CCC INTERROGATORY #5

INTERROGATORY

Ex. D1/T2/S1

EGD's evidence is that it is making changes to the way in which it forecasts gas costs and manages its gas supply planning. Please set out in a table the specific changes proposed for 2015 relative to 2014, the rationale for the changes, and the potential impacts on customers. In addition, please set out the specific relief requested regarding gas costs and its gas supply planning process through this application.

RESPONSE

There are two modifications that the Company is implementing as a part of its 2015 gas supply planning process.

As discussed in Exhibit D1, Tab 2, Schedule 1, page 9 and10, the Company is altering its planned storage targets. In 2015, the Company is planning to maintain storage targets such that maximum deliverability from storage can be maintained until the end of February and that there is sufficient storage deliverability to meet a March peak day as late as March 31. This is discussed further in response to Board Staff Interrogatories #10 and 12 at Exhibit I.D1.EGDI.STAFF.10 and Exhibit I.D1.EGDI.STAFF.12.

The other aspect of the planning process that the Company intends to implement in the winter of 2014/15 is to make changes to its procurement practices. The Company intends to look to medium-term weather forecasts as a means of assessing medium-term demand. The Company will utilize this information to help decide whether or not it should adjust its planned procurement for the upcoming month. The new approach being employed by the Company is described in response to Board Staff Interrogatories #11 and 12 at Exhibit I.D1.EGDI.STAFF.11 and Exhibit I.D1.EGDI.STAFF.12.

The relief the Company is seeking within this proceeding is the acceptance of its gas supply plan and associated costs as filed at Exhibit D1, Tab 2, Schedule 4, page 2, which will be updated in accordance with the QRAM methodology throughout 2015.

Witness: D. Small

CCC INTERROGATORY #6

INTERROGATORY

Ex. D1/T2/S1/p.9

EGD is implementing changes for 2015 with respect to the way in which it manages its storage balances. What is the expected incremental cost of these proposals? Please explain all of the alternatives EGD considered with respect to storage utilization. Please explain why the current proposal was chosen over the alternatives.

RESPONSE

Please see response to Board Staff Interrogatory #10 at Exhibit I.D1.EGDI.STAFF.10.

Witness: D. Small

CCC INTERROGATORY #7

INTERROGATORY

Ex. D1/T2/S1/p. 4

Please explain why there is an increase of $3.9 million related to Customer Care and CIS for 2015 relative to 2014. Is Accenture providing a level of increased services in 2015 that accounts for the increase?

RESPONSE

The $3.9 million increase in 2015 Customer Care and CIS costs is not correlated to the level of service provided by Accenture. The $3.9 million increase in Customer Care and CIS costs included within 2015 allowed revenues, as compared to the Customer Care and CIS costs included within 2014 allowed revenues, was determined through the application of the Board approved EB-2011-0226 Settlement Agreement, which established how Customer Care and CIS costs would be established and recovered in each of 2013 through 2018. As specified within the EB-2011-0226 Settlement Agreement, the Customer Care and CIS costs to be collected in revenue requirement (allowed revenues), in each of 2013 through 2018, is to be determined annually by multiplying the forecast number of customers for that year by the smoothed revenue requirement unit rate per customer for that year. The forecast number of customers is to be updated annually as part of the annual rate setting process. Following this methodology, 2015 Customer Care and CIS costs included within allowed revenues, of $118.0 million, was determined by multiplying the updated 2015 forecast number of customers included within this proceeding, of 2,112,148, by the 2015 smoothed revenue requirement unit rate per customer of $55.88. This is a $3.9 million increase over the $114.1 million approved and included within 2014 allowed revenues, established within EB-2012-0459, that was determined by multiplying the updated 2014 forecast number of customers (established within EB-2012-0459), of 2,086,534, by the 2014 smoothed revenue requirement unit rate per customer of $54.68.

The 2015 smoothed revenue requirement unit rate per customer, the updated 2015 customer forecast, and the 2015 Customer Care and CIS costs included within allowed revenues are shown in the Updated CIS/CC Template for 2015, Exhibit D1, Tab 3, Schedule 3, in Column J, Rows 24, 25, and 27. The corresponding 2014 values which were approved within EB-2012-0459 are shown in Column I of the same exhibit.

The process of updating 2015 Customer Care and CIS costs is described in greater detail in Exhibit D1, Tab 3, Schedule 1.

Witnesses: K. Culbert
K. Lakatos-Hayward
R. Small

CME INTERROGATORY #8

INTERROGATORY

Reference: Exhibit D1, Tab 1, Schedule 1, Table 1

Please add a column to Table 1 to show 2014 actuals for each line item.

RESPONSE

2014 actual results and data are not relevant to the determination of the Company's 2015 rate application. As such, the Company declines to provide the requested information.

The Company's 2015 Final Rates are to be determined in accordance with the "Customized IR" model approved by the Board in its EB-2012-0459 Decision. As indicated within Exhibit A1, Tab 3, Schedule 1, the Board, in its EB-2012-0459 Decision, approved those elements which are to be updated annually within a subsequent rate application for each of the fiscal years from 2015 to 2018. Other items were fixed in the EB-2012-0459 Decision.

At the time of preparing and filing a rate adjustment application for each of the 2015 through 2018 years, the Company will use the most current actual data available at the time of application. Assuming an application is filed around October 1st for rates for the next year, this means that actual data for the full current year will not be available. The use of any full year actual data within the forecasting of the approved elements required to be updated annually will occur within the second year following such actuals. For example 2014 and 2015 actual data will be taken into account when forecasting degree days, volumes, etc., within the 2016 and 2017 fiscal years respectively. In the case of the Company's 2015 rate adjustment application, full year actual data from 2013 was taken into account.

Actual data and results from 2014 will be filed with the Board and subject to review in the context of the Company's 2014 Earnings Sharing Application. It will also be communicated to all stakeholders and discussed as part of the annual stakeholder day that Enbridge will hold later this spring, in accordance with commitments made in the EB-2012-0459 Decision. Further, actual data and results from 2014 will be relevant and applied by the Company in the preparation of its 2016 Rate Adjustment Application.

Witness: R. Small

CME INTERROGATORY #9

INTERROGATORY

Reference: Exhibit D1, Tab 2, Schedule 1, page 2, question 3

Of the total forecast supply for 2015 of 270.4 Bcf, please provide the following additional information:

(a) The approximate volume of supply which will be sourced from the Appalachian Basin; and

(b) A description of the extent to which the 2015 Gas Supply Plan will produce gas savings for Ontario consumers as a consequence of a greater proportion of supply being acquired from the Appalachian Basin. Please quantify the approximate value of those savings.

RESPONSE

a) Included in the Company's 2015 supply plan is the acquisition of 11.4 Bcf during the months of November and December 2015 to be delivered at Niagara. While the Company is negotiating with various suppliers for the delivery of gas at the Niagara inter-connect, it can be assumed that these supplies will originate from the Appalachian Basin.

b) Because the 2015 supply plan only assumes approximately 4% of the supply portfolio to be acquired at Niagara the savings in 2015 are relatively small. Based upon the commodity prices and transportation tolls in place at the time the Company prepared its 2015 forecast, the differential between buying gas in western Canada and using TCPL long haul capacity versus buying gas at Niagara and using TCPL's short haul capacity indicates potential savings in 2015 of approximately $10 million. The potential for savings becomes greater in 2016 and beyond as the Company reduces its reliance on western Canadian supplies and TCPL long haul capacity and replaces it with some Niagara supply and by acquiring even greater volumes at Dawn. The expectation is that the availability of gas from the Marcellus and Utica shale basins will continue to have a positive effect on prices at Dawn not only impacting the cost of the supplies the Company acquires but also benefiting Direct Purchase customers who will be able move to the Dawn T-Service option.

Witness: D. Small

CME INTERROGATORY #10

INTERROGATORY

Reference: Exhibit D1, Tab 2, Schedule 1, pages 6 & 7, questions 15 and 16

At Exhibit D2, Tab 1, Schedule 1, page 23, EGD forecasts that, subject to its mitigation efforts, its customers will be called upon to pay about $130 M for unutilized TransCanada PipeLines Limited ("TCPL") pipeline capacity. In connection with this evidence and all of the upstream pipeline capacity EGD holds, please provide the following information:

(a) Are EGD's customers expected to pay for any other upstream pipeline capacity held by EGD which the company does not expect to fully utilize in 2015? If so, then please estimate the total UDC costs which EGD's customers face on all of the upstream pipeline capacity to be held by EGD in 2015; and

(b) To what extent are the costs for unutilized upstream capacity on TCPL attributable to the Tolls and Tariffs Settlement Agreement which EGD and other distributors entered into with TCPL?

RESPONSE

(a) The Company is currently forecasting to utilize 100% of its contracted capacity on its other long haul transportation contracts.

(b) The forecasted cost of the unutilized long haul TCPL transportation capacity has been updated (Exhibit D1, Tab 2, Schedule 1) to $166.4 million to reflect the Interim Mainline Transportation Tolls and Interim Abandonment surcharges effective January 1, 2015 which includes the impact of the Mainline Settlement Agreement between TCPL and EGD and other distributors. Based upon the TCPL Interim Mainline Transportation Tolls and Interim Abandonment Surcharges the Company has updated Exhibit D1, Tab 2, Schedule 1, Appendix A resulting in forecasted UDC of $166.4 million. The Company has also updated its pre-filed evidence at Exhibit D1, Tab 2, Schedule 1, page 6, paragraph 15 and at Exhibit D2, Tab 1, Schedule 1, page 23, paragraph 77 to reflect the change as well.

While the costs associated with the unutilized capacity are underpinned by the updated tolls the volumetric level of unutilized capacity is not. As discussed in the EB-2012-0459 Settlement Agreement dated October 29, 2013, the increase in

Witness: D. Small

unutilized transportation capacity was predominantly a result of changes to discretionary services offered by TCPL that were approved by the National Energy Board as part of the RH-03-2011 proceeding. The Short Term Firm Transportation ("STFT") capacity, which the Company had relied upon in prior years when developing its gas supply portfolio became more costly and had to be replaced with annual Firm Transportation (FT).

The Mainline Settlement Agreement also provided for market access to supply basins such as Dawn, and as a result will contribute to a reduction in costs associated with unutilized TCPL long haul transportation capacity.

CME INTERROGATORY #11

INTERROGATORY

Reference: Exhibit D, Tab 2, Schedule 1, page 7, question 17

EGD includes in its 2015 Revenue Requirement costs associated with its Segment A of the GTA Project on the basis of a forecast that these transmission facilities will be in service on November 1, 2015. We understand that this transportation capacity cannot be utilized until incremental inter-connecting facilities have been constructed by TCPL. In the recently concluded Natural Gas Market Review proceeding, TCPL indicated that it would be impossible for it to meet a November 1, 2015 in-service date for its facilities. In these circumstances, please provide the following information:

(a) If the Board finds that Segment A will be unable to provide any transportation service before 2016, is it correct to conclude that the 2015 Revenue Requirement and Rates will be reduced by the $3.54 M shown at Exhibit G1, Tab 1, Schedule 1, page 4? If this is not the correct amount, then please provide a calculation of the extent to which the 2015 Revenue Requirement would be reduced if transportation service on the GTA Project cannot actually be provided by EGD in 2015.

RESPONSE

Where transportation capacity is unable to be utilized at November 1, 2015 due to a lack of connection facilities construction by TCPL, Enbridge still anticipates that Segment A will be completed by November 1, 2015 and used by Enbridge's customers.

As shown within Exhibit G1, Tab 1, Schedule 1, page 4, out of the total $3.54 million Segment A revenue requirement for 2015, 60% or $2.13 million is forecast to be recovered from Rate 332 transportation service customers. Where Rate 332 transportation service is unable to commence in 2015 there is no need to reduce the total revenue requirement by the $2.1 million. However, to the extent that Enbridge does not recover that amount from Rate 332 transportation customers, then Enbridge will record the $2.1 million revenue requirement in the GTA deferral account approved in the GTA LTC proceeding for future recovery from appropriate customers.

Witnesses: K. Culbert
A. Kacicnik
R. Small

FRPO INTERROGATORY #1

INTERROGATORY

Gas Costs, Transportation and Storage

Reference: *Exhibit D1, Tab 1, Schedule 2, Page 2 of 2*

Please provide a breakout of the main drivers behind the $80.3M increase between:

a. Updated 2015 volume forecast.
b. Gas Supply Plan
c. October 1, 2014 QRAM prices.

RESPONSE

As the table attached illustrates, there are two primary reasons for the difference in the gas cost forecast between the 2015 Utility Placeholder and the 2015 Updated Forecast.

First, the 2015 Placeholder was based upon the April 2013 QRAM Reference Price and the TCPL tolls in place at that time while the 2015 Updated Forecast is based upon the October 2014 QRAM Reference Price and the TCPL tolls in place at that time.

Second, when the 2015 Placeholder was prepared the Company forecast that it would be able to utilize STFT as part of its supply plan and the associated UDC costs would be captured as a part of gas cost. The decision by the Company to acquire FT instead of STFT changed the amount of forecasted UDC and the Company sought approval of a deferral account to record UDC.

There was also a difference in the forecasted Sales and Western T-Service between the two forecasts and a difference in Storage and Transportation Charges.

