17, 2014. Only the 2015 UUF is described in the evidence for this proceeding as the Company intends to update forecast UUF for 2016, 2017, and 2018 in subsequent annual adjustments as consistent with the EB-2012-0459 Decision.

3. The UUF forecast is produced using a two-step process involving the forecast of both Unaccounted-For Gas (“UAF”) and unbilled volumes. The 2015 UUF forecast is equal to the 2015 UAF forecast plus the expected difference between the December 2015 and December 2014 unbilled volumes (i.e., change in unbilled volumes). Both the UAF and unbilled volumes forecasts are generated using regression models.

4. 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

5. 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.

6. The change in unbilled volumes from December 2014 and December 2015 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")

7. The Company regularly tests a variety of forecasting models in order to ensure that the UAF forecast is as accurate as possible. These models incorporate multiple explanatory variables to model the variability in recorded UAF.

8. To re-estimate the models for the 2015 forecast, the Company included recorded UAF volumes to 2013 and sought to include other driver variables. Data collection remains challenging for other explanatory variables. Based on the accuracy results of the various models, two models emerged with the lowest comparable errors. The first model is the same regression model that has been in place for a number of years which features the level of unlocked customers as a proxy for the size of the distribution system and an additional dummy variable for 2013 ("Model A"). The other is based on a trend variable ("Model B"). The following paragraphs will focus on the results of these two prominent models.

9. Model A relies on the total number of unlocked customers as its primary explanatory variable to proxy for the size of the distribution system. The greater the number of customers, the larger the distribution network, the greater the potential for UAF volume, all other things equal. The linear equation is specified as follows, where the coefficient for unlocked customers, β_1, is positive.

Figure 1
Model A specification[1]

$$UAF_t = \beta_0 + \beta_1 * LOG(ULKS)_t + \beta_2 * DUM02_t + \beta_3 * DUMNEG_t + \beta_4 * DUM2013_t + \varepsilon_t$$

10. Model A also includes variables to account for a structural change in 2002, a negative UAF value, as well as higher than anticipated UAF in 2013. Since the UAF values are generally lower after 2002 compared to prior, it is expected that β_2 will be negative. As well, the variable that accounts for the negative UAF value will similarly have a negative coefficient (β_3). Including the variable to account for the negative value in 2004 ensures that the forecast is greater than zero. As the term 'unaccounted-for' suggests, it is expected that billed consumption will be less than sendout volumes and thus UAF volumes should be greater than zero. Finally, a variable to account for two high-pressure damages that occurred in 2013 was included, and the coefficient for β_4 is expected to be positive. By accounting for these damages in the model, the forecast is then able to discount for their effects in the future and return a value that is consistent with the estimated relationship with unlocked customers.

[1] Model A is specified as a linear equation of the following form:

UAF = -2,820,813 +206,497.9*LOG(ULKS)–103,600*DUM02–59,080.5 * DUMNEG + 44,184.5 * DUM2013
(t-stats) (-3.52) (3.61) (-4.07) (-6.06) (3.94)
$R^2 = 0.66$ F-statistic=8.73 Prob(F-statistic)=0.00

Witnesses: H. Sayyan
M. Suarez

11. In comparison, Model B relies on a trend variable as its primary explanatory variable. It purports that UAF volumes follow a trend over time. While that is difficult to rationalize given the highly volatile nature of the series, the trend variable is significant. The linear equation is specified as follows, where the trend coefficient, β_1, is positive.

Figure 2
Model B specification[2]

$$UAF_t = \beta_0 + \beta_1 * DUM02_t + \beta_2 * DUMNEG_t + \beta_3 * TREND_t + \varepsilon_t$$

12. As with Model A, variables were included to account for the structural change in 2002 and a negative UAF value. A variable was similarly included to account for the high-pressure damages in 2013, but was removed because it was not significant.

13. Forecast accuracy for each of the models was measured using both in-sample and out-of sample Mean Absolute Percentage Error ("MAPE"). In-sample, or ex-post, means that the estimated model incorporates the entire sample. Out-of-sample, or ex-ante, means that the model incorporates only a portion of the sample. For instance, to measure the error for 2009 (Table 1, Column 3), the in-sample approach incorporates the years from 1991 to 2009 in its model estimation and forecasts the 2009 UAF value. That forecast is then compared to the 2009 recorded value for UAF to determine the error. In contrast, the out-of-sample approach estimates the period from 1991 to 2007 to forecast the 2009 value. This latter approach is comparable to the test year forecasting process which employs a two-year hold out period (e.g., for the 2015 year, actual results are included to 2013).

---

[2] Model B is specified as a linear equation of the following form:

UAF = 45,677.6–112,679.6*DUM02–51,747.6* DUMNEG + 7,411 * Trend
(t-stats) (4.13) (-5.15) (-1.93) (4.59)
$R^2 = 0.68$ F-statistic=13.2 Prob(F-statistic)=0.00

Witnesses: H. Sayyan
M. Suarez

Table 1:

Model A & B: In-sample and Out-of-sample errors

Col. 1	*Col. 2*	*Col. 3*	*Col. 4*	*Col. 5*	*Col. 6*	*Col. 7*	*Col. 8*	*Col. 9*
Model	**Dependent Variable**	**Independent Variable(s)**	**Absolute IN-SAMPLE Errors**					
			2009	**2010**	**2011**	**2012**	**2013**	**Average (2009-2013)**
A	UAF	LOG(ULKS), DUM02, DUMNEG, DUM13	49.2%	13.8%	8.8%	4.9%	0.0%	15.4%
B	UAF	DUM02, DUMNEG, TREND	40.7%	1.0%	7.2%	11.6%	19.2%	15.9%

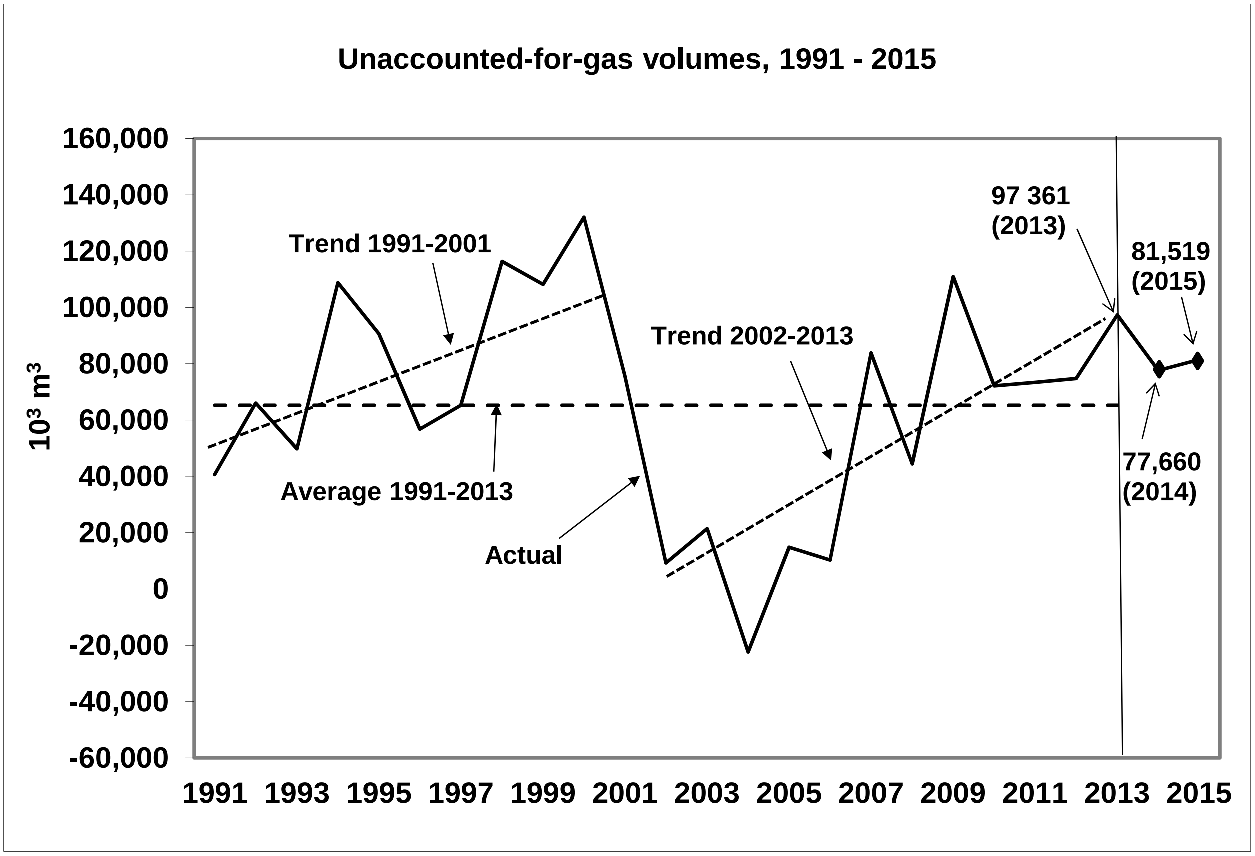
Model	**Dependent Variable**	**Independent Variable(s)**	**Absolute OUT-OF-SAMPLE Errors**					
			2009	**2010**	**2011**	**2012**	**2013**	**Average (2009-2013)**
A	UAF	LOG(ULKS), DUM02, DUMNEG, DUM13	59.9%	33.1%	13.2%	7.4%	37.7%	30.3%
B	UAF	DUM02, DUMNEG, TREND	50.9%	17.6%	9.4%	16.7%	22.0%	23.3%