Witness: D. Small

Item #		Adjusted April 13 QRAM 2015 Placeholder			Adjusted October 14 QRAM 2015 Updated Forecast			Difference
		10*3 m*3	$/10*3 m*3	$ million's	10*3 m*3	$/10*3 m*3	$ million's	$ million's
1.	Sendout Volume	7,776,932.9	181.470	1,411.3	7,445,672.6	204.293	1,521.1	109.8
2.	Western T-Service	779,520.0	84.535	65.9	1,033,375.6	59.017	61.0	(4.9)
3.	- excludes Ontario T-Service volumes	8,556,452.9		1,477.2	8,479,048.2		1,582.1	104.9
4.	Storage And Transportation Charges			103.1			105.0	1.9
5	Unutilized Transportation Costs			26.5			-	(26.5)
6.	- as Ex D1, T1, Sch. 2, page 1 of 2 - Line # 1			1,606.8			1,687.1	80.3

FRPO INTERROGATORY #2

INTERROGATORY

Gas Costs, Transportation and Storage

Reference: *Exhibit D1, Tab 2, Schedule 1, Page 4 of 11*

Please confirm the allocation of Peaking Services to Load Balancing

a. If not confirmed, please provide the allocation methodology and basis for the allocation.
b. Please provide the methodology to separate the commodity cost from other allocations.

RESPONSE

a) Confirmed. Also, please see part b) below.

b) As per the Board approved methodology, Enbridge employs an "Empress reference price" which is based on a 21-day forecast of market commodity prices (i.e. "21-day strip") at Empress for the next 12-month period, and is adjusted each quarter through the Quarterly Rate Adjustment Mechanism (QRAM) process. These commodity costs are recovered from system gas customers through the Company's gas supply commodity charge.

Enbridge sources gas supplies from a number of market hubs and transports supplies via a number of transportation paths to achieve diversity, reliability, and flexibility of its gas supply plan. Being close to the gas supply basin means the price of gas supply at Empress reflects the cost of the commodity itself, while the prices of gas supplies at Chicago or Dawn hubs incorporate the cost of transporting the gas to Chicago or Dawn. In other words, the price premium at Chicago or Dawn over Empress notionally reflects the cost of getting the gas to Chicago or Dawn.

Any price premium for gas supplies purchased at other supply hubs over the Empress reference price is classified as transportation and, in the case of delivered supplies and peaking service, to load balancing. Transportation costs are recovered from System Gas and Western T-service customers, and load balancing costs are recovered from all customers (System Gas, Western T-service, and Ontario T-service).

Witnesses: A. Kacicnik
M. Kirk

FRPO INTERROGATORY #3

INTERROGATORY

Gas Costs, Transportation and Storage

Reference: *Exhibit D1, Tab 2, Schedule 1, Page 4 of 11*

How does Enbridge determine the value of Peaking Services relative to other alternatives?

a. Please describe the process using the 2014/15 winter for context.

RESPONSE

The Company believes that in today's marketplace the only alternative to Peaking Service is to contract for Firm Transport on TCPL. In response to Board Staff Interrogatory #6 at Exhibit I.D1.EGDI.STAFF.16, the Company discusses further why it has chosen to maintain Peaking Service at levels consistent with prior years.

The process followed by the Company for acquiring Peaking Service for the 2014/15 winter is consistent with prior years. The Company will issue an RFP for service and will receive responses from potential suppliers that include indicative pricing. The indicative pricing allows the Company to value or rank the responses received in order to determine who the Company will contract with for Peaking Service.

Witness: D. Small

FRPO INTERROGATORY #4

INTERROGATORY

Gas Costs, Transportation and Storage

Reference: *Exhibit D1, Tab 2, Schedule 1, Page 5 of 11*

Please breakdown the respective contributions to peak day increase demand (in GJ/day) between:

a. an increase in the overall peak day demand due to growth
b. a decline in the level of interruptible volume largely stemming from a decline in the number of interruptible customers
c. the migration of Ontario T-Service ("OTS") customers to either System Sales or Western T-Service ("WTS")
d. a decrease in available delivered service supplies
    i. Please elaborate on the decrease in available deliverable supplies

RESPONSE

The Company provided a schedule (Exhibit D1, Tab 2, Schedule 6) comparing the 2014 Budget Peak Day Demand and the 2015 Budget Peak Day Demand and the forecasted supplies to satisfy the budgeted Peak Day Demand.

Item 1 of that schedule illustrates that the Budget Peak Day Demand increased by 16,240 GJ's in 2015 versus 2014. However, as Item 2 indicates the forecasted level of curtailment declined by 45,567 GJ's in 2015 resulting in an overall increase in the Net Peak Day Demand of 61,807 GJ's in 2015 (see Item 3).

Item 8 represents the Ontario T-Service daily delivery volume and shows the decline from 326,930 GJ's per day in 2014 to 249,071 GJ's per day. The 77,859 GJ/day decline can be attributable to either customers returning to system sales or because of Direct Purchase customers switching to the Western T-Service option.

In 2014 the Company was able to acquire 150,000 GJ's per day of delivered supply directly into the CDA. In 2015 the Company was only able to contract for 135,000 GJ's per day. This accounts for the decline in Item 10 on the schedule.

Witness: D. Small

The increase in the overall peak day requirement of 61,807 GJ's per day combined with the decline in available supply of 92,859 GJ's per day meant the Company needed to acquire a total of 154,666 GJ's per day of transportation to the franchise area. The most cost effective reliable alternative was to acquire incremental long haul capacity from TCPL which is shown in the increase in Item 4.

.

Witness: D. Small

FRPO INTERROGATORY #5

INTERROGATORY

Gas Costs, Transportation and Storage

Reference: *Exhibit D1, Tab 2, Schedule 1, Page 5 and 6 & Exhibit D1, Tab 2, Schedule 6*

Preamble: In past proceedings starting with EB-2010-0231 Enbridge increased its firm capacity. In EB-2014-0259, Enbridge established a Settlement Agreement with intervenor groups for the increase in FT capacity and the associated UDC risk.

Please confirm that no such Agreement was reached for the incremental FT capacity contracted for and that type of Agreement was not sought by the company.

RESPONSE

The situation that prevailed prior to the beginning of 2014 was an extenuating circumstance resulting in a significant change to the 2014 gas supply plan as filed. For 2015, the Company did not seek an agreement from Intervenors similar to EB-2014-0259 for two reasons. First, the circumstances surrounding whether or not STFT was an option to satisfy demand had not changed from last year. Second, a consequence of Direct Purchase customers switching to Western T-Service would result in customers delivering their MDV at Empress 365 days a year. As a result the Company required the necessary transport to move that gas to Ontario. For additional information on the switch from Ontario T-Service to Western T-Service please see the response to FRPO Interrogatory #4 at Exhibit I.D1.EGDI.FRPO.4.

Witness: D. Small

FRPO INTERROGATORY #6

INTERROGATORY

Gas Costs, Transportation and Storage

Reference: *Exhibit D1, Tab 2, Schedule 1, Page 5 and 6 & Exhibit D1, Tab 2, Schedule 6*

Preamble: In past proceedings starting with EB-2010-0231 Enbridge increased its firm capacity. In EB-2014-0259, Enbridge established a Settlement Agreement with intervenor groups for the increase in FT capacity and the associated UDC risk.

Please provide the term of the incremental FT contracts categorized by end date of the contract.

RESPONSE

The Company included within its 2015 application a schedule listing the status of the various gas supply transportation contracts that will be relied upon as a part of the overall gas supply plan in 2015 (Exhibit D1, Tab 2, Schedule 2, page 1).

There are three long haul TCPL transportation contracts that the Company entered into to help meet the change in peak day demand that is described in the response to FRPO Interrogatory #4 at I.D1.EGDI.FRPO.4.

Item 4 of Exhibit D1, Tab 2, Schedule 2 is for transportation capacity between Empress and the CDA for 56,000 GJs per day that expires October 31, 2015. Included within Item 7 is 20,000 GJs per day of Empress to EDA capacity which also expires October 31, 2015.

The third contract entered into by the Company is shown at Item 43 for 75,000 GJs per day of Empress to CDA capacity that expires October 31, 2018. Unlike the other two contracts Enbridge submitted a bid for a period longer than one year to ensure that the bid would be successful. The bid was in response to TCPL's NCOS which ran from October 22nd to October 27th and identified the available capacity in the CDA to be 164,118 GJ's per day effective January 1, 2015. The Company was concerned with a perceived shortage of capacity and it understood that there were other significant bidders looking to fulfill their requirements. The Company therefore chose to bid for a longer term to ensure it was awarded all of the capacity required to meet its peak day in

Witness: D. Small

2015. When bidding in for the longer term the Company also took into consideration two contracts set to expire March 31, 2015 (Items 45 and 47). The Company also recognized the potential of not renewing the contact identified as Item 1 that is scheduled to expire October 31, 2017.

FRPO INTERROGATORY #7

INTERROGATORY

Gas Costs, Transportation and Storage

Reference: *Exhibit D1, Tab 2, Schedule 1, Page 5 and 6 & Exhibit D1, Tab 2, Schedule 6*

Preamble: In past proceedings starting with EB-2010-0231 Enbridge increased its firm capacity. In EB-2014-0259, Enbridge established a Settlement Agreement with intervenor groups for the increase in FT capacity and the associated UDC risk.

Please provide and quantify the compensatory steps that Enbridge assessed and planned (plans) to take to mitigate the additional UDC risk including:

a. Reduction in deliveries at Dawn
b. Changes in storage (capacity and deliverability) for 2014/15
c. Planned changes in storage (capacity and deliverability) for 2015/16

RESPONSE

a) As discussed in response to Board Staff #8 at Exhibit I.D1.EGDI.STAFF.8 and CME #12 at Exhibit I.D2.EGDI.CME.12, the Company will follow a similar practice as it followed in 2014. Included within the 2015 gas supply plan is the acquisition of 15.3 PJ's of discretionary supplies in the summer of 2015. If the Company requires that supply then it will fill the unutilized capacity first before purchasing gas at Dawn. If there remains unutilized capacity and market conditions are conducive, the Company will release that capacity into the market which will generate revenue to offset the cost of the unutilized capacity.

b) The changes with respect to how the Company intends to manage its storage capacity do not include contracting for additional capacity but instead changing its purchase patterns to maintain higher amounts of gas in storage until later in the winter season.

c) The Company has not completed its gas supply plan for 2015/16 at this time. The Company has not planned or is not currently planning, at this time, to alter its storage capacity requirements or deliverability requirements. As discussed in response to Board Staff #10 at Exhibit I.D1.EGDI.STAFF.10, the Company intends to investigate further the level of incremental storage that would be required and report back to interested parties in a future proceeding. However, if the Company was to acquire additional storage capacity for the 2015/16 winter season, it expects that it could fill that storage capacity by utilizing some of the transportation capacity currently forecasted to remain empty in the summer of 2015.

FRPO INTERROGATORY #8

INTERROGATORY

Gas Costs, Transportation and Storage

Reference: *Exhibit D1, Tab 2, Schedule 1, Page 5 and 6 & Exhibit D1, Tab 2, Schedule 6*

Preamble: In EB-2012-0459, Enbridge provided a response to FRPO letter regarding additional detail on transportation, degree days and UDC risk on February 27, 2014.

Please reproduce the table provided on page 4 with actual results to October 31, 2014 adding:

a. Actual degree days
b. Actual percentage storage capacity fill.

RESPONSE

The actual monthly degree days and actual percentage monthly storage capacity fill for the period January 2014 to December 2014 can be found on the Monthly UDC Report that the Company has filed with the Board – a copy has been attached.

The Company has reproduced the table provided on page 4 of the February 27, 2014 letter to include actual data for the January 2014 to December 2014 period. The Company is providing this response subject to the comments in EGD's letter of February 26, 2015 which sets out EGD's position as to the relevance of the 2014 actuals information being provided.

Witness: D. Small

ENBRIDGE

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December 31, 2014

VIA RESS and COURIER

Ms Kirsten Walli
Board Secretary
Ontario Energy Board
2300 Yonge Street, Suite 2700
Toronto, Ontario, M4P 1E4

Dear Ms Walli:

Re: Enbridge Gas Distribution Inc. 2014 to 2018 Rate Application
Ontario Energy Board File No. EB-2012-0459

As per the Settlement Agreement in EB-2012-0459 (Exhibit N1, Tab 2, Schedule 1, p. 6 of 19) the Company committed to provide a report to the parties of the Settlement Agreement to allow for the ongoing monitoring of UDC impacts in 2014. Please see the attached report for November, 2014.

Please do not hesitate to contact me with any questions.