14. As seen in the results from Table 1, while both models have similar average in-sample error (Column 9) over the last 5-year period (2009 to 2013), Model B's average out-of-sample error (Column 9) is lower than Model A's, suggesting a higher level of accuracy.

15. In selecting its forecast model, the Company did not rely solely on the accuracy of results but also on the reasonableness of the forecast. While Model B shows a lower error rate over the last 5-year period, it produced a UAF forecast of 110,863 10^3m^3 for 2015. In comparison, Model A's 2015 UAF forecast is more conservative at 81,519 10^3m^3 and more closely reflects the pace of customer growth. The Company has chosen to use Model A for 2015 UAF volumes based on the resulting forecast values.

16. Figure 3 shows historical UAF data to 2013 along with the 2014 and 2015 Test Year forecasts. The graph also shows the 1991 to 2001 trend, the 2002 to 2013 trend line, and the 1991 to 2013 average.

Figure 3



***Forecast values are based on a regression model produced in February 2013 (for 2014), and May 2014 (for 2015)**.

17. Table 2 below presents UAF actuals along with Board Approved values for the past five years.

Table 2

UAF Actuals vs Board Approved

Col. 1	*Col. 2*	*Col. 3*
Calendar Year	**Actual**	**Board Approved**
2009	110,917	31,841
2010	72,104	37,795
2011	73,355	64,211
2012	74,762	68,925
2013	97,361	73,092

Witnesses: H. Sayyan
M. Suarez

18. Table 3 below displays the historical UAF and unlock data used in the selected regression model to generate the forecast UAF for the 2015 Test Year.

Table 3

UAF Volumes and total unlocks, calendar 1991 to 2015
(volumes in 10^3m^3)

Col. 1	*Col. 2*	*Col. 3*
Calendar Year	**UAF Volumes**	**Unlocks**
1991	40,662	1,067,691
1992	66,028	1,104,224
1993	49,782	1,146,420
1994	108,765	1,188,226
1995	90,655	1,232,989
1996	56,739	1,274,338
1997	65,228	1,325,700
1998	116,376	1,376,564
1999	108,201	1,426,783
2000	132,021	1,479,413
2001	75,606	1,529,651
2002	9,284	1,580,819
2003	21,412	1,635,855
2004	-22,406	1,688,843
2005	14,815	1,735,906
2006	10,274	1,782,813
2007	83,823	1,824,789
2008	44,424	1,865,020
2009	110,917	1,887,605
2010	72,104	1,926,294
2011	73,355	1,960,378
2012	74,762	1,994,900
2013	97,361	2,030,000
2014B	77,660	2,063,725
2015 Test Year*	81,519	2,098,473

*Forecast values are based on a regression model produced in May 2014

Witnesses: H. Sayyan
M. Suarez

<u>Calculation of 2015 UUF</u>

19. The total UUF forecast is generated by adding the forecasted change in December 2015 versus December 2014 unbilled volumes to the 2015 UAF forecast. As such, the 2015 Test Year UUF forecast is as follows:

2015 UUF = (Forecast of UAF Gas) + (Change in Unbilled Gas)
= (Forecast of UAF Gas) + (Forecast of December 2015 Unbilled Gas - Forecast for December 2014 Unbilled Gas)
= 81,519 10^3m^3 + (719,794 10^3m^3 – 704,606 10^3m^3)
= 81 519 10^3m^3 + 15,188 10^3m^3
= 96,707 10^3m^3

Witnesses: H. Sayyan
M. Suarez

SUMMARY OF GAS COST TO OPERATIONS
YEAR ENDED DECEMBER 31, 2015

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	0.0	0.0	0.000	0.000
1.2	Western - @ Empress - TCPL	1,332,460.5	190,796.8	143.191	3.799
1.3	Western - @ Nova - TCPL	2,570,285.3	361,739.7	140.739	3.734
1.4	Western Buy/Sell - with Fuel	1,133.1	163.0	143.834	3.816
1.5	Western - @ Alliance	879,449.9	128,991.0	146.672	3.892
1.6	Less TCPL Fuel Requirement	(150,375.9)	0.0		
1.	Total Western Canadian Supplies	4,632,952.9	681,690.5	147.140	3.904
2.	Peaking Supplies	7,750.7	7,711.3	994.925	26.398
3.	Ontario Production	730.0	142.3	194.991	5.174
4.	Chicago Supplies	1,843,671.0	298,671.1	161.998	4.298
5.	Delivered Supplies	700,451.1	169,688.1	242.256	6.428
6.	Niagara Supplies	323,693.3	53,936.8	166.629	4.421
7.	Total Supply Costs	7,509,249.0	1,211,840.2	161.380	4.282
	Transportation Costs				
8.1	TCPL - FT - Demand		226,915.7		
8.2	- FT - Commodity	3,753,503.0	0.0	-	-
8.3	- Parkway to CDA		3,410.5		
8.4	- STS - CDA		12,924.1		
8.5	- STS - EDA		9,436.8		
8.6	- Dawn to CDA		8,505.7		
8.7	- Dawn to EDA		18,173.0		
8.8	- Dawn to Iroquois		6,129.2		
8.9	Other Charges		0.0		
8.10	Nova Transmission		19,159.9		
8.11	Alliance Pipeline		41,951.8		
8.12	Vector Pipeline		27,126.1		
8.13	Niagara Falls to Enbridge Parkway CDA		2,114.1		
8.	Total Transportation Costs		375,846.8		
9.	Total Before PGVA Adjustment	7,509,249.0	1,587,687.1	211.431	5.610
10.	PGVA Adjustment		(53,598.5)		
11.	Total Purchases & Receipt	7,509,249.0	1,534,088.6	204.293	5.420

SUMMARY OF GAS COST TO OPERATIONS
YEAR ENDED DECEMBER 31, 2015

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)
11.	Total Purchases & Receipt	7,509,249.0	1,534,088.6	204.293	5.420
12.	Storage Fluctuation	(63,576.4)	(12,988.2)		
13.	Commodity Cost to Operations	7,445,672.6	1,521,100.4	204.293	
14.	Storage and Transportation Costs		105,009.1		
15.	Gas Cost to Operations	7,445,672.6	1,626,109.4	218.397	5.795
16.	T-Service Transportation Costs		60,986.7		
17.	Forecasted Gas Costs	7,445,672.6	1,687,096.2	226.587	6.012

RECONCILIATION OF NATURAL GAS SENDOUT VOLUMES
TO SALES VOLUMES
YEAR ENDED DECEMBER 31, 2015

Item #		
1.	Sendout To Operations	7,445,672.6
2.	T-Service Volumes	3,829,911.8
3.	Total Sendout	11,275,584.4
4.1	Residential Sales	4,197,447.8
4.2	Commercial Sales	2,550,293.2
4.3	Industrial Sales	448,527.4
4.4	T-Service	3,782,996.6
4.5	Rate 200 T-Service (Gazifere)	42,979.2
4.6	Rate 200 Sales (Gazifere)	126,107.5
4.7	Company Use	6,762.0
4.8	Unaccounted For (UAF)	81,519.0
4.9	Unbilled Forecast - Sales	11,252.1
4.10	Unbilled Forecast - T-Service	3,936.0
4.11	Lost and Unaccounted For (LUF)	23,763.6
4.	Total System Requirements	11,275,584.4

SUMMARY OF STORAGE & TRANSPORTATION COSTS
FISCAL 2015

Item #	Units - $(000)	Col. 1 Storage & Transportation Charges Incurred in Fiscal 2015	Col. 2 Fiscal 2015 Storage Charges Recovered in Fiscal 2015	Col. 3 Fiscal 2014 Storage Charges Recovered in Fiscal 2015	Col. 4 Total Storage & Transportation Charges Recovered in Fiscal 2015
	Storage				
1.1	Chatham D	152.1	87.7	77.5	165.2
1.2	Injection	88.6	26.6	375.0	401.6
1.3	Withdrawal	74.8	74.8	0.0	74.8
1.4	Market Based Storage	13,822.0	8,194.9	7,579.0	15,773.9
1.5	Unutilized Transportation Costs	0.0	0.0	0.0	0.0
1.6	Other	2,264.0	1,475.4	295.5	1,770.9
1.	Total Storage	16,401.4	9,859.4	8,327.0	18,186.3
2.	Total Transportation	70,365.6	39,059.8	30,830.3	69,890.1
	Dehydration				
3.1	Demand	1,022.7	573.9	465.0	1,038.8
3.2	Commodity	220.2	220.2	0.0	220.2
3.	Total Dehydration	1,242.9	794.0	465.0	1,259.0
4.	Total Storage & Other Costs	88,009.9	49,713.2	39,622.2	89,335.4
	Fuel Costs				
5.1	Tecumseh	2,972.4	1,940.6	1,630.3	3,570.9
5.2	Union Storage	1,166.5	599.7	447.9	1,047.6
5.3	Union Transportation	10,498.8	10,158.3	896.8	11,055.1
5.	Total Fuel Costs	14,637.8	12,698.7	2,975.0	15,673.6
6.	Unutilized Transportation Costs	0.0	0.0	0.0	0.0
7	Total Storage & Transportation	102,647.7	62,411.9	42,597.2	105,009.1
8.	Storage and Transportation Costs Charged to Gas Cost to Operations				105,009.1

	2014 Budget Peak Day Demand	Column 1	Column 2	Column 3	2015 Budget Peak Day Demand	Column 4	Column 5	Column 6
Item #	GJ's	CDA	EDA	Total	GJ's	CDA	EDA	Total
1.	Demand	3,288,088	673,262	3,961,350	Demand	3,303,548	674,042	3,977,590
2.	Less Curtailment	(133,995)	(28,705)	(162,700)	Less Curtailment	(83,874)	(33,259)	(117,133)
3.	Net Peak Day Demand	3,154,093	644,557	3,798,650	Net Peak Day Demand	3,219,674	640,783	3,860,457
4.	TCPL FT Capacity	271,468	370,627	642,095	TCPL FT Capacity	404,538	390,627	795,165
5.	TCPL STFT	-	-	-	TCPL STFT	-	-	-
6.	TCPL Short Haul	151,818	114,000	265,818	TCPL Short Haul	158,720	114,000	272,720
7.	TCPL STS	369,464	80,611	450,075	TCPL STS	369,465	80,611	450,076
8.	Ontario T-Service	300,354	26,576	326,930	Ontario T-Service	243,353	5,718	249,071
9.	Union Deliveries	1,775,027	-	1,775,027	Union Deliveries	1,775,027	-	1,775,027
10.	Delivered Service	182,738	-	182,738	Delivered Service	167,739	-	167,739
11.	Peaking Service	105,505	52,753	158,258	Peaking Service	105,506	52,754	158,260
12.	Total Supply	3,156,374	644,567	3,800,941	Total Supply	3,224,348	643,710	3,868,058
13.	Sufficency/(Deficiency)	2,281	10	2,291	Sufficency/(Deficiency)	4,674	2,927	7,601

MONTHLY PRICING INFORMATION

	Col. 1 21 Day Average Empress CGPR	Col. 2 21 Day Average NYMEX	Col. 3 21 Day Average Chicago	Col. 4 21 Day Average US Exchange	Col. 5 $CAD/$10^3m^3$ Equivalent (Note 1)
	$CAD/GJ	$US/MMBtu	$US/MMBtu	$CAD/$US	
Jan-15	4.0067	4.1603	4.4921	1.0968	
Feb-15	3.9852	4.1480	4.4719	1.0977	
Mar-15	3.8766	4.0730	4.3172	1.0984	
Apr-15	3.5392	3.8273	3.8685	1.0992	
May-15	3.5054	3.8102	3.8064	1.1000	
Jun-15	3.4904	3.8410	3.8398	1.1007	
Jul-15	3.5219	3.8760	3.8731	1.1014	
Aug-15	3.5278	3.8834	3.8767	1.1020	
Sep-15	3.5239	3.8704	3.8635	1.1028	
Oct-15	3.6182	3.8968	3.8798	1.1035	
Nov-15	3.8044	3.9853	4.1338	1.1041	
Dec-15	3.9271	4.1376	4.3340	1.1047	
	3.6939	3.9591	4.0631	1.1010	139.2231
TCPL Fuel Ratio		4.01%			144.8025

(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 **1-Aug-14** **to** **29-Aug-14**

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

GAS SUPPLY/DEMAND BALANCE

Item #		Col. 1 2015 Budget 10^3m^3	Col. 2 2014 Budget 10^3m^3	Col. 3 2013 Actual 10^3m^3
1.	Total Demand	11,275,584.4	11,232,185.0	12,177,237.6
	Deliveries			
2.1	Western Canadian Supplies	4,632,952.9	4,753,749.3	3,585,652.2
2.2	Peaking/Seasonal	7,750.7	36,068.0	10,611.7
2.3	Ontario Production	730.0	730.0	453.9
2.4	Chicago Supplies	1,843,671.0	1,847,142.8	1,784,446.2
2.5	Delivered Supplies	700,451.1	932,827.1	2,367,941.5
2.6	Niagara Supplies	323,693.3	-	-
2.7	Direct Purchase Delivery	3,823,270.8	3,742,271.6	4,530,226.3
2.8	Storage (Injection)/Withdrawal	(56,935.4)	(80,603.8)	(102,094.2)
2.	Total Delivery	11,275,584.4	11,232,185.0	12,177,237.6

Total Demand includes both System Sales and T-Service Consumption

2015 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 and EB-2012-0459 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 of 7.

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.

Witnesses: D. McIlwraith
R. Small

6. This Application includes the implementation of the EB-2011-0226 Board-approved CC/CIS Settlement Agreement for 2015, and replaces the 2015 placeholder amounts presented in EB-2012-0459. Exhibit D1, Tab 3, Schedule 3 provides an updated 2015 CC/CIS Template, in which Enbridge has updated the 2015 forecast number of customers shown at Row 25, Column J, as compared to the previously updated Template filed within EB-2012-0459, at Exhibit D1, Tab 10, Schedule 3, which included a 2015 placeholder forecast number of customers. The resulting updated annual Total CIS and Customer Care costs and Allowed Revenue for 2015 are shown on Lines 26 and 27 of the updated Template. The updated 2015 costs, of $119.1 million are calculated by multiplying the Board-approved Total cost/Customer of $56.41 (updated Template, Row 17a, Column J) by Enbridge's updated forecast of "customers" for 2015, of 2,112,148 (updated Template, Row 25, Column J). The updated 2015 Allowed Revenue amount, of $118.0 million, is calculated by multiplying the Board-approved 2015 Normalized Customer Care Revenue Requirement per customer, of $55.88 (updated Template, Row 24, Column J), by the updated forecast of "customers" for 2015, again 2,112,148.