Yours Truly,

(Original Signed)

Andrew Mandyam
Director, Regulatory Affairs and Financial Performance

Attach.

cc: EB-2012-0459 Interested Parties

December 2014 Report

Demand	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual - Updated July	Actual August	Actual September	Actual October	Actual November	Estimate December	
PJ's	85.9	73.1	70.5	40.9	22.1	15.4	15.4	14.7	16.5	27.0	51.7	60.6	493.9

Forecasted Monetary Impacts by Delivery Area
$ millions

	January	February	March	April	May	June	July	August	September	October	November	December	
UDCDA													
- CDA	-	-	-	-	-	-	0.6	4.5	2.9	3.2	-	-	11.2
- EDA	-	-	-	-	-	-	0.3	2.0	1.3	1.4	-	-	5.0
Revenue From Unutilized Capacity Released	-	-	-	-	-	-	(0.2)	(0.9)	(0.6)	(1.0)	-	-	(2.7)
Net Impact on Deferral Account	-	-	-	-	-	-	0.7	5.5	3.6	3.7	-	-	13.6
DDCTDA													
- CDA	-	-	-	-	-	-	3.5	3.6	3.5	3.0	-	-	13.6
- EDA	-	-	-	-	-	-	0.5	0.5	0.5	0.4	-	-	1.9
Revenue From Unutilized Capacity Released	-	-	-	-	-	-	(0.8)	(0.6)	(0.6)	(0.7)	-	-	(2.6)
Net Impact on Deferral Account	-	-	-	-	-	-	3.2	3.5	3.4	2.7	-	-	12.9

Forecasted Monthly Unutilized Capacity by Delivery Area
PJ's -

	January	February	March	April	May	June	July	August	September	October	November	December	
UDCDA													
- CDA	-	-	-	-	-	-	0.4	2.8	1.9	2.1	-	-	7.2
- EDA	-	-	-	-	-	-	0.2	1.2	0.8	0.9	-	-	3.1
Unutilized Capacity Released	-	-	-	-	-	-	(0.6)	(4.1)	(2.7)	(3.0)	-	-	(10.2)
Net Unutilized Capacity	-	-	-	-	-	-	-	-	-	-	-	-	-
DDCTDA													
- CDA	-	-	-	-	-	-	2.2	2.3	2.3	1.9	-	-	8.7
- EDA	-	-	-	-	-	-	0.3	0.3	0.3	0.3	-	-	1.2
Unutilized Capacity Released	-	-	-	-	-	-	(2.5)	(2.6)	(2.6)	(2.2)	-	-	(9.9)
Net Unutilized Capacity	-	-	-	-	-	-	-	-	-	-	-	-	-
Total													
- CDA	-	-	-	-	-	-	2.6	5.2	4.1	4.0	-	-	15.9
- EDA	-	-	-	-	-	-	0.5	1.5	1.1	1.1	-	-	4.2
Unutilized Capacity Released	-						(3.1)	(6.7)	(5.2)	(5.1)	-		
Net Unutilized Capacity	-	-	-	-	-	-	-	-	-	-	-	-	20.1
Degree Days													
Central Region	813.0	724.1	669.3	352.3	127.4	12.6	4.9	9.3	70.0	230.7	474.2	550.0	4,037.8
Niagara Region	758.1	679.1	637.5	330.0	137.6	14.9	5.1	5.8	69.9	203.1	439.6	526.1	3,806.8
Eastern Region	895.2	775.3	751.1	381.2	124.0	14.9	10.4	22.0	115.3	260.9	507.7	725.7	4,583.7

Discretionary Requirement

	January	February	March	April	May	June	July	August	September	October	November	December	
PJ's	15.0	16.2	21.8	9.0	-	-	-	-	-	-	5.1	13.5	80.6
Month end Storage Capacity													
% Fill	0.39	0.19	0.14	0.20	0.35	0.49	0.75	0.87	0.97	1.00	0.94	0.78	
Month end Storage Capacity Taget													
% Fill	0.47	0.24	0.06	0.07	0.20	0.36	0.56	0.75	0.92	1.00	0.95	0.78	

2013 Actual Column 1	Column 2	Item #	2014	Column 3	Column 4	Column 5	Column 6	Column 7	Column 8	Column 9	Column 10	Column 11	Column 12	Column 13	Column 14	Column 15
			PJ's													
November	December			January	February	March	April	May	June	July	August	September	October	November	December	
43.7	62.0	1.	Forecasted Demand	69.7	60.7	53.5	33.2	20.8	14.7	13.4	13.3	15.0	27.2	41.5	60.4	423.3
51.1	70.3		Actual Demand	85.9	73.1	70.5	40.9	22.1	15.4	15.4	14.7	16.5	27.0	51.7	60.6	493.9
			Supply													
19.3	19.9	2.	EGD Contracted Long Haul TCPL Capacity	19.5	17.6	19.2	18.9	19.8	18.9	19.5	19.6	18.9	19.5	19.1	19.7	230.1
-	-	3.	Less Unutilized Capacity	-	-	-	-	-	-	(3.1)	(6.7)	(5.2)	(5.1)	-	-	(20.1)
19.3	19.9			19.5	17.6	19.2	18.9	19.8	18.9	16.4	12.9	13.7	14.4	19.1	19.7	210.0
9.1	9.3	4.	Direct Purchase Own Transportation	9.9	8.7	9.5	9.4	10.9	10.5	10.6	10.5	9.9	9.6	8.3	8.6	116.3
8.7	8.9	5.	Alliance/Vector	8.8	8.1	10.2	8.6	9.0	8.6	6.9	6.2	6.0	6.3	7.7	9.0	95.4
2.1	11.4	6.	Dawn Discretionary	15.0	16.2	21.8	10.0	-	-	-	-	-	0.0	5.1	13.6	81.6
-	-	7.	Peaking Supplies	1.6	0.1	0.6	-	-	-	-	-	-	-	-	-	2.3
39.2	49.5		Total Supply	54.7	50.6	61.3	46.9	39.6	38.0	33.9	29.5	29.6	30.3	40.2	50.9	505.7
12.0	20.8	8.	Storage Requirement	31.2	22.5	9.2	(6.0)	(17.5)	(22.6)	(18.5)	(14.9)	(13.1)	(3.3)	11.4	9.7	(11.8)
51.2	70.3		Total Supply	85.9	73.1	70.5	40.9	22.1	15.4	15.4	14.7	16.5	27.0	51.7	60.6	493.9
		9.	Monetary Impacts by Delivery Area $ millions													
				January	February	March	April	May	June	July	August	September	October	November	December	
No UDC Incurred			UDCDA													
			- CDA	-	-	-	-	-	-	0.6	4.5	2.9	3.2	-	-	11.2
			- EDA	-	-	-	-	-	-	0.3	2.0	1.3	1.4	-	-	5.0
			Revenue From Unutilized Capacity Released	-	-	-	-	-	-	(0.2)	(0.9)	(0.6)	(1.0)	-	-	(2.7)
			Net Impact on Deferral Account	-	-	-	-	-	-	0.7	5.5	3.6	3.7	-	-	13.6
			DDCTDA													
			- CDA	-	-	-	-	-	-	3.5	3.6	3.5	3.0	-	-	13.6
			- EDA	-	-	-	-	-	-	0.5	0.5	0.5	0.4	-	-	1.9
			Revenue From Unutilized Capacity Released	-	-	-	-	-	-	(0.8)	(0.6)	(0.6)	(0.7)	-	-	(2.7)
			Net Impact on Deferral Account	-	-	-	-	-	-	3.2	3.5	3.4	2.7	-	-	12.9
		10.	Monthly Unutilized Capacity by Delivery Area PJ's -													
				January	February	March	April	May	June	July	August	September	October	November	December	
			UDCDA													
			- CDA	-	-	-	-	-	-	0.4	2.8	1.9	2.1	-	-	7.2
			- EDA	-	-	-	-	-	-	0.2	1.2	0.8	0.9	-	-	3.1
			Unutilized Capacity Released	-	-	-	-	-	-	(0.6)	(4.1)	(2.7)	(3.0)	-	-	(10.2)
			Net Unutilized Capacity	-	-	-	-	-	-	-	-	-	-	-	-	-

			DDCTDA													
			- CDA	-	-	-	-	-	-	2.2	2.3	2.3	1.9	-	-	8.7
			- EDA	-	-	-	-	-	-	0.3	0.3	0.3	0.3	-	-	1.2
			Unutilized Capacity Released	-	-	-	-	-	-	(2.5)	(2.6)	(2.6)	(2.2)	-	-	(9.9)
			Net Unutilized Capacity	-	-	-	-	-	-	-	-	-	-	-	-	-
			Total													
			- CDA	-	-	-	-	-	-	2.6	5.2	4.1	4.0	-	-	15.9
			- EDA	-	-	-	-	-	-	0.5	1.5	1.1	1.1	-	-	4.2
			Unutilized Capacity Released	-	-	-	-	-	-	(3.1)	(6.7)	(5.2)	(5.1)	-	-	(20.1)
			Net Unutilized Capacity	-	-	-	-	-	-	-	-	-	-	-	-	-
Actual Degree Days		11.	Actual Degree Days													
467.3	685.4		Central Region	813.0	724.1	669.3	352.3	127.4	12.6	4.9	9.3	70.0	230.7	474.2	550.0	4,037.8
436.0	631.5		Niagara Region	758.1	679.1	637.5	330.0	137.6	14.9	5.1	5.8	69.9	203.1	439.6	526.1	3,806.8
554.0	846.4		Eastern Region	895.2	775.3	751.1	381.2	124.0	14.9	10.4	22.0	115.3	260.9	507.7	725.7	4,583.7
		12.	Month end Storage Capacity													
0.84	0.66		% Fill	0.39	0.19	0.14	0.20	0.35	0.49	0.75	0.87	0.97	1.00	0.94	0.78	
			Month end Storage Capacity - Target													
			% Fill	0.47	0.24	0.06	0.07	0.20	0.36	0.56	0.75	0.92	1.00	0.95	0.78	

FRPO INTERROGATORY #9

INTERROGATORY

Gas Costs, Transportation and Storage

Reference: *Exhibit D1, Tab 2, Schedule 1, Page 5 and 6 & Exhibit D1, Tab 2, Schedule 6*

Preamble: In EB-2012-0459, Enbridge provided a response to FRPO letter regarding additional detail on transportation, degree days and UDC risk on February 27, 2014.

Please replicate the same table for Nov. 1, 2014 to October 31, 2015.

RESPONSE

The Company has replicated Table 4 to provide forecasted monthly information for January 2015 to December 2015 including the impact of TCPL tolls effective January 1, 2015.

Please see attached.

Witness: D. Small

Item #	2015 Budget	Column 1	Column 2	Column 3	Column 4	Column 5	Column 6	Column 7	Column 8	Column 9	Column 10	Column 11	Column 12	Column 13	
	PJ's														
		January	February	March	April	May	June	July	August	September	October	November	December		
1.	Forecasted Demand	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	
	Actual Demand	-	-	-	-	-	-	-	-	-	-	-	-		
	Supply														
2.	EGD Contracted Long Haul TCPL Capacity	24.4	22.0	24.4	22.1	22.8	22.1	22.8	22.8	22.1	22.8	17.3	17.8	263.2	
3.	Less Unutilized Capacity	-	-	(9.3)	(9.8)	(8.5)	(8.3)	(8.5)	(8.5)	(8.6)	(8.8)	(6.0)	(6.2)	(82.5)	
		24.4	22.0	15.1	12.3	14.3	13.8	14.3	14.3	13.5	14.0	11.3	11.6	180.8	
4.	Direct Purchase Own Transportation	8.9	8.0	8.9	8.6	8.9	8.6	8.9	8.9	8.6	8.9	8.6	8.9	104.8	
5.	Alliance/Vector	9.0	8.1	9.0	8.7	9.0	8.7	9.0	9.0	8.7	9.0	8.7	5.7	102.6	
6.	Dawn Discretionary	4.0	4.0	-	0.0	0.0	3.0	3.1	3.1	3.0	3.1	-	3.1	26.4	
7.	Peaking Supplies	0.3	-	-	-	-	-	-	-	-	-	-	-	0.3	
	Niagara Supplies	-	-	-	-	-	-	-	-	-	-	6.0	6.2	12.2	
	Total Supply	46.5	42.2	33.0	29.6	32.2	34.1	35.3	35.3	33.8	35.0	34.6	35.6	427.1	
8.	Storage Requirement	23.4	18.8	20.8	3.7	(11.3)	(19.4)	(21.8)	(21.9)	(18.8)	(7.7)	7.1	25.0	(2.1)	
	Total Supply	70.0	61.0	53.8	33.3	20.9	14.7	13.4	13.3	15.0	27.3	41.7	60.6	424.9	
9.	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	
		-	-	18.6	20.0	17.0	17.0	17.0	17.0	17.6	17.6	12.3	12.3	166.4	
	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	
10.	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	
		-	-	9.3	9.8	8.5	8.3	8.5	8.5	8.6	8.8	6.0	6.2	82.6	
	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	82.6	
11.	Forecasted 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
12.	Month end Storage Capacity														
	% 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		

FRPO INTERROGATORY #10

INTERROGATORY

Gas Costs, Transportation and Storage

Reference: *Exhibit D1, Tab 2, Schedule 1, Page 9 of 11*

Historically, how did Enbridge determine the date for which full storage deliverability would be maintained i.e., the specific date each year between the end of January and early February?

RESPONSE

The Company's gas supply planning process uses a statistically determined set of weather conditions to establish a demand profile. These weather conditions take into consideration historical weather trends and include design criteria that account for weather variability on peak day and near peak day conditions based on an assumed level of risk. These peak day and near peak day design conditions are called the "Multipeak Design Criteria". Other than peak day and multipeaks, conditions over the remainder of the winter period are based on historical averages resulting in a higher assumed level of risk for the winter period as a whole. Once the demand profile is determined according to the design weather conditions it is input into a linear programming model called SENDOUT. SENDOUT is also provided with a menu of supply points and prices and storage and transportation alternatives and associated costs. SENDOUT develops a least cost optimal gas supply portfolio based on these inputs.

The gas supply portfolios determined by SENDOUT can vary year over year depending on the demand profile as well as the supply, storage and transportation alternatives that are being evaluated. Historically, storage deliverability targets were determined by SENDOUT such that peak and multi-peak demands were met. This meant that storage deliverability at any point in time was determined according to the demand profile for each year. As a result, there was no specific date associated with maintenance of full storage deliverability. This is in contrast to the Company's proposal which imposes specific dates and deliverability targets into the gas supply plan rather than letting SENDOUT choose what those dates will be. From a modelling perspective the historical design criteria would generally allow for storage deliverability declines below 100% sometime near the end of January or the beginning of February. Given that the modelling assumes normal historical average weather this approach has proven to be effective during periods of average or near average weather conditions. However, as was experienced during the winter of 2013/14, during prolonged colder than normal weather conditions it left the Company acquiring significant incremental supplies to meet demand.