7. As a result of updating the 2015 forecast number of customers, the updated Total CIS and Customer Care costs of $119.1 million, and corresponding Allowed Revenues of $118.0 million, are each $0.7 million lower than the 2015 placeholder amounts of $119.8 million and $118.7 million. The 2015 placeholder amounts were calculated within EB-2012-0459 at Exhibit D1, Tab 10, Schedule 3, Rows 26 and 27, Column J, and utilized within the 2015 placeholder allowed revenue and sufficiency/deficiency determination (EB-2012-0459 Decision and Rate Order, Appendix A, page 9 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 updated 2015 test year allowed revenues and sufficiency/(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 2015 rates, is an increase (deficiency) of approximately $3.9 million as compared to the 2014 approved Customer Care and CIS Allowed Revenues included in 2014 rates, or 2015 revenues at existing rates. This can be seen by comparing the updated 2015 Allowed Revenue of $118.0 million, shown in the updated Template at Exhibit D1, Tab 3, Schedule 3, Row 27, Column J, to the 2014 approved Allowed Revenue of $114.1 million, also shown in the updated Template at Exhibit D1, Tab 3, Schedule 3, Row 27, Column I. This increase is also reflected in the 2015 Test Year Allowed Revenue and Sufficiency/(Deficiency) calculation shown at Exhibit F1, Tab 2, Schedule 1, Row 28, Column 7.

SETTLEMENT AGREEMENT

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

September 2, 2011

TABLE OF CONTENTS

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

---

[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 not 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

[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.

---

[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

---

[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.

[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.

---

[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

[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.

---

[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	

"Updated CIS / CC Template for 2015"

#	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 customer forecasts for 2015 (2013 and 2014 are Board Approved customer forecasts and 2016 - 2018 are placeholders from EB-2012-0459)**								**2,059,959**	**2,086,534**	**2,112,148**	**2,163,168**	**2,202,848**	**2,242,859**	
26	**Updated Line 16 Total CIS & Customer Care costs**								**$ 114,842,714**	**$ 117,011,324**	**$ 119,147,334**	**$ 122,746,125**	**$ 125,735,997**	**$ 128,775,910**	
27	**Updated Line 23 Total Customer Care Revenue by year**								**$ 110,207,807**	**$ 114,084,283**	**$ 118,024,255**	**$ 123,533,214**	**$ 128,565,544**	**$ 133,779,203**	

2015 DSM FORECAST BUDGET

1. Enbridge is currently operating in the final year of a three-year DSM Framework which began in 2012 and will conclude at end of 2014. The Board approved DSM budget for 2014 is $32.2 million (EB-2012-0394). For the purposes of the Company's Custom IR Rates application (EB-2012-0459) which applies to the years 2014 through 2018, Enbridge started with the Board approved DSM Budget for 2014, inflated this amount by the GDP-IPI to $32.8 million and included this amount as a placeholder for 2015 given that the actual DSM budget for 2015 would be approved in a separate application process following the Board's completion of its consultation into the next generation of the DSM Framework (EB-2014-0134, the "Framework Consultation").

2. 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 2015-2018 to those annual amounts approved within the EB-2014-0134 DSM Framework consultation. Any variance between the final approved DSM amount included within each of the year's 2015 to 2018 Allowed Revenue and the actual DSM amounts incurred will be recorded in the DSMVA.

.

3. The Framework Consultation will result in a new DSM Framework that will apply to the six years 2015 through 2020. While the Company and DSM stakeholders recently filed submissions on the Board's draft DSM Framework and Guideline released on September 15, 2014, a final decision of the Board on the new DSM Framework is not expected until later this year. The timing of the Board's decision on the Framework Consultation creates some uncertainty and complexity from a

planning process perspective for 2015. Despite this, the Company has developed a 2015 DSM budget it believes recognizes directionally the likely result of the Framework Consultation and reflects the practicalities of the planning process for DSM programs that will be operated in 2015. Enbridge is therefore proposing an increase in the DSM Budget for 2015 to $35 million which is an increase of approximately 8.7% over the Board approved 2014 DSM budget.

4. The increase in the filed budgets from $32.8 to $35 million for 2015 results from direction ascertained from two notable milestones on the evolution of DSM beyond the current DSM Framework. These milestones included: 1) the Minister of Energy's Directive to the Board outlining the requirement for a six-year plan and achievement of all cost-effective DSM; and, 2) the Draft DSM Framework and Guidelines released by the Board on September 15, 2014 outlining preliminary guidance on the level of budget for consideration between 2015 and 2020. Additional monies allocated to DSM in 2015 will be used towards expanded programs and expanded reach of programs likely in the Rate 1 residential area.

5. As set out at Exhibit D1, Tab 1, Schedule 2, the updated 2015 DSM Budget has been included within Operations and Maintenance costs for the determination of final 2015 Allowed Revenue.

PENSION / OPEB 2015 UPDATED FORECAST

1. Within the EB-2012-0459 Decision with Reasons, the Board determined that for each of the years 2015-2018, Pension & OPEB expense within Operations & Maintenance costs was 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 years. The updated Test Year Allowed Revenue replaces the 2015 placeholder Allowed Revenue information which was filed at Appendix A, pages 9 to 16 within the Board's Decision and Rate Order in EB-2012-0459.

2. EGD uses Mercer Canada Limited ("Mercer"), to review, update and forecast its required annual Pension and OPEB accrual expense and cash requirement. The 2015 annual Pension and OPEB accrual expense, as provided by Mercer, is forecasted at $37.3 million; shown as "P&L Charge (Credit)" within the Mercer Reports. Mercer's Reports are attached as Appendix 1 and 2 of this Exhibit.

3. The 2015 forecasted annual Pension and OPEB accrual expense is comprised of the following:

	Plan	2015 Forecasted Amount
1.	EGD RPP Plan	$28.7 million
2.	EGD SERP Plan	$0.5 million
3.	EGD SSERP Plan	($0.1 million)
4.	EGD's portion of Enbridge Inc.'s RPP Plan	($0.1 million)
5.	EGD's portion of Enbridge Inc.'s SPP Plan	$1.5 million
6.	DC Plan (included within the EGD RPP line of Appendix A to the Mercer Report)	$1.0 million
7.	OPEB Plan	$5.8 million
	Total Pension and OPEB expense	$37.3 million

Witnesses: J. Barradas
J. Shem

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 F1, Tab 3, Schedule 1.

Witnesses: J. Barradas
J. Shem

Scott Thompson
Senior Associate

222 - 3rd Avenue SW, Suite 1200
Calgary, Alberta T2P 0B4
+1 403 476 3212
Fax +1 403 261 6938
scott.thompson@mercer.com
www.mercer.ca

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

3 October 2014

Subject: Enbridge Gas Distribution Inc. Estimated 2015 Pension and Benefit Expense and Cash Contributions – Updated Based on 2014 Discretionary Contribution and Market Conditions as at September 30, 2014

Dear Jason,

At your request we have updated our previous estimate of Enbridge Gas Distribution Inc.'s ("EGDI") share of pension and benefits expense and cash contributions in 2015 for the following pension and non-pension post retirement plans:

- Pension Plan for Employees of Enbridge Gas Distribution Inc. and Affiliates (the "EGD RPP");

- Supplemental Executive Retirement Plan of Enbridge Gas Distribution (the "SERP");

- Supplementary Senior Executive Retirement Plan of Enbridge Gas Distribution Inc. (the "SSERP"); and

- Non-pension Post Retirement Plan for Employees of Enbridge Gas Distribution Inc. (the "OPEB Plan").

This letter replaces our projections previously provided August 29, 2014. The purpose of the current update is to reflect EGDI's recently approved discretionary contribution of $16,923,682 to the EGD RPP which will occur before the end of 2014. We have also updated our projection to capture market experience up to September 30, 2014.

MERCER

We have used the same calculation basis and assumptions as were used in our previous estimate except for the following:

- We reflected an additional discretionary contribution of $16,923,682 to the EGD RPP by EGDI.

- We used an accounting discount rate of 4.20% at September 30, 2014 (as compared to 4.30% at June 30, 2014).

- We extrapolated the market value of assets to December 31, 2014 based on the actual market value of assets at August 31, 2014 and market index returns to September 30, 2014 (as compared to the previous estimate which used an extrapolation based on the actual market value of assets at June 30, 2014).

Actual pension and benefits expense and cash funding requirements in respect of 2015 may differ from the amounts estimated here, and will be based on future economic and demographic experience.

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 filing with the OEB. This information is not intended or suitable for any other purpose.

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

Appendix A – Summary of estimated 2015 US GAAP pension expense for EGDI's share of the EGD RPP, SERP, SSERP and OPEB Plan.

Appendix B – Summary of EGDI's estimated 2015 contributions to the EGD RPP, SERP, SSERP and OPEB Plan.

Appendix C contains important notices relevant to these projections.