FRPO INTERROGATORY #11

INTERROGATORY

Gas Costs, Transportation and Storage

Reference: *Exhibit D1, Tab 2, Schedule 1, Page 9 of 11*

Please provide the date or range of dates in the 2015 plan.

RESPONSE

Please see Exhibit D1, Tab 2, Schedule 1, page 9, paragraph 22.

Witness: D. Small

FRPO INTERROGATORY #12

INTERROGATORY

Gas Costs, Transportation and Storage

Reference: *Exhibit D1, Tab 2, Schedule 1, Page 9 of 11*

Please provide the standard percentage full the storage must be maintained to secure firm deliverability.

RESPONSE

In order to maintain maximum deliverability from storage the Company must maintain storage balances at a fill percentage of approximately 38% of capacity. This fill percentage is based on the storage facilities and storage contracts underpinning the determination of 2015 gas costs.

Witness: D. Small

FRPO INTERROGATORY #13

INTERROGATORY

Gas Costs, Transportation and Storage

Reference: *Exhibit D1, Tab 2, Schedule 1, Page 10 of 11*

Preamble: Enbridge states:

> *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*

Will Enbridge be documenting these decisions, the alternatives considered and the data available that was relied upon in these decisions?

a. If so, how?
b. If not, why not?

RESPONSE

Yes.

a) Gas supply personnel meet on a regular basis (typically weekly) throughout the year to discuss short term operational requirements. The purchasing decisions described above are part of these discussions and these discussions are documented. The response to Board Staff Interrogatory #11 at I.D1.EGDI.STAFF.11 identifies, at a high level, the decision making process involved in reviewing medium term weather forecasts.

b) N/A.

Witness: D. Small

FRPO INTERROGATORY #14

INTERROGATORY

Gas Costs, Transportation and Storage

Reference: *Exhibit D1, Tab 2, Schedule 4, Page 1 of 2*

Please provide the methodology used to allocate Niagara cost between commodity, transport and load balancing (if there is a component of localized load balancing).

RESPONSE

As discussed in the response to FRPO Interrogatory #2 at Exhibit I.D1.EGDI.FRPO.2, the Company uses an Empress reference price to design its gas supply charge, and any price premium for gas supplies purchased at other supply hubs – such as Chicago or Dawn – over the Empress reference price is classified as Transportation.

In Exhibit G2, Tab 6, Schedule 2, page 1, Line 1.8, it can be identified that Niagara Supplies are classified as Commodity ($46.6 million, as seen in Col. 3) and Transportation ($5.6 million, as seen in Col. 9). The Commodity amount in Column 3 is determined by pricing all Niagara volumes (in Col. 1) at the Empress reference price (in Col. 2). The total cost of Niagara supplies (in Col. 11) less the amount classified as Commodity (in Col. 3) is classified as Transportation cost (in Col. 9).

Witnesses: A. Kacicnik
M. Kirk

BOARD STAFF INTERROGATORY #3

INTERROGATORY

Gas Costs, Transportation, and Storage

Ref: ExD1/T2/S1/para 2

The Company states that:

"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."

Has the Company considered purchasing any of its gas on a fixed price basis? Please discuss the advantages and disadvantages of such an approach.

RESPONSE

The current process utilized by the Company for gas acquisition incorporates fixed price contracts for some of the gas it procures during the course of the year. Below is a brief description of the process the Company follows for its gas supply acquisition.

Once the forecasted supply portfolio for the upcoming test year has been developed, the Company will determine the amount of a particular supply source to be purchased on an annual, seasonal, monthly or daily basis. RFPs are sent out for annual, seasonal and monthly supplies for a volume to be delivered by suppliers on a daily basis. Pricing provided by suppliers in their responses to these RFPs are generally tied to a particular index (i.e., NGI Chicago Monthly, AECO 5a, CGPR monthly, etc). Suppliers will generally provide a range of responses indicating they are prepared to sell gas to EGD for a specified term based on certain pricing parameters which typically includes index pricing. These responses also tend to include a premium or a discount to the underlying index.

As an example, for annual supply the Company typically receives responses tied to a monthly index. The monthly index is usually based upon the market price for that supply determined over a five day period before the actual month when gas is expected to flow. In this way the price paid by EGD for the gas procured is fixed for the month.

In other instances, for example a monthly supply requirement, the Company may agree to procure gas from a supplier based on daily index pricing.

Witness: D. Small

In addition to annual, seasonal and monthly contracts, the Company also secures "rest of month" and daily volumes that are executed at fixed prices (i.e., at a price that is determined and agreed to by EGD and the supplier at the time of execution; there is no "settlement" period or market averages at play). In this instance the Company will generally contact suppliers directly.

This diversity of pricing mechanisms, fixed and variable, protects ratepayers from pricing swings. In a rising market, the monthly indexes (which are settled prior to the start of the month) will provide lower pricing compared to daily index transactions, while daily index deals will be below the monthly indexes in a falling market. The volumetric/operational flexibility required by the Company, due to the nature of the demand profile it faces, dictates that a mix of short and longer term contracts be executed and ultimately, that a balance of fixed and variable pricing be applied.

In terms of procuring natural gas under fixed price contracts for annual supply, the Company could do so in a number of ways.

One option would be to try and get fixed pricing through the RFP process. However, through this option there is no guarantee that EGD would receive responses for fixed pricing and there is no guarantee that any responses for fixed pricing would be acceptable. During periods of price volatility or an expectation of price volatility, suppliers may not be willing to take on the additional risk of price exposure. The Company suspects that suppliers would only be willing to bear that risk if their supply is hedged either physically or financially (which will also increase cost). Consequently, suppliers may not bid or may only offer supply based on a daily index.

A second option would be for the Company to contact suppliers directly seeking a fixed priced contract. The Company's experience has been that suppliers are reluctant to take on the associated risk of a longer term fixed price contract (i.e., one year) as it is a more complicated and time-sensitive execution.

Finally, the Company could utilize a gas supply risk management program of its own whereby the price for supply in a particular forward month can be locked into using a financial instrument. EGD does not operate a hedging program pursuant to the Board's Decision in EB-2006-0034 in which EGD was directed to cease gas supply risk management activities.

EGD's options to procure natural gas under fixed price contracts is dependent on the willingness of counterparties to offer such arrangements which in turn is dependent on a number of factors including but not limited to market conditions and expectations at a point in time.

Witness: D. Small

BOARD STAFF INTERROGATORY #4

INTERROGATORY

Gas Costs, Transportation, and Storage

Ref: ExD1/T2/S1/para 3

The table in paragraph 3 shows the 2015 Test Year acquisition volumes by contract type including the supply area.

Please expand the table to include a comparison to the prior two Test Years (2014 and 2013). Please provide the information is both absolute and relative terms.

RESPONSE

The attached is an expanded version of Exhibit D1, Tab 2, Schedule 8 and compares the 2015, 2014 and 2013 Budget supply and demand volumes in both 10^3m^3 and in Bcf. It also provides the percentage of supply by the various supply sources.

Witness: D. Small

Gas Supply/Demand Balance

Item #		Col. 1 2015 Budget 10^3m^3	Col. 2 2015 Budget BCF	Col. 3 % of Supply	Col. 4 2014 Budget 10^3m^3	Col. 5 2014 Budget BCF	Col. 6 % of Supply	Col. 7 2013 Budget 10^3m^3	Col. 8 2014 Budget BCF	Col. 9 % of Supply
1.	Total Demand	11,275,584.4	398.0		11,232,185.0	396.5		11,576,371.2	408.7	
	Deliveries									
2.1	Western Canadian Supplies	4,783,328.8	168.9		4,832,969.2	170.6		3,956,849.9	139.7	
2.2	Less TCPL Fuel Requirement	(150,375.9)	(5.3)		(79,219.9)	(2.8)		(70,759.0)	(2.5)	
		4,632,952.9	163.5	0.41	4,753,749.3	167.8	0.42	3,886,090.9	137.2	0.33
2.3	Peaking/Seasonal	7,750.7	0.3	0.00	36,068.0	1.3	0.00	37,998.7	1.3	0.00
2.4	Ontario Production	730.0	0.0	0.00	730.0	0.0	0.00	730.0	0.0	0.00
2.5	Chicago Supplies	1,843,671.0	65.1	0.16	1,847,142.8	65.2	0.16	1,832,109.7	64.7	0.16
2.6	Delivered Supplies	700,451.1	24.7	0.06	932,827.1	32.9	0.08	1,553,462.5	54.8	0.13
2.7	Niagara Supplies	323,693.3	11.4	0.03	-	0.0	-	-	0.0	-
		7,509,249.0	265.1		7,570,517.3	267.2		7,310,391.8	258.1	
2.8	Direct Purchase Delivery	3,823,270.8	135.0	0.34	3,742,271.6	132.1	0.33	4,383,689.4	154.7	0.37
	Total Supply	11,332,519.8	400.0		11,312,788.9	399.4		11,694,081.2	412.8	
2.9	Storage (Injection)/Withdrawal	(56,935.4)	(2.0)		(80,603.8)	(2.8)		(117,710.0)	(4.2)	
2.	Total Delivery	11,275,584.4	398.0		11,232,185.0	396.5		11,576,371.2	408.7	

Total Demand includes both System Sales and T-Service Consumption

BOARD STAFF INTERROGATORY #5

INTERROGATORY

Gas Costs, Transportation, and Storage

Ref: ExD1/T2/S1/para 8

Paragraph 8 makes mention of possible future transportation paths.

"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."

Please elaborate on the future gas supply paths contemplated. For example would they include volumes on the proposed Nexus pipeline? Would it also include new volumes acquired at the Niagara/Chippewa and Iroquois import points?

RESPONSE

The Company is always looking for opportunities that will allow it to diversify its gas supply portfolio. The future gas supply paths that the Company is contemplating include any existing or new pipelines that would allow increased access to gas supply options.

The future gas supply paths contemplated would include the proposed Nexus pipeline which has an expected in-service date of November 1, 2017. As the Marcellus and Utica shale supply area continues to develop the Company expects producers will explore opportunities to sell their gas in a number of market areas. For those producers targeting the Ontario market this would likely include using Iroquois and/or Niagara/Chippewa as import points.

The Company will continue to monitor the developments in these areas in order to remain informed about potential new supply opportunities.

Witness: D. Small

BOARD STAFF INTERROGATORY #6

INTERROGATORY

Gas Costs, Transportation, and Storage

Ref: ExD1/T2/S1/para 11

In paragraph 11 the Company states that with respect to peaking services:

“The Company has chosen to maintain the same level of Peaking Services for 2015 as was forecast for 2014.”

Please provide a detailed explanation together with the analysis supporting the decision to maintain the same level of peaking service as 2014. What were the alternatives considered and why were they rejected in favour of the plan chosen?

RESPONSE

During the System Reliability proceeding (EB-2010-0231) the Company discussed the rationale for reducing the level of contracted Peaking Service. The primary reason was that peaking services had proven to be less than firm in extreme weather/system outage situations and therefore there needed to be an increase in system reliability. This increase in system reliability could be accomplished by reducing reliance on peaking supplies delivered through lower priority discretionary services.

The Company incorporated the outcomes of the System Reliability Settlement Agreement as a part of its Gas Supply plan for 2012. Since then, the Company has maintained the same levels of Peaking Service within its gas supply plan for 2013, 2014 and 2015. The primary reason for maintaining these levels of peaking supplies is due to a lack of alternative transportation paths to the Company’s franchise area as a substitute for peaking service. The only viable alternative would have been for the Company to contract for an equivalent level of long haul firm transportation on TransCanada.

As discussed during the EB-2012-0451 proceeding, upon the completion of the GTA Project the Company will be able to satisfy its CDA peak day requirements without the need to contract for peaking service. Further the Company expects that for the 2017/2018 winter it will be able to satisfy EDA peak day requirements without the need to contract for peaking service.

Witness: D. Small

BOARD STAFF INTERROGATORY #7

INTERROGATORY

Gas Costs, Transportation, and Storage

Ref: ExD1/T2/S1/para 12

In paragraph 12 the Company states that it will look for alternative transport of gas to its franchise.

"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."

If such transport alternatives are found and subsequently implemented, how does the Company intend to inform the Board and seek approval during the course of the Test Year? Alternatively, does the Company believe it requires the flexibility to be able to contract for new transport if it feels that such action is appropriate?

RESPONSE

The Company believes that it requires flexibility when it comes to transportation contracting. When transportation alternatives become available these opportunities typically need to be acted upon quickly. Transportation alternatives made available in the secondary market or through open seasons often require decisions to be made within a few weeks and in some cases within a few days.

If transportation alternatives arise during 2015 that are a benefit to ratepayers, the Company believes those alternatives should be pursued. If the resultant contractual commitments of an alternative are for less than one year the Company believes it has the required flexibility to incorporate these alternatives as a part of the management of its gas supply plan in 2015. The Board would be informed of such decisions during the QRAM process.

The Company also requires flexibility to enter into other short term obligations (between one and five years) and other arrangements for more than one year without prior approval. The merits of such transactions will be discussed with interested parties at the Company's annual Stakeholder Conference or through the evidentiary phase of a Rate Adjustment Application for the subsequent test year.

Witness: D. Small

BOARD STAFF INTERROGATORY #8

INTERROGATORY

Gas Costs, Transportation, and Storage

Ref: ExD1/T2/S1/para 14

With respect to the expected $130 million in UDC, the Company indicates that it will use "best efforts" to mitigate the UDC costs.

What is the Company's strategy to address UDC? Please outline the detailed plans for UDC mitigation. How does the Company intend to communicate UDC costs, and mitigation efforts, during the course of the year?

RESPONSE

Included within the Company's 2015 gas cost forecast is a purchase of 15.3 Bcf of discretionary supplies acquired at Dawn for the purposes of filling storage next summer. If during the summer the Company does require incremental supply to fill storage then rather than acquire gas at Dawn the Company will acquire gas in western Canada and maximize the unutilized capacity to the extent possible. If there is capacity that remains unutilized, and market conditions are conducive, the Company will release the capacity to third parties in an effort to generate revenue to offset the costs of the unutilized capacity. This is similar to the approach taken by the Company in 2014 to mitigate the impacts of UDC costs.

Included in its pre-filed Gas Costs, Transportation and Storage evidence the Company provided a schedule that identifies the forecasted monthly breakdown of the expected $130 million in UDC (Exhibit D1, Tab 2, Schedule 1, Appendix A). This schedule was based upon the TCPL tolls in effect prior to January 1, 2015. Based upon the TCPL Interim Mainline Transportation Tolls and Interim Abandonment Surcharges the Company has updated Exhibit D1, Tab 2, Schedule 1, Appendix A resulting in forecasted UDC of $166.4 million. The Company has also updated its pre-filed evidence at Exhibit D1, Tab 2, Schedule 1, page 6, paragraph 15 and at Exhibit D2, Tab1, Schedule 1, page 23, paragraph 77 to reflect the change as well. Similar to 2014 the Company intends to file, on a monthly basis, an update to this schedule which will show the amount of unutilized capacity and the associated costs offset by any revenues generated by the Company through releasing that capacity to third parties. This information will provide the Board and Intervenors with frequent updates throughout the year.

Witness: D. Small

BOARD STAFF INTERROGATORY #9

INTERROGATORY

Gas Costs, Transportation, and Storage

Ref: ExD1/T2/S1/para 15

Please provide the cost / benefit analysis that underpins the decision to not renew the Alliance / Vector contracts and to contract for new supply at the Niagara / TCPL interconnect.

RESPONSE

The primary 15-year term for Alliance capacity set to expire November 30, 2015, required a 5-year notification in November 2010. At the time of the evaluation in 2010, the forecasted landed costs analysis of comparative paths to the CDA for 2016 (accounting for commodity, tolls, fuel) showed that Alliance was the ***least*** economic option (comparative paths included Chicago/Vector, short and long haul on TCPL, Dawn, Gulf of Mexico/ANR and Rockies). The Revenue Shortfall Rate (the per unit charge for all non-renewing shippers) was forecast to be less than the expected gas costs if Alliance transport was renewed as part of the 2016 portfolio.

In addition to the economic considerations, the “value” in renewing Alliance capacity was downgraded by a number of additional factors, including:

- Renewal bids would be “all or nothing”; there was no flexibility in terms of renewing partial volumes that might better fit an evolving supply portfolio;
- At the time of renewals, the market seemed poised for sizable non-renewals which opened the door for new contracting opportunities and potentially increased leverage for shippers assessing December 2015 transportation options outside of the initial renewal process;
- The 5 year notification restricted portfolio flexibility in a growing/dynamic marketplace.

In the end, it was determined that renewal of Alliance capacity beyond 2015 provided neither economic nor strategic advantages for the Company. The decision was made in November 2010 to not renew the 75MMcf/day of Alliance transportation beyond November 30, 2015.

Witness: D. Small

The Company's two original 15-year contracts on Vector Pipeline totaling 175,000Dth/day (and the corresponding Canadian capacity) expire at the end of November 2015. The decision around contract extensions/non-renewal required a three year notification and had to be rendered by November 30, 2012. In reviewing its options, the Company found the best combination of flexibility, cost and portfolio security was met with a "rolling" one year renewal on the two transport contracts. The following considerations supported this decision:

- Vector capacity is a critical component of the Company's supply strategy, feeding short haul contracts to Parkway, CDA and EDA which are used extensively in the winter to serve franchise area demand. During the summer, the capacity serves to fill storage;
- Chicago/Vector gas provides significant supply diversity (from a reliable hub) and offsets growing reliance on Dawn;
- CDA-landed supply from Chicago has a significant price advantage over TCPL long haul options;
- With a one-year renewal, the Company retains the right of first refusal and secures the same recourse rate ($0.25US/Dth) currently being paid (this rate is part of the existing Tariff and does not require FERC approval).

The decision to enter into a rolling one-year renewal has provided the Company with the opportunity to regularly re-evaluate its needs/portfolio in light of rapidly changing markets and infrastructure.

The Company responded to TCPL's 2013 New Capacity Open Season (NCOS) with a bid for 200,000GJs/day of transportation capacity from the Niagara Falls receipt point to the proposed Parkway Enbridge CDA (15 year term with an in-service date of November 1, 2015). The bid was underpinned by the following considerations:

- The new capacity will displace a portion of long haul, discretionary and unsecured supplies by aligning with the approved Greater Toronto Area Project (GTAP).
- The expected gas supply savings were provided as part of the overall benefits discussed in the GTA proceedings.
- The capacity will also provide the Company and its customers with greater diversity of supply (accessing the emerging US Northeast markets including the Marcellus shale formation) and increased reliability (the service is firm; delivered and peaking contracts do not guarantee firm transport).

As with the Alliance and Vector renewal decisions detailed above, the Company believes that contracting for new capacity out of Niagara aligns with gas supply principles aimed at supply reliability, diversity of supply sources and transportation paths, planning and operational flexibility as well as cost minimization for the ratepayers.

Witness: D. Small

BOARD STAFF INTERROGATORY #10

INTERROGATORY

Gas Costs, Transportation, and Storage

Ref: ExD1/T2/S1/para 22

In paragraph 22 the Company describes its decision to change how it manages storage balances in the later months of the winter season.

"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."

a) Will incremental storage be required to achieve the increased deliverability? Please explain how the Company's storage balance proposal would be implemented. In the explanation, please include the cost / benefit analysis underpinning the proposal.

b) Please discuss the risks and trade-offs associated with the storage balance proposal. Please also provide a sensitivity analysis showing the cost consequences of the storage proposal if the weather is warmer than normal, or colder than normal.

RESPONSE

a) Incremental storage capacity is not required to achieve increased deliverability later into the winter.

   The method used to determine the 2015 storage deliverability targets is provided in the reference above and further discussed in the response to Board Staff Interrogatory #12 b) at Exhibit I.D1.EGDI.STAFF.12. The response to FRPO Interrogatory #10 at Exhibit I.D1.EGDI.FRPO.10 discusses and contrasts the method of determining storage balances and storage deliverability under the Company's old design criteria and the proposed design criteria.

Witness: D. Small

The 2015 storage deliverability targets are forecast to be maintained through an increase in forecasted supply purchases in the winter period and a subsequent decrease in forecasted supply purchases later in the year. The shifting of supply purchases in this manner will reduce forecast storage withdrawals early in the winter thereby maintaining higher forecast storage inventory, and subsequently higher storage deliverability, later into the winter season. The decision to procure the necessary supplies will be made by the Company in conjunction with the other procurement decisions required to execute the 2015 gas supply plan.

The cost associated with the new storage deliverability targets is forecast to be $12 million as set out in the calculations included in Attachment 1 to this response. The estimated cost includes $2 million in carrying costs for the incremental gas in storage required to achieve the 2015 storage deliverability targets and $10 million related to shifting supply purchases to higher priced winter months.

The carrying costs were determined by estimating the incremental gas in storage that would result from the higher storage balances required in the winter season to achieve the new storage deliverability targets. This was estimated through a comparison of the 2014 and 2015 storage level targets since the variance is primarily due to the new storage deliverability targets.

The analysis then assumes that the incremental gas in storage is valued at the Dawn prompt month average index price measured over a 21 day period from August 1, 2014 to August 29, 2014. This assumption is consistent with the methodology used for gas costing in this 2015 Rate Adjustment Application[1]. A carrying cost of 7.81%[2] was used to determine the value of the incremental gas in storage.

The cost associated with shifting some of the supply purchases to the winter months was determined through the storage injections and withdrawals that were derived from the storage balances used in the carrying cost calculation. This approach assumes that any variances would be accounted for through incremental or reduced supply purchases at Dawn. Although some of the incremental supply purchases may be made at other points such as Empress, this portion of the analysis is predicated on the variance between prompt month prices which are reasonably represented by Dawn

Because of the manner in which gas costs are calculated for purposes of the 2015 Rate Adjustment Application (i.e., 2015 forecasted supplies are costed at the prices which underpin the October 2014 QRAM Reference Price) there is no impact on the

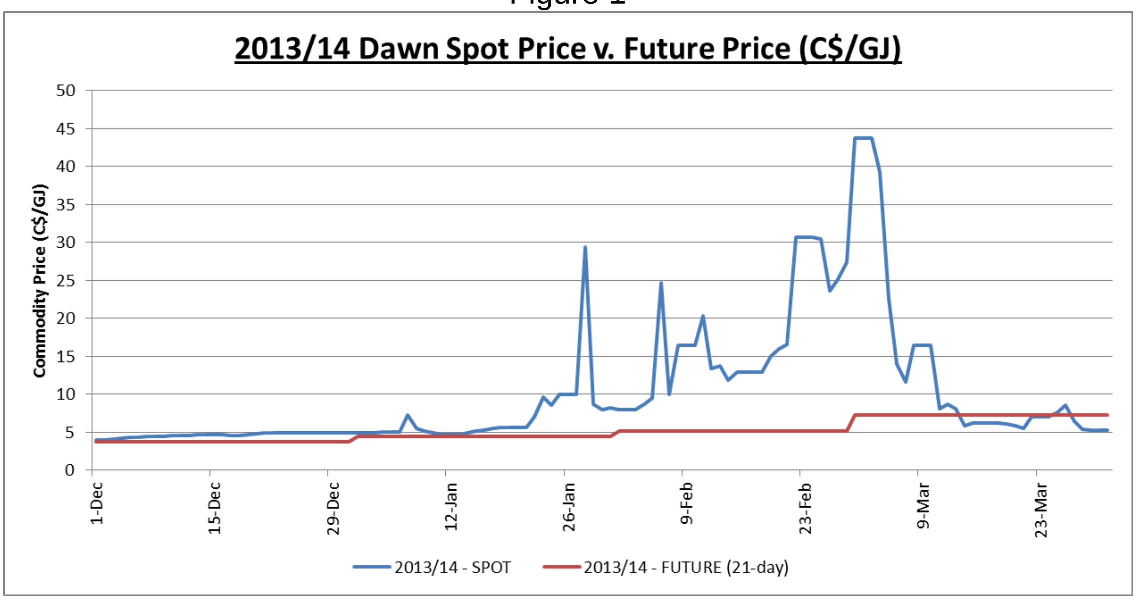
[1] EB-2014-0276 Exhibit D1, Tab 2, Schedule 7, page 1 of 1
[2] EB-2014-0348 Exhibit Q1-3, Tab 2, Schedule 3, page 1 of 1

2015 gas cost in the 2015 Rate Adjustment Application as explained in the response to Board Staff Interrogatory #12 a) at Exhibit I.D1.EGDI.STAFF.12.

The benefit associated with the storage targets being used in 2015 is the potential to mitigate incremental gas supply costs during periods of higher than budgeted demand and/or pricing conditions. The specific value of the benefit will depend on actual conditions that are experienced over the course of the test year.

During periods of near or lower than budgeted demand and/or pricing conditions the benefit of the 2015 storage deliverability targets would be negligible. However, during periods of higher than budgeted demand and/or pricing conditions, there would be potential for gas cost savings. A recent example where demand and pricing conditions were higher than budgeted was the winter of 2013/2014. During that winter season incremental supplies were required, much of which had to be purchased in the daily spot market to offset high demand and supplement storage deliverability from rapidly depleting storage inventories. As seen in Figure 1, the daily spot prices were much higher than the prompt month prices.

Figure 1



The 2015 storage deliverability targets shift some supply purchases to the winter months. These supplies can then be procured proactively in the prompt month market rather than on the day or intra-month as was experienced in the winter of 2013/2014. The potential benefit of purchasing the supplies in this manner has been estimated to be $143 million when 2013/2014 demand and market conditions are used as an approximation. In warmer years and/or when there is not much pricing variability, the benefit will be negligible. However, should demand and prices exceed forecast levels the benefit could be substantial depending on market conditions at the time.

b) The risks and trade-offs associated with the storage balance proposal were discussed by the Company in the 2014 Natural Gas Market Review Stakeholder Conference through a presentation and written comments that were submitted to the Board. The Company discussed how the level of risk assumed in the design criteria will impact the gas supply plan budget and subsequent execution costs in a situation where natural gas demand variances to budget are high. The budget costs refer to costs forecasted to be required to procure the storage, transportation, and supply assets necessary to meet design weather conditions. The execution costs refer to the costs required to procure additional storage, transportation, and/or supply assets when the gas supply plan is executed under actual weather conditions. The relation between the level of risk assumed in the design criteria and the impact that demand variances have on the budget and execution costs are summarized in Table 1.

Table 1: Design Criteria Impact on Gas Supply Plans

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

By maintaining the storage deliverability targets later into the winter season for 2015, the execution of the gas supply plan is more conservative which would result in higher budget costs and lower execution costs, as discussed in part a) above, should actual demand be higher than budgeted demand.

The sensitivity analysis is discussed in part a) above.