MERCER

BASIS OF ACCOUNTING PROJECTIONS

We have projected the results of the December 31, 2013 actuarial valuations of the pension plans for US GAAP financial reporting purposes forward to 2014. We have not updated the membership data as at December 31, 2013 to reflect demographic changes since that date. We have projected the results of the September 30, 2012 actuarial valuations of the OPEB Plan for US GAAP financial reporting purposes forward to 2014. The purpose of these projections is to estimate the accrual costs in 2015.

Under US GAAP, with the exception of the discount rate, assumptions are selected by Enbridge and are referred to as “management's best estimates”. The discount rate must be chosen by reference to the market yields on high quality corporate bonds. Assumptions used in these projections are the same as assumptions effective December 31, 2013 with the following exceptions:

Assumption	**Current Assumptions – As at September 30, 2014**	**Prior Assumptions – As at December 31, 2013**
Discount rate	4.20%	5.00%
Mortality	RPP 2014 Mortality Tables with generational improvements using CPM Scale B with no pension size adjustments	Preliminary RPP 2014 Mortality Tables with generational improvements using CPM Scale A with pension size adjustments[1]

Actual assumptions to be used at December 31, 2014 will be reviewed in the final quarter of 2014 by Enbridge and may be different than assumptions used for these projections.

All other assumptions, policies, methods and plan provisions are the same as those summarized in our ASC 715 (US GAAP) Actuarial Valuation Report as at December 31, 2013 Consolidated Total for All Enbridge Gas Distribution Inc. Plans dated February 3, 2014 (“Pension Report”) and our ASC 715 (US GAAP) Actuarial Valuation Report as at December 31, 2013 for Enbridge Gas Distribution Inc. Non-Pension Post Retirement Plan dated February 11, 2014 (“OPEB Report”).

[1] 100% pension size adjustment for the EGD RPP and 80% pension size adjustment for the SERP and SSERP.

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 financial statements obtained from their online reporting tool Workbench. The market value of assets as at August 31, 2014 was extrapolated to December 31, 2014 using:

- Contributions in accordance with minimum funding requirements;
- An additional discretionary contribution of $16,923,682 to the EGD RPP;
- Estimated benefit payments based on amounts paid between January and August;
- Expected returns in September based on market index returns; and
- Expected returns from October 1, 2014 to December 31, 2014 based on the long-term return assumptions (6.35% for the EGD RPP and 3.20% for the SERP and SSERP).

As directed by you, we have reflected the economic conditions as at September 30, 2014.

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 conducted and filed with FSCO and the CRA as at December 31, 2013. Contributions to the EGD RPP by EGDI and other participating employers must be made in accordance with this valuation until a new valuation is filed with the regulators (no later than December 31, 2016). Based on this valuation, EGDI and the other participating employers are permitted to apply a going concern excess to reduce DB and DC contributions in 2015 and 2016. As such, we have estimated that no contributions will be made to the EGD RPP in 2015.

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 policy.

MERCER

2015 SERP contributions were determined by extrapolating the December 31, 2013 actuarial funding valuations to December 31, 2014. Extrapolations were performed without any changes to the data, assumptions, liability methods or provisions. For the purposes of determining the funding position, assets were extrapolated using the methods described in the previous section.

2015 SSERP contributions are assumed to be nil. Due to the funded status of the plan as at December 31, 2013, no contributions are expected in 2015.

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,

Scott Thompson
Senior Associate

Copy:
Ryan Stelmaschuk, Enbridge Inc.
Joe De Dominicis, Mercer
Danielle Neville, Mercer
Laurie Alook, Mercer
Nick Gubbay, Mercer

\\caclg11fp04.mercer.com\clg_data\data\client\retire\enbridge\2014\special projects\egd regulatory projections\egd accrual costs\revised to reflect sep 30 market conditions\js - egdi 2015 estimated pension expense and contributions letter - sep 30.docx

Appendix A

MERCER

Enbridge Gas Distribution Inc.

EGDI 2015 US GAAP Pension and OPEB Expense Projections - UPDATED

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)
2015	1.02	29.11	39.12	-59.28	19.76	-	29.73

EGD 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)
2015	-	0.64	-0.54	0.41	-	0.51

EGD 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)
2015	-	0.17	-0.25	-	-	-0.08

EGDI Only Portion of OPEB

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)
2015	1.27	4.40	-	0.01	0.10	5.78

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)
2015	1.02	30.38	44.33	-60.07	20.18	0.10	35.94

Appendix B

MERCER

Enbridge Gas Distribution Inc.

EGDI 2015 Cash Contribution Projections - UPDATED

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

	EGDI Only Portion of EGD RPP			EGD SERP	EGD SSERP	EGDI Only Portion of OPEB	TOTAL EGDI
Year	DB Current Service Cost*	DC Current Service Cost*	Going Concern and Solvency Special Payments	Solvency Special Payments**	Solvency Special Payments**	Total Annual Employer Contributions	Total Annual Employer Contributions
2015	-	-	-	0.09	-	4.12	4.21

* Assumes that Enbridge elects to utilize the going concern excess revealed in the December 31, 2013 valuation filed with FSCO and CRA to cover both DB and DC current service cost

** Special payments are calculated and updated annually

MERCER

Appendix C

IMPORTANT NOTICES

Mercer has prepared this letter exclusively for EGDI for filing with 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 valuation results shown in the Report on the Actuarial Valuation as at December 31, 2013 for the EGD RPP, the Executive Summary of Valuation Results at December 31, 2013 for the SERP and SSERP, and from accounting valuation results shown in the ASC 715 (US GAAP) Actuarial Valuation Report as at December 31, 2013 for Enbridge Gas Distribution Inc. Non-Pension Post Retirement Plan dated February 11, 2014 (the “2013 Reports”). The results are subject to the same Important Notices and qualifications described in the 2013 Reports except as specifically noted in this letter. The 2013 Reports are incorporated by reference into this letter, and are essential to understanding these results. If you do not have copies of the 2013 Reports, please let us know immediately.

The accounting projections are based on the same actuarial assumptions used in the 2013 Reports for funding purposes, except for the following assumptions:

Assumption	Current Accounting Assumptions	Assumptions in 2013 Reports
Discount rate	4.20%	5.50% - EGD RPP 3.20% - SERP & SSERP 5.00% - OPEB Plan
Mortality	RPP 2014 Mortality Tables with generational improvements using CPM Scale B with no pension size adjustments	Preliminary RPP 2014 Mortality Tables with generational improvements using CPM Scale A with pension size adjustments[2]

Our extrapolation reflects a single scenario from a range of possibilities. However, the future is uncertain, and the plan’s 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. There were no changes in the actuarial methods used in the 2013 Reports.

[2] Change in assumption is applicable only to the OPEB Plan. The EGD RPP, SERP and SSERP actuarial valuations for funding purposes referenced in the reports were based on the RPP 2014 Tables with generational improvements using CPM Scale B.

MERCER

The results shown in this letter are based on the membership data used in the 2013 Reports with the following adjustments since December 31, 2013:

- Actual benefit payments to August 31, 2014 based on the CIBC Mellon monthly financial statements; and

- Estimated benefit payments between September 1, 2014 and December 31, 2014 based on actual benefit payments to August 31, 2014 as per the CIBC Mellon monthly financial statements.

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, 2013.

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.

MERCER

Enbridge Gas Distribution Inc.

EGDI's Share of the EI RPP and EI SPP

2015 Pension Expense and Cash Contributions ($Millions)

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

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)
2015	0.0	0.3	(0.5)	0.1	0.0	(0.1)

EGDI Only Portion of EI SPP*						
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)
2015	1.5	0.6	(0.9)	0.3	0.0	1.5

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

EGDI Only Portion of EI RPP			
Year	Current Service Cost	Solvency Special Payments	Total Annual Employer Contributions
2015	-	0.3	0.3

EGDI Only Portion of EI SPP			
Year	Current Service Cost*	Wind-up Special Payments	Total Annual Employer Contributions
2015	1.1	-	1.1

Assumptions

Discount rate	4.20%
Expected return on assets	EI RPP - 7.00%
	EI SPP - 5.40%
Salary scale	4.00%

* Does not reflect assets in the Canadian Grantor Trust

** Includes contributions to the Canadian Grantor Trust

MERCER

Enbridge Gas Distribution Inc.
EGDI's Share of the EI RPP and EI SPP
Important Notices

Mercer has prepared these 2015 US GAAP pension expense and 2015 contribution estimates exclusively for Enbridge Gas Distribution Inc. These results 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 exhibits are extrapolated from accounting valuation results shown in the ASC 715 (US GAAP) Report on the Actuarial Valuation as at December 31, 2013 for Enbridge Inc. and Affiliates (the "2013 Report"), and are subject to the same Important Notices and qualifications described in the 2013 Report except as specifically noted in this exhibit. The 2013 Report is incorporated by reference into this exhibit, and is essential to understanding these results. If you do not have a copy of the 2013 Report, please let us know immediately.