Attachment 1 – Cost Benefit Analysis for 2015 Storage Targets

			Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Part 1 - Storage Balance Analysis																
	2015 Budget Storage Balances															
[1]	2015 Storage Target	Bcf	82.42	60.56	42.57	22.64	19.08	29.56	47.69	68.06	88.50	106.01	113.00	106.21	82.42	
[2]	2014 Storage Target	%	0.78	0.47	0.24	0.06	0.07	0.20	0.36	0.56	0.75	0.92	1.00	0.95	0.78	
[3]	Maximum Storage Balance	Bcf	113.00	113.00	113.00	113.00	113.00	113.00	113.00	113.00	113.00	113.00	113.00	113.00	113.00	
[4] = [2] x [3]	2014 Storage Target	Bcf	88.14	53.11	27.12	6.78	7.91	22.60	40.68	63.28	84.75	103.96	113.00	107.35	88.14	
	2015 Budget Storage Balances															
[5] =[1] x 0.028328 x 37.69	2015 Storage Target Criteria	PJ	87.99	64.66	45.45	24.18	20.37	31.56	50.92	72.66	94.49	113.18	120.65	113.40	87.99	
[6] =[4] x 0.028328 x 37.69	2014 Storage Target Criteria	PJ	94.11	56.70	28.96	7.24	8.45	24.13	43.43	67.56	90.49	111.00	120.65	114.62	94.11	
Part 2 - Carrying Cost Analysis																
	Carrying Cost of Gas in Storage															
[7] = [5] - [6]	Incremental Gas In Storage	PJ		7.96	16.50	16.94	11.93	7.43	7.48	5.10	4.01	2.19	(0.00)	(1.21)	(6.11)	
[8]	21 Day Average Dawn Price	CDN$/GJ		4.74	4.75	4.71	4.23	4.17	4.18	4.21	4.17	4.18	4.24	4.47	4.58	
[9]	Carrying Cost	%		7.81%	7.81%	7.81%	7.81%	7.81%	7.81%	7.81%	7.81%	7.81%	7.81%	7.81%	7.81%	
[10] = [7] x [8] x [9] / 12	Carrying Cost of Gas in Storage	$M		0.25	0.51	0.52	0.33	0.20	0.20	0.14	0.11	0.06	(0.00)	(0.04)	(0.18)	2.10
Part 3 - Monthly Spread Cost Analysis																
	2015 Budget Net Injections/(Withdrawal)															
[11] = $[5]_{(month -1)}$ - $[5]_{(month)}$	2015 Storage Target Criteria	PJ		(23.33)	(19.21)	(21.27)	(3.80)	11.19	19.35	21.74	21.83	18.69	7.46	(7.24)	(25.41)	-
[12] = $[6]_{(month -1)}$ - $[6]_{(month)}$	2014 Storage Target Criteria	PJ		(37.40)	(27.75)	(21.72)	1.21	15.68	19.30	24.13	22.92	20.51	9.65	(6.03)	(20.51)	-
	Purchased Supply Costs/(Benefits)															
[13] = [11] - [12]	Incremental/(Reduced) Supply	PJ		14.07	8.54	0.44	(5.01)	(4.49)	0.05	(2.38)	(1.09)	(1.82)	(2.19)	(1.21)	(4.90)	-
[14] = [8]	21 Day Average Dawn	CDN$/GJ		4.74	4.75	4.71	4.23	4.17	4.18	4.21	4.17	4.18	4.24	4.47	4.58	
[15] = [13] x [14]	Purchased Supply Costs/(Benefits)	$M		66.66	40.56	2.09	(21.20)	(18.76)	0.20	(10.03)	(4.55)	(7.62)	(9.26)	(5.41)	(22.41)	10.27
Part 4 - Total Cost Analysis																
[16] = [10]	Carrying Cost of Gas in Storage	$M		0.25	0.51	0.52	0.33	0.20	0.20	0.14	0.11	0.06	(0.00)	(0.04)	(0.18)	2.10
[17] = [15]	Purchased Supply Costs/(Benefits)	$M		66.66	40.56	2.09	(21.20)	(18.76)	0.20	(10.03)	(4.55)	(7.62)	(9.26)	(5.41)	(22.41)	10.27
[18] = [16] + [17]	Total Cost/(Benefit)			66.91	41.07	2.60	(20.87)	(18.56)	0.41	(9.89)	(4.44)	(7.56)	(9.26)	(5.45)	(22.60)	12.37
Part 5 - Execution Benefit Analysis																
	Sensativity Analysis															
[19] = [13]	Incremental/(Reduced) Supply	PJ		14.07	8.54	0.44										
[20]	2014 21 Day Average Dawn	CDN$/GJ		4.40	5.20	7.29										
[21]	2014 Monthly Average Dawn Spot	CDN$/GJ		7.07	17.26	13.10										
[22] = [20] - [21]	Cost Variance	CDN$/GJ		(2.68)	(12.06)	(5.82)										
[23] = [19] x [22]	Purchased Supply Cost/(Benefit)	$M		(37.63)	(102.94)	(2.58)										(143.15)

Witness: D. Small

BOARD STAFF INTERROGATORY #11

INTERROGATORY

Gas Costs, Transportation, and Storage

Ref: ExD1/T2/S1/para 23

In paragraph 23 the Company mentions that it will investigate, and may take into account in its demand assessment, medium term weather forecasts in the current winter season. It further states that the cost consequences of such actions will be reflected in the PGVA.

What would trigger Enbridge to include in its demand assessment the medium term weather forecast? Please provide further details on how this discretion would be exercised.

RESPONSE

Gas Supply personnel meet on a weekly basis throughout the winter (and more frequently if required) to discuss operational requirements. These discussions take into consideration the demand forecast for the upcoming week based on a seven day weather forecast while assuming budgeted demand for the remainder of the winter. Forecasts going further into the future have been reviewed, however, in past years these forecasts were never used to plan purchases given the uncertainty associated with longer term forecasts.

As a result of the various discussions held throughout 2014 surrounding the QRAM process and leading up to and including the Natural Gas Market Review, the Company explored how it could incorporate medium term weather forecasts as a part of its weekly planning process. Given the forecasting uncertainty associated with these forecasts, the Company believes a conservative approach must be taken as it begins to factor these forecasts into its procurement decisions. Enbridge has maintained this conservative approach as it has begun to make some use of medium-term weather forecasts in its demand assessments for the winter of 2015.

For example, early in January 2015 two independent forecasters were calling for colder than budget temperatures in February predicting an average daily additional requirement of approximately 300 TJs per day. Taking this into consideration, the Gas Supply personnel decided to include 100 TJs of this additional requirement as part of its RFP for February supply as a part of its gas supply plan. At subsequent meetings, the group reviewed updated forecasts and continued to firm up additional supplies as February approached as well as during the month as it unfolded.

The risk of such an approach is that if the Company does acquire these supplies for a forward month and then demand does not materialize, the Company will be faced with higher gas in storage balances and will have to back off forecasted purchases in the summer. Therefore the Company would only look to acquire additional supplies if the predicted incremental demand is significant and not if the medium-term forecasts were calling for a small increase in demand.

BOARD STAFF INTERROGATORY #12

INTERROGATORY

Gas Costs, Transportation, and Storage

Ref: ExD1/T2/S1/para 24

In paragraph 24 the Company speaks to the maintenance of higher storage balances later in the winter season.

"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."

a. Board staff is interested to assess the cost impact of the move to the higher storage balances. Please recast the "Summary of Gas Cost to Operations" schedule for 2015 (D1/T2/S4) to reflect a scenario assuming no change to the winter season storage target balance levels.

b. Please explain why the Company is acting now to implement changes to its Gas Supply Plan as opposed to awaiting the outcome of the Natural Gas Market Review and the second phase of the QRAM Review.

RESPONSE

a) As per the Board's approved methodology, the 2015 Summary of Gas Costs to Operations was prepared by applying the prices for each supply source that underpin October 2014 QRAM to the 2015 supply portfolio. Because the total supply portfolio for the year will not change (i.e., shifting purchases from winter to summer) the forecasted cost for 2015 will not change. Therefore there is no impact on the 2015 forecasted gas costs within the noted exhibit.

b) Given the magnitude of the costs that ratepayers were exposed to last winter as a result of the risk inherent in EGD's previously approved gas supply plans and the concerns raised by the Board and stakeholders the Company did not feel it could wait for the outcome of these processes to begin to act. Further, as the Company understands it, the 2014 Natural Gas Market Review was held in order to provide the

Board with information that will inform its policies as they relate to regulating the market for natural gas in Ontario. The 2014 Natural Gas Market Review was not a process in which participants could make specific proposals and receive specific relief in relation to the gas supply plans of a particular utility.

EGD has spent time since last winter looking at options and approaches to enhancing its gas supply plan to lessen ratepayer exposure to the magnitude of costs experienced in the winter of 2014. Although EGD's preliminary analysis has indicated that new storage capacity would be the most effective option in the long term, there was insufficient time to complete a detailed analysis and secure the necessary storage assets for 2015. The Company therefore sought an interim solution that would help protect ratepayers in a manner that was consistent with the gas supply plans approved by the Board in the past and that would not require significant budget cost increases to implement.

Compared with EGD, Union Gas Limited's ratepayers were not as exposed to high gas prices last year as a result of Union's more conservative supply plan which allowed Union to buy gas largely on a month ahead basis. To reduce EGD's exposure to the spot market for supply, the storage deliverability targets in EGD's 2015 gas supply plan have been aligned in a manner similar to those used in Union's Board approved gas supply plans. These new storage deliverability targets along with placing some reliance on medium-term weather forecasts will result in the Company being able to systematically plan to buy much greater amounts of gas on a month ahead basis.

The Company intends to conduct a more comprehensive analysis of the options for future gas supply plans that would take into consideration the outcomes of the Natural Gas Market Review. The results of these analysis are expected to be communicated to the Board and interested parties in future proceedings.

BOARD STAFF INTERROGATORY #13

INTERROGATORY

Gas Costs, Transportation, and Storage

Ref: ExD1/T2/S4/Summary of Gas Costs to Operations

Please confirm whether or not the Company has based its 2015 gas cost forecasts on the NEB-approved TCPL Mainline Eastern LDC Toll settlement agreement approved by the NEB on November 28, 2014 in its Letter Decision (RH-001-2014). If not, how does it propose that the gas costs be updated to reflect the new tolls?

RESPONSE

The 2015 gas cost forecast was prepared using the various prices that underpinned the October 2014 QRAM and applying them to the 2015 forecasted volumes. Therefore, the 2015 application, as filed, did not include the impact of the NEB-approved TCPL Mainline Eastern LDC Toll settlement agreement approved by the NEB on November 28, 2014 in its Letter Decision (RH-001-2014). However, the impact of the change in TCPL tolls as a result of the TCPL Mainline Eastern LDC Toll settlement agreement was incorporated in EGD's gas cost forecast impacted within the Company's January 2015 QRAM application.

Witness: D. Small

BOARD STAFF INTERROGATORY #14

INTERROGATORY

2015 DSM Forecast Budget

Ref: ExD1/T4/S1/para 5

Please confirm that in the Company's view, the proposed $35 million 2015 DSM budget (which represents an increase relative to the Board-approved 2014 level of $32.2 million) continues to be appropriate in light of the recent issuance of the December 22, 2014 Report of the Board on the DSM Framework covering the years 2015 to 2020 (EB-2014-0134).

RESPONSE

The 2015 DSM budget of $35 million was filed in this proceeding on November 28, 2014. This budget was intended as a placeholder pending the Board's release of its 2015 – 2020 DSM Framework and Filing Guidelines which occurred subsequently on December 22, 2014 ("Framework"). This amount represented an increase of 8.7% over the Board approved 2014 DSM budget of $32.2 million. The 2015 amount was influenced directionally by several matters.

On March 26, 2014 the Minister of Energy issued a Directive to the Ontario Energy Board requiring it to ensure that the gas utilities are achieving all "cost effective" DSM. On September 15, 2014 the Board issued a draft framework which identified key priorities and objectives. Together, these documents signaled that DSM budgets for 2015 and beyond would likely increase. Recognizing that any ramp up in spending would have to be undertaken in a reasonable way reflecting market conditions and current inputs, Enbridge decided that it would be appropriate to build into the 2015 DSM budget some incremental increase over inflation alone. This amount is proposed as a placeholder given that any variance in spending from this amount will be recorded in the DSMVA consistent with the Enbridge 2014 – 2018 Custom IR Plan which was approved by the Board in 2014 (EB-2012-0459).

At section 15.1 on page 37 of the Framework, the Board stated: "The gas utilities should roll-forward their 2014 DSM plans, including all programs and parameters (i.e., budget, targets, incentive structure) into 2015". Enbridge believes that the placeholder budget of $35 million for 2015 is consistent with the requirement of rolling forward its 2014 DSM plan. Indeed, the Board on the same page of the Framework at footnote 25 specifically notes that the Company had updated its 2015 DSM budget amounts as part of this 2015 rate application. The Board did not express any concern in respect of the proposal in this Application for 2015 DSM Budget in the Framework. The Company believes that this indicates that the proposed budget is consistent with the implementation and transitional provisions of the Framework.

The incremental additional dollars in the 2015 DSM budget have been allocated to the Residential Rate 1 customers to account for the relatively higher costs of programming to customers in that market sector. DSM budgets will be the subject of a hearing later in 2015 that will examine the Multi-Year DSM plans of the gas utilities. Until that point, Enbridge believes that the placeholder value of $35 million for 2015 is appropriate.

BOARD STAFF INTERROGATORY #15

INTERROGATORY

Pension / OPEB 2015 Updated Forecast

Ref: ExD1/T5/S1/ Appendix 1 page 1

Page 1 of the October 3, 2014 Mercer letter makes the following statement:

"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."

a) Please explain the above "discretionary contribution of $16,923,682". In the explanation please address why it was needed, the timing, and the anticipated impact on utility ratepayers.

b) Is it EGD's proposal that the discretionary contribution of $16,923,682 would be ratepayer recoverable in 2015?

RESPONSE

a) The discretionary contribution was made in November 2014 and was required to target tax deductibility on the same basis as approved within rates, ensuring that 2014 earnings and resulting earnings sharing were not harmed or reduced through a lack of such contribution. In addition to the 2014 earnings and earnings sharing positive impact which utility ratepayers will see for 2014, the 2015 accrual cost estimate was lowered to the extent that the discretionary contribution would allow for an incremental positive return on assets.

b) No, EGD is not proposing any recovery of the discretionary contribution from ratepayers in 2015 as EGD will continue to be recovering pension and OPEB costs on the accrual basis.

Witnesses: J. Barradas
J. Shem

BOARD STAFF INTERROGATORY #16

INTERROGATORY

Pension / OPEB 2015 Updated Forecast

Ref: ExD1/T5/S1/ Appendix 1 page 6

On page 6 the line showing the 2015 EGD RPP indicates an “Expected Return on Assets” of negative $59.28 million.

Please explain why the Return on Assets projection is negative and include the underlying assumptions that lead to the negative return.

RESPONSE

Page 6 shows the detailed breakdown of the 2015 accrual costs. The first line shows the various accrual cost projections for the EGD portion of the EGD RPP for 2015. Those items that have a negative value are reducing the 2015 accrual costs, and those items with a positive value are increasing the 2015 accrual costs. The Expected Return on Assets amount of $59.28 million is projected to be a positive return on assets rather than a negative return, as it is reducing the overall accrual costs.

Witnesses: J. Barradas
J. Shem

BOARD STAFF INTERROGATORY #17

INTERROGATORY

Pension / OPEB 2015 Updated Forecast

Ref: ExD1/T5/S1

Please provide the most currently available balances in the Post-Retirement True-Up Variance Account for 2014 and 2015.

RESPONSE

The 2014 Post-Retirement True-Up Variance Account ("PTUVA") balance is a $6,220,624 refund to ratepayers.

The 2015 PTUVA balance is currently estimated to be a $398,100 recovery from ratepayers.

Witnesses: J. Barradas
J. Shem

VECC INTERROGATORY #10

INTERROGATORY

Reference: D1/T2/S1/pg.6 /D2/T1

a) Enbridge states that DDCTDA and UDCDA were both used to track UDC amounts. What then was the purpose of the Board establishing both of the accounts? What is the difference between these accounts (i.e. in principle- not dollars)?
b) Please provide the revised description for the UDCDA that is being sought at D2/T1/S1/pg.3

RESPONSE

a) In EB-2011-0354 the Company filed an update to its Peak Gas Day Design Criteria. In the Settlement Agreement for EB-2011-0354 parties agreed to implement the new Peak Gas Day Design Criteria using a phased in approach over the 2013 and 2014 Test Years. The Settlement Agreement included the acceptance of parties that the cost consequences from unutilized transportation costs related to the change in the Design Day methodology would be captured in the 2013 and 2014 Design Day Criteria Transportation Deferral Account. On October 29, 2013 another Settlement Agreement was reached between the Company and interested parties on the Aspects of Enbridge Gas Distributions 2014 Supply Plan. As a part of that Settlement Agreement (EB-2012-0459) parties accepted that there would be other UDC associated with the acquisition of FT capacity (effective November 1, 2013) instead of STFT service. In principle there is no difference between these two accounts as both are meant to capture the costs associated with unutilized FT transportation.

b) A detailed description of the 2015 Unabsorbed Demand Cost Deferral Account (2015 UDCDA) can be found at Exhibit D2, Tab 1, Schedule 1, page 22 of 25.

Witness: D. Small

VECC INTERROGATORY #11

INTERROGATORY

Reference: D1/T2/S1/pgs. 9-11

a) At the above reference the Company has described a number of changes to its gas supply planning in 2015 with respect to the use of storage and medium term weather forecasts. What are the estimated costs/savings that are a result of making these changes?

RESPONSE

For a discussion of the estimated costs and savings from a change to the way that EGD manages storage balances, please see response to Board Staff Interrogatory #10 at Exhibit I.D1.EGDI.STAFF.10.

The estimated costs/savings from the use of medium-term weather forecasts cannot be quantified at this time. It is expected, though, that the use of this approach will lower the Company's gas costs as compared to an approach where procurement decisions do not take such information into account.

Witness: D. Small

VECC INTERROGATORY #12

INTERROGATORY

Reference: D1/T2/S4 & S5

a) Please provide Summary of Gas Cost to Operations and the Summary of Storage & Transportation Costs Tables shown at the above reference to show 2014 year-end costs/volumes.

RESPONSE

The 2014 Summary of Gas Costs to Operations is attached as Schedule 1 and the 2014 Summary of Storage & Transportation Costs are provided as Schedule 2.

The Company is providing this response subject to the comments in EGD's letter of February 26, 2015 which sets out EGD's position as to the relevance of the 2014 actuals information being provided.

Witness: D. Small

SUMMARY OF GAS COST TO OPERATIONS
YEAR ENDED DECEMBER 31, 2014

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	2,276,328.8	401,911.8	176.561	4.685
1.3	Western - @ Nova - TCPL	2,216,967.2	368,705.5	166.311	4.413
1.4	Western Buy/Sell - with Fuel	937.7	158.3	168.821	4.479
1.5	Western - @ Alliance	945,251.0	154,210.3	163.142	4.329
1.6	Less TCPL Fuel Requirement	(186,401.7)	0.0		
1.	Total Western Canadian Supplies	5,253,082.9	924,985.9	176.084	4.672
2.	Peaking Supplies	60,725.5	105,487.4	1,737.118	46.090
3.	Ontario Production	295.1	70.5	238.933	6.339
4.	Chicago Supplies	1,550,168.2	351,540.0	226.775	6.017
5.	Delivered Supplies	2,175,519.1	906,921.0	416.876	11.061
6.	Niagara Supplies	-	-	0.000	0.000
7.	Total Supply Costs	9,039,790.8	2,289,004.8	253.214	6.718
	Transportation Costs				
8.1	TCPL - FT - Demand		268,003.4		
8.2	- FT - Commodity	4,307,831.9	0.0	-	-
	FTSN		4,027.8		
8.3	- Parkway to CDA		0.0		
8.4	- STS - CDA		12,898.1		
8.5	- STS - EDA		9,436.8		
8.6	- Dawn to CDA		10,083.8		
8.7	- Dawn to EDA		18,361.3		
8.8	- Dawn to Iroquois		6,208.7		
8.9	Other Charges		872.9		
8.10	Nova Transmission		8,370.5		
8.11	Alliance Pipeline		45,911.0		
8.12	Vector Pipeline		28,669.4		
8.13	Niagara Falls to Enbridge Parkway CDA		0.0		
8.	Total Transportation Costs		412,843.6		
9.	Total Before PGVA Adjustment	9,039,790.8	2,701,848.3	298.884	7.930
10.	PGVA Adjustment		(842,564.9)		
11.	Total Purchases & Receipt	9,039,790.8	1,859,283.4	205.678	5.457

SUMMARY OF GAS COST TO OPERATIONS
YEAR ENDED DECEMBER 31, 2014

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	9,039,790.8	1,859,283.4	205.678	5.457
12.	Storage Fluctuation	(740,674.5)	(214,496.9)		
13.	Commodity Cost to Operations	8,299,116.3	1,644,786.5	198.188	
14.	Storage and Transportation Costs		97,605.3		
15.	Gas Cost to Operations	8,299,116.3	1,742,391.8	209.949	5.570
16.	T-Service Transportation Costs		71,827.5		
17.	Accounting Adjustments		1,300.0		
18.	2014 Gas Costs	8,299,116.3	1,815,519.3		

SUMMARY OF STORAGE & TRANSPORTATION COSTS
FISCAL 2014

Item #	Units - $(000)	Col. 1 Storage & Transportation Charges Incurred in Fiscal 2014	Col. 2 Fiscal 2014 Storage Charges Recovered in Fiscal 2014	Col. 3 Fiscal 2013 Storage Charges Recovered in Fiscal 2014	Col. 4 Total Storage & Transportation Charges Recovered in Fiscal 2014
	Storage				
1.1	Chatham D	204.6	124.4	66.5	190.9
1.2	Injection	817.9	151.2	55.0	206.2
1.3	Withdrawal	79.7	79.7	0.0	79.7
1.4	Market Based Storage	17,210.1	9,591.0	8,198.3	17,789.2
1.5	Unutilized Transportation Costs	0.0	0.0	0.0	0.0
1.6	Other	2,198.1	2,198.1	604.7	2,802.8
1.	Total Storage	20,510.4	12,144.4	8,924.4	21,068.8
2.	Total Transportation	67,949.1	36,811.3	30,242.4	67,053.7
	Dehydration				
3.1	Demand	1,021.2	556.1	463.0	1,019.0
3.2	Commodity	209.8	209.8	0.0	209.8
3.	Total Dehydration	1,231.0	765.8	463.0	1,228.8
4.	Total Storage & Other Costs	89,690.5	49,721.6	39,629.8	89,351.4
	Fuel Costs				
5.1	Tecumseh	2,140.6	858.8	598.0	1,456.7
5.2	Union Storage	877.2	506.5	135.6	642.1
5.3	Union Transportation	6,900.6	6,155.1	0.0	6,155.1
5.	Total Fuel Costs	9,918.4	7,520.3	733.6	8,253.9
6.	Unutilized Transportation Costs	0.0	0.0	0.0	0.0
7	Total Storage & Transportation	99,608.9	57,241.9	40,363.3	97,605.3
8.	Storage and Transportation Costs Charged to Gas Cost to Operations				97,605.3

SUMMARY OF GAS COST TO OPERATIONS
YEAR ENDED DECEMBER 31, 2014

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	9,039,790.8	1,859,283.4	205.678	5.457
12.	Storage Fluctuation	(740,674.5)	(214,496.9)		
13.	Commodity Cost to Operations	8,299,116.3	1,644,786.5	198.188	
14.	Storage and Transportation Costs		97,605.3		
15.	Gas Cost to Operations	8,299,116.3	1,742,391.8	209.949	5.570
16.	T-Service Transportation Costs		71,827.5		
17.	Accounting Adjustments		1,300.0		
18.	2014 Gas Costs	8,299,116.3	1,815,519.3		

CME INTERROGATORY #12

INTERROGATORY

Reference: Exhibit D2, Tab 1, Schedule 1, pages 22 and 23

To what extent was EGD able to mitigate UDC costs in 2014? Please provide information which will demonstrate the total amount of secondary market assignment activity which took place in 2014 on upstream transportation systems on which EGD incurred UDC and indicate the approximate proportion of that secondary market activity in which EGD was involved.

RESPONSE

The updated 2014 Gas Supply plan identified a total of 66.1 PJ's of unutilized transportation capacity at a total cost of $104.3 million. The Company sought to record this amount in either the 2014 Design Day Criteria Transportation Deferral Account (2014 DDCTDA) or the 2014 Unabsorbed Demand Charges Deferral Account (2014 UDCDA). The settlement agreement reached between the Company and interested parties in EB-2012-0459 accepted these forecast amounts. The Settlement Agreement also described the efforts that the Company would undertake to mitigate potential UDC in 2014. Page 6 of the Settlement Agreement states:

> *…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.*

Also contained within the Settlement Agreement, Enbridge committed to provide a monthly report outlining, *inter alia*, the level of unutilized capacity, the associated cost of that capacity, the amount of capacity that was released into the market place and the associated revenue received from the release of that capacity. A copy of the aforementioned monthly report, as at the end of December 2014, has been attached for reference.

The Company's UDC mitigation efforts in 2014 are not the subject of the immediate application but may be relevant within the 2014 ESM proceeding when clearance of the 2014 DDCTDA and 2014 UDCDA is sought. The year-end balance in the 2014 DDCTDA and 2014 UDCDA totals $26.5 million. The Company will be seeking to recover this amount from ratepayers along with the disposition of the other 2014 deferral accounts within the 2014 ESM proceeding.

During 2014, the Company was able to utilize 45.9 PJ's of the originally forecasted unutilized capacity. The remainder, or 20.2 PJ's of capacity, was successfully released to the market by the Company. The Company received $5.3 million from releasing the excess long haul capacity into the marketplace. This was used to offset the cost of the unutilized capacity ($31.8 million) leaving a balance in the two deferral accounts totaling the $26.5 million mentioned above.

The Company is not aware of nor is it able to provide the total amount of contracted capacity that was made available to the secondary market by other entities and can only speak to the levels, as discussed above, that EGD itself made available.

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December 31, 2014

VIA RESS and COURIER

Ms Kirsten Walli
Board Secretary
Ontario Energy Board
2300 Yonge Street, Suite 2700
Toronto, Ontario, M4P 1E4

Dear Ms Walli:

Re: Enbridge Gas Distribution Inc. 2014 to 2018 Rate Application
Ontario Energy Board File No. EB-2012-0459

As per the Settlement Agreement in EB-2012-0459 (Exhibit N1, Tab 2, Schedule 1, p. 6 of 19) the Company committed to provide a report to the parties of the Settlement Agreement to allow for the ongoing monitoring of UDC impacts in 2014. Please see the attached report for November, 2014.

Please do not hesitate to contact me with any questions.