These exhibits are based on the actuarial assumptions used in the 2013 Report , except that the discount rate has been decreased to 4.20% and the mortality assumption has been updated to reflect the RPP 2014 Table with generational improvements using CPM Scale B. Our extrapolation reflects a single scenario from a range of possibilities. However, the future is uncertain, and the plan's actual experience will likely differ from the assumptions utilized and the scenarios presented; these differences may be significant or material. This exhibit is presented at a particular point in time and should not be viewed as a prediction of the plan's future financial condition or its ability to pay benefits in the future. There were no changes in the actuarial methods used in the 2013 Report.

The results shown in this exhibit are based on the membership data used in the 2013 Report assuming no changes since December 31, 2013.

The results shown in this exhibit are based on plan provisions provided by the plan administrator. There were no changes made to the plan provisions since December 31, 2013.

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.

2015 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 sufficiency/(deficiency) amounts, between the 2015 placeholder amounts (EB-2012-0459) and the updated 2015 Test Year amounts presented within this proceeding. The calculation of the updated 2015 Test Year utility taxable income and income tax, and the change from 2015 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 decreased by $49.6 million, from $336.7 million in the 2015 placeholder, to $287.1 million in the updated 2015 Test Year. The decrease 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. Revenues have been updated to reflect the impact of the updated 2015 volume forecast and October 1, 2014 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 2015 volume forecast, updated 2015 gas supply plan, October 1, 2014 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 sufficiency/(deficiency) excluding CIS and Customer Care impacts to be calculated.

Witness: R. Small

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 $10.2 million reduction in taxable income (Rows 18 and 19 of Exhibit D1, Tab 6, Schedule 2) and corresponding $2.6 million reduction in income tax expense (Rows 22 to 24 of Exhibit D1, Tab 6, Schedule 2).

5. Utility income tax is further reduced by $0.4 million as a result of lower part VI.1 tax (Rows 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 rate base resulting from the 2015 volumes, gas supply plan, and pricing updates, which are detailed in the B series of

exhibits, and a lower return component of debt which has been updated to reflect the impact of actual debt issuances and updated 2015 forecast issuances and cost rates, as identified in the E series of exhibits. The net impact is a $0.8 million reduction in the tax shield on interest expense.

7. The combined impact of all the above mentioned updates is a $2.2 million reduction in the updated 2015 Test Year utility income tax expense, excluding CIS and Customer Care impacts, and excluding any taxes on gross sufficiency/(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.

CALCULATION OF UTILITY TAXABLE INCOME AND INCOME TAX EXPENSE
2015 UPDATED FORECAST

Line No.		Col. 1 Excl. CIS EB-2012-0459 2015 Utility Placeholder Tax	Col. 2 2015 Test Year Update Adjustments	Col. 3 Excl. CIS 2015 Updated Test Year Utility Tax
		($Millions)	($Millions)	($Millions)
1.	Utility income before income taxes	336.7	(49.6)	287.1
	Add			
2.	Depreciation and amortization	249.0	-	249.0
3.	Accrual based pension and OPEB costs	33.8	3.5	37.3
4.	Other non-deductible items	1.1	-	1.1
5.	Total Add Back	283.9	3.5	287.4
6.	Sub total	620.6	(46.1)	574.5
	Deduct			
7.	Capital cost allowance - Federal	282.2	-	282.2
8.	Capital cost allowance - Provincial	282.2	-	282.2
9.	Items capitalized for regulatory purposes	46.8	-	46.8
10.	Deduction for "grossed up" Part VI.1 tax	4.2	(0.6)	3.6
11.	Amortization of share/debenture issue expense	3.3	(2.3)	1.0
12.	Amortization of cumulative eligible capital	5.6	-	5.6
13.	Amortization of C.D.E. and C.O.G.P.E	0.4	-	0.4
14.	Site restoration cost adjustment	90.4	-	90.4
15.	Cash based pension and OPEB costs	39.6	(33.0)	6.6
16.	Total Deduction - Federal	472.5	(35.9)	436.6
17.	Total Deduction - Provincial	472.5	(35.9)	436.6
18.	Taxable income - Federal	148.1	(10.2)	137.9
19.	Taxable income - Provincial	148.1	(10.2)	137.9
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	22.2	(1.5)	20.7
23.	Income tax provision - Provincial	17.0	(1.1)	15.9
24.	Income tax provision - combined	39.2	(2.6)	36.6
25.	Part V1.1 tax	1.4	(0.4)	1.0
26.	Total taxes excluding tax shield on interest expense	40.6	(3.0)	37.6
	Tax shield on interest expense			
27.	Rate base	4,801.9	109.5	4,911.4
28.	Return component of debt	3.31%	-0.13%	3.18%
29.	Interest expense	159.1	(2.9)	156.2
30.	Combined tax rate	26.50%	0.00%	26.50%
31.	Income tax credit	(42.2)	0.8	(41.4)
32.	Total income taxes	(1.6)	(2.2)	(3.8)

DEFERRAL AND VARIANCE ACCOUNTS

2014 Approved Deferral and Variance Accounts

1. The following list identifies EGD's 2014 Board Approved deferral and variance accounts ("DA" and "VA"). For the 2014 deferral and variance accounts approved and listed below, EGD 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 2014 year-end financial results (around April 2015).

2014 Purchased Gas Variance Account ("PGVA"),
2014 Design Day Criteria Transportation Deferral Account ("DDCTDA"),
2014 Unabsorbed Demand Cost Deferral Account ("UDCDA"),
2014 Transactional Services Deferral Account ("TSDA"),
2014 Unaccounted for Gas Variance Account ("UAFVA"),
2014 Storage and Transportation Deferral Account ("S&TDA")
2014 Deferred Rebate Account ("DRA"),
2014 Customer Care CIS Rate Smoothing Deferral Account ("CCCISRSDA"),
2014 Average Use True Up Variance Account ("AUTUVA"),
2014 Manufactured Gas Plant Deferral Account ("MGPDA"),
2014 Gas Distribution Access Rule Impact Deferral Account ("GDARIDA"),
2014 Electric Program Earnings Sharing Deferral Account ("EPESDA"),
2014 Open Bill Revenue Variance Account ("OBRVA"),
2014 Ex-Franchise Third Party Billing Services Deferral Account ("EFTPBSDA"),
2014 Post-Retirement True-Up Variance Account (PTUVA"),
2014 Transition Impact of Accounting Changes Deferral Account ("TIACDA"),
2014 Demand-Side Management Variance Account ("DSMVA"),
2014 Lost Revenue Adjustment Mechanism Variance Account ("LRAM"),

Witness: R. Small

2014 Demand Side Management Incentive Deferral Account (“DSMIDA”),
2014 Earnings Sharing Mechanism Deferral Account (“ESMDA”),
2014 Customer Care Services Procurement Deferral Account (“CCSPDA”),
2014 Greenhouse Gas Emissions Impact Deferral Account (“GGEIDA”),
2014 Constant Dollar Net Salvage Adjustment Deferral Account (“CDNSADA”),
2014 Rider E Deferral Account (“REDA”).

2015 Approved and Proposed Deferral and Variance Accounts

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 have been approved for 2015.

2015 Purchased Gas Variance Account (“PGVA”),
2015 Transactional Services Deferral Account (“TSDA”),
2015 Unaccounted for Gas Variance Account (“UAFVA”),
2015 Storage and Transportation Deferral Account (“S&TDA”),
2015 Deferred Rebate Account (“DRA”),
2015 Customer Care Services Procurement Deferral Account (“CCSPDA”),
2015 Customer Care CIS Rate Smoothing Deferral Account (“CCCISRSDA”),
2015 Average Use True Up Variance Account (“AUTUVA”),
2015 Greenhouse Gas Emissions Impact Deferral Account (“GGEIDA”),
2015 Earnings Sharing Mechanism Deferral Account (“ESMDA”)
2015 Manufactured Gas Plant Deferral Account (“MGPDA”),
2015 Gas Distribution Access Rule Impact Deferral Account (“GDARIDA”),
2015 Electric Program Earnings Sharing Deferral Account (“EPESDA”),
2015 Open Bill Revenue Variance Account (“OBRVA”),
2015 Ex-Franchise Third Party Billing Services Deferral Account (“EFTPBSDA”),

2015 Constant Dollar Net Salvage Adjustment Deferral Account (“CDNSADA”),
2015 Transition Impact of Accounting Changes Deferral Account (“TIACDA”),
2015 Post-Retirement True-Up Variance Account (“PTUVA”),
2015 Greater Toronto Area Incremental Transmission Capital Revenue Requirement Deferral Account (“GTAITCRRDA”)
2015 Demand-Side Management Variance Account (“DSMVA”),
2015 Lost Revenue Adjustment Mechanism Variance Account (“LRAM”),
2015 Demand Side Management Incentive Deferral Account (“DSMIDA”).

3. Within the EB-2014-0323 proceeding, the Board approved the establishment of the following account:

2015 Dawn Access Costs Deferral Account (“DACDA”)

4. In addition to the accounts which have been previously approved, the Company requests that the following accounts also be established for use during 2015.

2015 Unabsorbed Demand Cost Deferral Account (“UDCDA”),
2015 Credit Final Bill Deferral Account (“CFBDA”).

5. The criteria adopted by the Company in determining to request the establishment of the additional deferral accounts above included the following considerations:
- 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 2015, EGD will file a separate application(s) requesting a process for the review and proposed clearance of the 2015 deferral and variance accounts as soon as feasibly possible following the public release of its fiscal year-end financial results (around April of 2016).

Descriptions of Accounts

2015 Purchased Gas Variance Account ("2015 PGVA")

7. The purpose of the 2015 PGVA is to record the effect of price variances between actual 2015 gas purchase prices and the forecast prices that underpin the revenue rates to be charged in 2015. 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.

2015 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 transportation tolls for the Alliance and Vector 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, 2015, expenditures related to TCPL's Storage Transportation Services, including balancing fees related to TCPL's Limited Balancing Agreement, will be recorded in the 2015 PGVA. The 2015 PGVA will also record amounts related to a Limited Balancing Agreement with Union Gas.

Witness: R. Small

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 2015 PGVA and 2015 TSDA for purposes of deferral account dispositions.

15. In addition, the 2015 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 2015 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 2015 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 2015 PGVA using the Board Approved EB-2006-0117 interest rate methodology.

2015 Transactional Services Deferral Account ("2015 TSDA")

21. The purpose of the 2015 TSDA is to record the incremental ratepayer share of net revenue from transportation and storage related Transactional Services, to be shared 90/10 between EGD's ratepayers and shareholders.

22. In the event that the ratepayer share of 2015 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 2015 TS net revenue is less than $12.0 million, then EGD will be credited with the difference between the actual ratepayer share of 2015 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 2015 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.

<u>2015 Unaccounted for Gas Variance Account ("2015 UAFVA")</u>

25. The purpose of the 2015 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 2015 Board approved UAF volumetric forecast. The 2015 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 2015 based on the estimated volumetric variance between the 2015 Board approved level of UAF and the estimate of the 2015 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.

2015 Storage and Transportation Deferral Account ("2015 S&TDA")

27. The purpose of the 2015 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.

28. The 2015 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.

29. The 2015 S&TDA will also record the variance between the forecasted commodity cost for fuel and the updated QRAM Reference Price.

30. Simple interest is to be calculated on the opening monthly balance of the 2015 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.

2015 Deferred Rebate Account ("2015 DRA")

31. The purpose of the 2015 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.

32. 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.

2015 Customer Care Services Procurement Deferral Account ("2015 CCSPDA")

33. The purpose of the 2015 CCSPDA is to capture the costs associated with the benchmarking, tendering and potential transition of customer care services to a new service provider(s). The Ontario Energy Board's EB-2012-0459 Decision approved the establishment and continuation of this account for 2014 through 2016, but limits the total amount recordable in the account to $5 million.

34. The majority of EGD's 2013 through 2018 customer care costs were established and approved for recovery in the Settlement Agreement approved in the EB-2011-0226 proceeding, including costs for services provided under two major outsourced customer care agreements which had expiry dates of December 31, 2017. Those

agreements were subject to extension rights available to the Company. The costs related to the process of procuring continuing customer care services beyond the end dates of those agreements, including costs for benchmarking (to confirm the validity of pricing and quality for such services) and tendering for services provided by those agreements, , were not included, nor were any potential transition costs to new providers.

35. In November 2014, the Company elected to exercise the 2018 and 2019 option years for the main customer care service agreement (the Accenture CCSA) in order to secure more favourable pricing starting in 2015 through to and including 2018 and 2019. As a result of the extension, the Company does not anticipate conducting customer care procurement activities in 2015, and as such does not anticipate recording any costs in the 2015 CCSPDA.

36. 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>2015 Customer Care CIS Rate Smoothing Deferral Account ("2015 CCCISRSDA")</u>

37. The purpose of the 2015 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 account 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 it is to be cleared along with the clearance of other deferral and variance accounts.

38. 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>2015 Average Use True-Up Variance Account ("2015 AUTUVA")</u>

39. The purpose of the 2015 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.

40. 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.

2015 Greenhouse Gas Emissions Impact Deferral Account ("2015 GGEIDA")

41. The purpose of the 2015 GGEIDA is to record any impacts to EGD resulting from federal and/or provincial 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.

42. 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.

2015 Earnings Sharing Mechanism Deferral Account ("2015 ESMDA")

43. The purpose of the 2015 ESMDA is to record the ratepayer share of utility earnings that result from the application of the earnings sharing mechanism ("ESM"). If the 2015 actual utility return on equity ("ROE"), calculated on a weather normalized basis, exceeds the Board's approved formula ROE utilized in determining 2015 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.

2015 Manufactured Gas Plant Deferral Account ("2015 MGPDA")

45. The purpose of the 2015 MGPDA is to capture all costs incurred in managing and resolving issues related to the Company's Manufactured Gas Plant ("MGP") legacy operations. Amounts recorded in the 2014 MGPDA will be transferred to the 2015 MGPDA. 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. 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>2015 Gas Distribution Access Rule Impact Deferral Account ("2015 GDARIDA")</u>

48. The purpose of the 2015 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.

49. 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 the account along with interest charges will be disposed of after review and as designated by the Board.

2015 Electric Program Earnings Sharing Deferral Account ("2015 EPESDA")

50. The purpose of the 2015 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.

51. 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 the account along with interest charges will be disposed of after review and as designated by the Board.

2015 Open Bill Revenue Variance Account ("2015 OBRVA")

52. 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.

53. 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>2015 Ex-Franchise Third Party Billing Services Deferral Account (“2015 EFTPBSDA”)</u>

54. The purpose of the 2015 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.

55. 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>2015 Constant Dollar Net Salvage Adjustment Deferral Account (“2015 CDNSADA”)</u>

56. The purpose of the 2015 CDNSADA is to record and clear the 2015 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 EGD’s depreciation rates.

57. 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 accumulated depreciation balances. Within EGD's EB-2012-0459 decision (2014-2018 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.

58. 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.

59. 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 2014 CDNSA will be transferred to the 2015 CDNSA.

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

<u>2015 Transition Impact of Accounting Changes DA ("2015 TIACDA")</u>

61. The TIACDA is required to track and record the remaining un-cleared balance associated with Other Post Employment Benefit "("OPEB") amounts in respect of which the Board approved recovery of within the EB-2011-0354 proceeding. In that

proceeding, the Board approved the even recovery of an original estimated amount of $90 million, at an amount of $4.5 million over 20 years commencing in 2013. The final estimate which EGD recorded in the TIACDA at the end of 2012 was $88.7 million, which EGD will clear evenly over 20 years commencing in 2013. The final estimate and the recovery of the first $4.4 million (1/20 of $88.7 million) installment was approved for recovery in EB-2013-0046. 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.

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

<u>2015 Post-Retirement True-Up VA ("2015 PTUVA")</u>

63. The purpose of the 2015 PTUVA is to record the differences between forecast 2015 pension and post-employment benefit expenses of $37.3 million (see Exhibit D1, Tab 5, Schedule 1), and actual 2015 pension and post-employment benefit expenses (both determined on an accrual basis). The 2015 PTUVA will be cleared in a manner that will allow for all variances between $37.3 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 2015 PTUVA will be $5 million, and any remaining amounts will be transferred to the 2016 PTUVA for future clearance.