Yours Truly,

(Original Signed)

Andrew Mandyam
Director, Regulatory Affairs and Financial Performance

Attach.

cc: EB-2012-0459 Interested Parties

December 2014 Report

Demand	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual - Updated July	Actual August	Actual September	Actual October	Actual November	Estimate December	
PJ's	85.9	73.1	70.5	40.9	22.1	15.4	15.4	14.7	16.5	27.0	51.7	60.6	493.9

Forecasted Monetary Impacts by Delivery Area
$ millions

	January	February	March	April	May	June	July	August	September	October	November	December	
UDCDA													
- CDA	-	-	-	-	-	-	0.6	4.5	2.9	3.2	-	-	11.2
- EDA	-	-	-	-	-	-	0.3	2.0	1.3	1.4	-	-	5.0
Revenue From Unutilized Capacity Released	-	-	-	-	-	-	(0.2)	(0.9)	(0.6)	(1.0)	-	-	(2.7)
Net Impact on Deferral Account	-	-	-	-	-	-	0.7	5.5	3.6	3.7	-	-	13.6
DDCTDA													
- CDA	-	-	-	-	-	-	3.5	3.6	3.5	3.0	-	-	13.6
- EDA	-	-	-	-	-	-	0.5	0.5	0.5	0.4	-	-	1.9
Revenue From Unutilized Capacity Released	-	-	-	-	-	-	(0.8)	(0.6)	(0.6)	(0.7)	-	-	(2.6)
Net Impact on Deferral Account	-	-	-	-	-	-	3.2	3.5	3.4	2.7	-	-	12.9

Forecasted Monthly Unutilized Capacity by Delivery Area
PJ's -

	January	February	March	April	May	June	July	August	September	October	November	December	
UDCDA													
- CDA	-	-	-	-	-	-	0.4	2.8	1.9	2.1	-	-	7.2
- EDA	-	-	-	-	-	-	0.2	1.2	0.8	0.9	-	-	3.1
Unutilized Capacity Released	-	-	-	-	-	-	(0.6)	(4.1)	(2.7)	(3.0)	-	-	(10.2)
Net Unutilized Capacity	-	-	-	-	-	-	-	-	-	-	-	-	-
DDCTDA													
- CDA	-	-	-	-	-	-	2.2	2.3	2.3	1.9	-	-	8.7
- EDA	-	-	-	-	-	-	0.3	0.3	0.3	0.3	-	-	1.2
Unutilized Capacity Released	-	-	-	-	-	-	(2.5)	(2.6)	(2.6)	(2.2)	-	-	(9.9)
Net Unutilized Capacity	-	-	-	-	-	-	-	-	-	-	-	-	-
Total													
- CDA	-	-	-	-	-	-	2.6	5.2	4.1	4.0	-	-	15.9
- EDA	-	-	-	-	-	-	0.5	1.5	1.1	1.1	-	-	4.2
Unutilized Capacity Released	-						(3.1)	(6.7)	(5.2)	(5.1)	-		
Net Unutilized Capacity	-	-	-	-	-	-	-	-	-	-	-	-	20.1

Degree Days													
Central Region	813.0	724.1	669.3	352.3	127.4	12.6	4.9	9.3	70.0	230.7	474.2	550.0	4,037.8
Niagara Region	758.1	679.1	637.5	330.0	137.6	14.9	5.1	5.8	69.9	203.1	439.6	526.1	3,806.8
Eastern Region	895.2	775.3	751.1	381.2	124.0	14.9	10.4	22.0	115.3	260.9	507.7	725.7	4,583.7

Discretionary Requirement

	January	February	March	April	May	June	July	August	September	October	November	December	
PJ's	15.0	16.2	21.8	9.0	-	-	-	-	-	-	5.1	13.5	80.6

Month end Storage Capacity

% Fill	0.39	0.19	0.14	0.20	0.35	0.49	0.75	0.87	0.97	1.00	0.94	0.78

Month end Storage Capacity Taget

% Fill	0.47	0.24	0.06	0.07	0.20	0.36	0.56	0.75	0.92	1.00	0.95	0.78

CME INTERROGATORY #13

INTERROGATORY

Reference: Exhibit D2, Tab 1, Schedule 1, pages 22 and 23

Using EGD's estimate of the maximum UDC exposure its customers faced in 2014, please describe the activities in which EGD engaged to mitigate UDC and quantify the total value of those mitigation efforts in reducing UDC.

RESPONSE

Please see response to CME Interrogatory #12 at I.D2.EGDI.CME.12. As stated, details of EGD's actual UDC costs for 2014 as recorded within the 2014 DDCTDA and 2014 UDCDA , including the mitigation efforts undertaken, will be relevant within the 2014 ESM proceeding.

Witness: D. Small

CME INTERROGATORY #14

INTERROGATORY

Reference: Exhibit D2, Tab 1, Schedule 1, pages 22 and 23

What is EGD's estimate of the extent to which it will likely be able to mitigate the $130 M of UDC exposure if faces in 2015? Please include with that estimate the assumptions on which it is based.

RESPONSE

The extent of UDC mitigation will be determined by a variety of factors including but not limited to weather/demand and secondary market conditions. The full extent of UDC mitigation will not be known until the end of 2015.

The Company is currently forecasting to acquire 15.3 PJ's of Dawn Discretionary Supply throughout the June 2015 to October 2015 period. If the Company experiences budgeted demand in 2015 and requires this volume for purposes of injecting gas into storage then, as it did in 2014, the Company will utilize the unutilized FT capacity instead of acquiring gas at Dawn. Please see the response to Board Staff #8 for further details on the Company's UDC mitigation plans.

Included within the 2015 rate application (Ex. D1, Tab 2, Schedule 1, Appendix A) is a copy of the proposed UDC report the Company intends to update and file with the Board on a monthly basis. The forecasted UDC amount of $130 million was based upon the TCPL tolls in place prior to January 1, 2015. In response to Board Staff Interrogatory #8 at Exhibit I.D1.EGDI.STAFF.8, the Company provided an update to that schedule based upon the Settlement Tolls including the Abandonment Surcharge that are effective January 1, 2015. The updated UDC exposure would be $166.4 million. The Company has also updated its pre-filed evidence at Exhibit D1, Tab 2, Schedule 1, page 6, paragraph 15 and at Exhibit D2, Tab1, Schedule 1, page 23, paragraph 77 to reflect the change as well. However, as described above, this amount could be reduced by $30.4 million should the Company require 15.3 PJ's of supply next summer for the purposes of filling storage.

Witness: D. Small

CME INTERROGATORY #15

INTERROGATORY

Reference: Exhibit D, Tab 1, Schedule 2, page 3, question 6

Does the $9 M credit amount, which, according to the evidence, originated in 2009, include interest over the years 2009 to 2014? If not, then please recalculate the amount with interest included.

RESPONSE

No, the amount does not include interest. Enbridge proposes to refund the outstanding credit balance as at December 2014 via the Credit Final Bill Deferral Account ("CFBDA"). It is not appropriate to include interest on the balance that has accumulated since 2009. This is because the fluctuating credit balances resulted in an offset to the Company's total A/R outstanding during this period. Impacts within resulting total cash flow would have had the effect of reducing total interest expense with related impacts already having affected past utility earnings sharing results.

Witnesses: K. Lakatos-Hayward
D. McIlwraith

CME INTERROGATORY #16

INTERROGATORY

Reference: Exhibit D, Tab 1, Schedule 2, page 3, question 6

What were the credit balances related to this item in each of the years 2009 to 2014?

RESPONSE

As per the Company's original evidence, the full extent of the problem was not realized until October 2011. As such, detailed information on year-end balances for 2009 and 2010 are not available. Year-end balances from 2011 – 2014 were as follows:

2011 - $22.2 M
2012 - $22.1 M
2013 - $16.2 M
2014 - $7.1 M

Witnesses: K. Lakatos-Hayward
D. McIlwraith

CME INTERROGATORY #17

INTERROGATORY

Reference: Exhibit D, Tab 1, Schedule 2, page 3, question 6

Please describe the regulatory treatment ascribed to these credit balances over each of those years. In particular, did the credit balances contribute to earnings subject to sharing, or were the amounts credited in full to customers in some other fashion since they were not recorded in a deferral account in any of those years?

RESPONSE

The credit balances on their own did not contribute to earnings over this period as there was no impact on revenues. However, the credit balances did accumulate as an offset to Accounts Receivable (effectively lowering the A/R amounts). The impact of this would have been to reduce interest expense, which in turn would positively impact on the net earnings that were subject to earnings sharing.

Witnesses: K. Lakatos-Hayward
D. McIlwraith

CME INTERROGATORY #18

INTERROGATORY

Reference: Exhibit D, Tab 1, Schedule 2, page 3, question 6

Why did EGD wait 5 years before proposing deferral account treatment for this credit balance?

RESPONSE

The Company has always had the intention of returning these funds to customers and has been actively working to refund these credit balance accounts since 2011 when the extent of the problem became clear. The task of tracing customers through various means, both automated and manual, took significant time, effort and cost. After working on these accounts extensively and reducing the balance down to $7.0 MM currently, the Company will be, at the end of 2015, at a point where the probability of successfully locating the original account holders is quite low. Having exhausted all avenues to return these amounts to specific customers EGD has finally concluded that refunding these amounts to the relevant customer groups on an overall basis via deferral account treatment is the most appropriate course of action. To have done so earlier would have increased the total amount not returned to the appropriate account holders.

Witnesses: K. Lakatos-Hayward
D. McIlwraith

ENERGY PROBE INTERROGATORY #10

INTERROGATORY

Ref: Exhibit D2, Tab 1, Schedule 2

Please update the 2015 DSM related accounts shown on pages 21 and 22, if necessary, to reflect the Board's EB-2014-0134 Report of the Board - Demand Side Management Framework for Natural Gas Distributors (2015-2020).

RESPONSE

At this time, the Company does not believe any updates to the DSM related deferral account descriptions are needed as a result of the Board's EB-2014-0134 Report of the Board - Demand Side Management Framework for Natural Gas Distributors (2015-2020).

Witness: R. Small

BOARD STAFF INTERROGATORY #18

INTERROGATORY

Credit Final Bill Deferral Account (CFBDA)

Ref: ExD2/T1/S2/para 5

The proposed deferral account will track un-refunded credit amounts owing to customers with finalized accounts. Paragraph 5 describes the efforts at locating such 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."

a. In efforts to locate the customers, is this done in any priority sequence – for example, are the largest refund balances pursued first, followed by lower refund balances?

b. How is Enbridge proposing to allocate the balance in the CFBDA at the time of disposition?

RESPONSE

a) Yes, a priority sequence was established as the Company worked through the list of accounts with credit balances. Larger balances were prioritized over smaller balances as were accounts that were simpler to validate and link to a current account holder. As a result, accounts remaining with a credit balances are generally those with smaller balances and/or account holders where manual efforts to find new contact information have failed.

b) Though the Company is not proposing an allocation methodology in this proceeding, it is anticipated that the Company will propose to allocate the amount recorded in the CFBDA directly to the rate class from which the credit balance originates (referred to as "Direct Allocation" in the Company's Clearance of Deferral and Variance Account proceedings).

Witnesses: K. Lakatos-Hayward
D. McIlwraith

VECC INTERROGATORY #13

INTERROGATORY

Reference: D2/T1/S2 Credit Final Bill Deferral Account

a) Please confirm that the CFBDA is a new account. Were any amounts recorded with respect to the final bill issue prior to 2015? If so in which account were these amounts recorded?
b) Please provide the year-end balances that were recorded between 2009 and 2014 for the credit bill issue (please show the year end customer debit amounts separately from customer credits).
c) At D2/T1/S2/pg.2 Enbridge describes steps it has taken to resolve this issue(s). Does the issue continue and if yes, please explain why?
d) What are the annual costs incurred by Enbridge to track these errors and attempt to resolve final bill issues related to this problem?
e) Enbridge states that there is $9 million of 2 year aged accounts where "[A*]t this point, unlikely that the Company will be able to return the amounts owed to these customers*." What is the proposal for this $9 million?

RESPONSE

a) Yes, the CFBDA is a new account. Any amounts recorded on this issue would have been reflected in the Company's Accounts Receivables balances.

b) As per the Company's original evidence, the full extent of the problem was not realized until October 2011. As such, detailed information on year-end balances for 2009 and 2010 are not available. Year-end balances from 2011 – 2014 were as follows:

   2011 - $22.2 M
   2012 - $22.1 M
   2013 - $16.2 M
   2014 - $7.1 M

   Customer debit amounts would include the Company's ongoing A/R balances which reflect current billed amounts plus arrears. These debit amounts fluctuate daily and have little relation to the issue described.

Witnesses: K. Lakatos-Hayward
D. McIlwraith

c) The system and process related issues that caused the issue originally have been addressed. There are occasional cases where finalized accounts result in an overpayment but these accounts are now actively worked and resolved as soon as possible. As a result, the issue has been resolved.

d) At the peak in 2012/2013, the Company incurred costs of approximately $1.1 M annually to manually work and resolve these account balances. The majority of these costs were for Customer Service Representatives (CSRs) from Accenture to review and process refunds owed to customers. This involved as many as 40 CSRs assigned to work on these accounts.

e) Our proposal is based on the fact that there are amounts that have been worked in many different ways where we are now confident we cannot properly locate the original customer to return the payment. We are proposing a deferral account so that these credit balances are returned to the benefit of all customers, but allowing the Company to recover future refunds should our continued efforts to locate these customers eventually succeed.

Witnesses: K. Lakatos-Hayward
D. McIlwraith