64. 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>2015 Greater Toronto Area Incremental Transmission Capital Revenue Requirement Deferral Account ("GTAITCRRDA")</u>

65. 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.

66. The purpose of the GTAITCRRDA will be 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 transportation customer(s), or there is no ability for transportation customer(s) to utilize Segment A (i.e., TransCanada's King's North project is delayed).

67. 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 to be paid by transportation customers as a result of upsizing the pipeline for transportation purposes.

68. 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>2015 Demand Side Management Variance Account (“2015 DSMVA”)</u>

69. The purpose of the 2015 DSMVA is to record the difference between the actual 2015 DSM spending and the budgeted $35.0 million included within 2015 rates (as outlined within Exhibit D1, Tab 4, Schedule 1 of this proceeding). Amounts determined to be over or under the budget included within rates will be incorporated into the DSMVA. In addition, any further variance in 2015 DSM spending and results, beyond the budget included within rates, which occurs as a result of Board decisions in upcoming DSM proceedings, will be included within the DSMVA.

70. 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>2015 Lost Revenue Adjustment Mechanism (“2015 LRAM”)</u>

71. The purpose of the 2015 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, 2015 to December 31, 2015.

72. 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.

73. 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.

2015 Demand Side Management Incentive Deferral Account ("2015 DSMIDA")

74. The purpose of the 2015 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 current DSM Framework and Guidelines proceeding EB-2014-0134, and Enbridge's forthcoming 2015-2020 DSM Plan proceeding.

75. 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.

2015 Unabsorbed Demand Cost Deferral Account ("2015 UDCDA")

76. As described in its gas cost evidence at Exhibit D1, Tab 2, Schedule 1, the Company has contracted for incremental long haul FT capacity on TCPL to meet its Peak Day requirements in 2015. A consequence of contracting for incremental long haul capacity is the possibility of unabsorbed demand charges (UDC).

77. To the extent that the Company is unable to utilize 100% of its contracted long haul TCPL FT capacity to meet customer demand and/or fill storage then the associated UDC costs will be debited in the UDCDA. Enbridge's forecast of UDC costs for 2015 is $166.4 million. That is the maximum amount that may be recorded within /u the 2015 UDCDA.

78. Enbridge will use its best efforts to mitigate the UDC that would otherwise be recorded in the 2015 UDCDA. For example, Enbridge will use transportation capacity to fill storage (by displacing discretionary purchases of gas at Dawn) where that is reasonably possible, to reduce the total amount of unutilized capacity. Where there is unutilized capacity, Enbridge will make best efforts to assign that capacity to third parties, to mitigate the UDC costs. The outcome of Enbridge's best efforts to mitigate UDC will be reflected in the amounts recorded in the 2015 UDCDA.

79. 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. Depending on the magnitude of the balance, the Company may propose clearance through a onetime charge, or over 12 months which is consistent with the clearance of PGVA balances.

80. In order to keep the Board and interested parties informed as to the total unutilized transportation costs the Company intends to provide the actual balance in the UDCDA and the applicable interest through the QRAM process.

2015 Dawn Access Costs Deferral Account ("2015 DACDA")

81. 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.

82. The purpose of the 2015 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.

83. 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.

2015 Credit Final Bill Deferral Account ("2015 CFBDA")

84. The purpose of the 2015 CFBDA is to address a billing related issue which the Company has identified as resulting from the 2009 CIS implementation, specifically final bills with credit balances. The account will be used to track un-refunded customer final bill credit amounts, aged two years or more, while continuing efforts are made to return as much of the amounts as possible to the former account holders. Therefore, final bill credit balances aged two years or more will be credited to the account. As the affected customers will always be entitled and able to receive refunds any future refund amounts paid relating to amounts already credited to the CFBDA would be debited to the account. The year-end balance in this account will be brought forward for clearance to ratepayers.

85. Further evidence explaining the CFBDA can be found at Exhibit D2, Tab 1, Schedule 2.

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.

CREDIT FINAL BILL DEFERRAL ACCOUNT

1. The purpose of this evidence is to address a billing related issue that the Company has become aware of: Final Bills with Credit Balances and seek approval to create the Credit Final Bill Deferral Account ("CFBDA").

2. In October 2011, the Company identified an issue in relation to the finalization of accounts as a result of customer move-outs/move-ins. Customer accounts affected by this issue have a final negative account balance where the customer was not subsequently issued a refund cheque, or where credits were not transferred to an active account in the name of that customer. This problem arose as a result of the change over to the Company's current Customer Information System ("CIS") in September 2009.

3. Subsequent analysis determined that there were issues concerning both the design of the new CIS and the related business processes that contributed to this problem:

- System Defects or design issues: where billing scenarios were not contemplated in design and/or a system defect resulted in credits on finalized accounts not to be cleared (examples include application of interest on security deposits or account adjustments applied to an account after a final invoice was issued; as well the automatic transfer functionality did not work as designed).
- Changes to business processes: Functionality to transfer balances from a customer's final account a new account (such as when a customer moves) was assumed to be working, where in fact it was not. As a result, business processes to refund credits were limited in the new CIS to situations only when customers move out of the franchise area.

- automated transfer functionality to transfer credit balances to an active account in the name of the same customer,
- logic to provide for the creation and issuance of a second final bill enabling the Company to convey credit amounts to the customer that arise after the original final bill is produced,

Since the time these issues were discovered the Company has implemented numerous changes to its CIS to correct the system related problems, these changes, amongst others, include;

- automated refund of credit balances at time second final bill is produced,
- logic to calculate Security Deposit interest and credit it to the final bill,
- ability to automatically generate a written notice to the customer that they have made a payment in error on a final bill with a balance of zero or less,
- automated removal of finaled accounts from the Preauthorized Payment Plan, and
- creation of a credit clarification work-list identifying finaled accounts aged 60 days or more having credit balances to facilitate manual follow-up.

4. The Company has also issued revised system user documentation and work instructions to ensure that the system is properly used and taken steps to ensure the proper business process steps are followed.

5. At issue is the fact that during the time from September 2009 until the required remedies were implemented there were a significant number finalized accounts having credit balances where amounts were not transferred or refunded to customers. Over the past three years the Company has undertaken a substantial

and continuing effort to reconcile these accounts and, where appropriate, identify those parties that are owed money and refund it to them. The Company has employed automated techniques to identify forwarding addresses and manual efforts have been undertaken by a dedicated work team to locate these customers. These efforts have included outbound telephone calling, issuance of letters to the customer's last known address, and issuance of refund cheques that have been sent to the customer's last known address.

6. Despite these efforts some customers have not been located. Since this work began in 2012 the Company has manually returned or resolved $16 million in credits. As of September 30th, 2014 there remain approximately 54,000 finalized accounts with credit balances totaling $9 million aged two years or more where the Company has not been able to locate the former account holder and refund the respective credit balance to them. In most cases these accounts have been finalized for over two years and considerable efforts have been applied to locate these past customers. At this point, it is unlikely that the Company will be able to return the amounts owed to these customers.

7. Given the dollar amount of these outstanding credits and the unique nature of their creation the Company proposes that a deferral account, the CFBDA be established to track these un-refunded credit amounts while continuing efforts to return as much of this money as possible to the former account holders. The deferral account would capture final bill credit balances aged two years or more. As the affected customers will always be entitled and able to receive refunds any future refund amounts paid relating to amounts already credited to the CFBDA would be debited to the account.

8. The Company proposes that the balance of the CFBDA be brought forward at each year-end for clearing to ratepayers in conjunction with the disposition of other deferral and variance accounts. It is expected that the amounts flowing through this account will be significant in 2015, but due to the steps the Company has taken to remedy this situation amounts will be reduced thereafter as the impacted historic accounts reach two years of age.

9. Although Enbridge has implemented system business process changes and training to reduce the occurrence of final account credit amounts, there has not yet been sufficient experience to determine the continued rate of reduction in the balance of credits attributable to this system issue. Therefore, Enbridge believes that it is appropriate to have the CFBDA continue until such time as it is clear that it is no longer needed. The Company proposes that the CFBDA continue to operate from year to year and be annually cleared to ratepayers until such time as the balance of this account is determined to no longer be of a material value