BOARD STAFF INTERROGATORY #1

INTERROGATORY

Ref: A1/T3/S1/para5

Please summarize what changes, if any, were made to the cost allocation and rate design models to create 2017 rates. Please briefly identify any departures in the models since the beginning of the Custom IR.

RESPONSE

As outlined in Exhibit G1, Tab 1, Schedule 1, page 1, paragraph 1, the Company is proposing to maintain its cost allocation methodology approved in EB-2012-0459 (2014 to 2018 Custom IR Plan) for the 2017 Test Year. The Company is also proposing to maintain its existing rate design methodology for the derivation of the 2017 proposed rates.

Dawn Transportation Service ("DTS") is forecast to commence in November 2017 as a result of the Dawn Access Settlement Agreement (EB-2014-0323). A description of the cost allocation methodology relating to DTS is outlined at Exhibit G1, Tab 1, Schedule 1, page 4, paragraphs 12 to 19. The rate design evidence describing the DTS rate offering can be found at Exhibit H1, Tab 1, Schedule 1, page 8.

The Company has modified the Rate 332 (Parkway to Albion King's North Transportation Service) rate schedule as approved in EB-2016-0028. The Company has included a Monthly Contract Demand Charge which is derived based on the Daily Contract Demand Charge. The rate design evidence describing this change can be found at Exhibit H1, Tab 1, Schedule 1, page 7.

Witnesses: J. Collier
A. Kacicnik

BOARD STAFF INTERROGATORY #2

INTERROGATORY

Ref: A1/T3/S1/para14

Please indicate if the “renewed” deferral and variance accounts being requested for 2017 are precisely the same accounts as approved by the OEB in 2016 and prior years. If not, please provide a track changes (or black-lined) version showing the changes.

RESPONSE

The renewed accounts refer to the 2017 Greater Toronto Area Incremental Transmission Capital Revenue Requirement Deferral Account (“GTAITCRRDA”), the 2017 Customer Care Services Procurement Deferral Account (“CCSPDA”), and the 2017 Rate 332 Deferral Account (“R332DA”). The differences between the 2016 and 2017 accounts are described below.

The purpose of the 2017 GTAITCRRDA, to record for recovery from transportation service customers the revenue requirement related to an incremental $55 million of forecast capital costs which resulted from the upsizing Segment A of the GTA project to an NPS 42 pipeline from an NPS 36 pipeline, in the event that at the time Segment A is put into service there are no Rate 332 transportation customer(s) or no ability for Rate 332 transportation customers to utilize Segment A, remains the same as the 2016 GTAITCRRDA. The only exception being that it would record the 2017 revenue requirement as compared to the 2016 revenue requirement.

The purpose of the 2017 CCSPDA, to capture the costs associated with benchmarking, tendering, and potential transition of customer care services to a new service provider, with a cumulative $5 million cap, remains the same as the 2016 CCSPDA. The change with the renewed 2017 account is with regards to the time period for which the account will be in place. The original account was approved for the 2014 through 2016 time period, while the renewed 2017 account is proposed for the 2017 through 2019 time period. The time period change results from the extension of the customer care outsourcing contract with Accenture through 2019 (which occurred in 2014), which delayed the potential incurrence of costs associated with benchmarking, tendering, and potential transition of customer care services to a new service provider.

The purpose of the 2017 R332DA remains the same as the 2016 R332DA, to ensure that the Company’s bundled customers only pay for the revenue requirement on the transportation component of Segment A (of the GTA project), net of the revenue requirement on the incremental $55 million in upsizing costs, where Rate 332 transportation service is not available. The difference between 2016 and 2017 is the assumption as to whether Rate 332 transportation service would be able to be offered, which dictates how the costs of the transportation component of Segment A are allocated for recovery, which in turn dictates when the R332DA would be utilized. In the 2016 rate application, the assumption was that Rate 332 transportation service would not be able to be offered during 2016. As a result, bundled customers were allocated the costs of the transportation component of Segment A, net of the revenue requirement on the incremental $55 million in upsizing costs (which was to be recovered through the 2016 GTAITCRRDA). The 2016 R332DA would therefore be utilized should Rate 332 transportation service be offered at any point during 2016, to refund to bundled customers Rate 332 billings received, net of any reduction in the amount forecast to be recovered through the 2016 GTAITCRRDA. In the 2017 rate application, the assumption is that Rate 332 transportation service will be able to be offered for all of 2017. As a result, bundled customers are not allocated costs related to the transportation component of Segment A. The 2017 R332DA would therefore be utilized should Rate 332 transportation service not be able to be offered for a portion or all of 2017, to collect from bundled customers forecast costs related to the transportation component of segment A, net of the revenue requirement on the incremental $55 million in upsizing costs, that would be recorded for recovery through the 2017 GTAITCRRDA.

BOARD STAFF INTERROGATORY #3

INTERROGATORY

Ref: A1/T3/S1/page 1 of 2/ Appendix B – Allowed Revenue Sufficiency / (Deficiency) 2017 Test Year Schedule

Please provide a variance analysis with explanations, in the same level of detail as the referenced schedule, showing 2016 OEB-approved revenues vs. proposed 2017 revenues.

RESPONSE

Attachment 1 to this response provides a comparison between each of the components of 2017 Updated Forecast allowed revenues (as reflected in the updated evidence filed November 8, 2016), revenues at existing rates, and resultant deficiency, relative to the 2016 Approved values, and identifies the main drivers for the variances.

Witness: R. Small

ALLOWED REVENUE AND SUFFICIENCY/(DEFICIENCY)

Line No.		Col. 1 2017 Total Updated Forecast Allowed Revenue ($Millions)	Col. 2 EB-2015-0114 2016 Allowed Revenue ($Millions)	Col. 3 Variance ($Millions)	Col. 4 Note
	Cost of capital				
1.	Rate base	6,024.1	5,806.9	217.2	a)
2.	Required rate of return	6.21	6.40	(0.20)	b)
3.		374.0	371.9	2.1	c)
	Cost of service				
4.	Gas costs	1,603.1	1,764.8	(161.7)	d)
5.	Operation and maintenance	459.9	456.6	3.3	e)
6.	Depreciation and amortization	297.7	288.9	8.8	f)
7.	Fixed financing costs	1.9	1.9	-	
8.	Municipal and other taxes	47.9	45.5	2.4	g)
9.		2,410.5	2,557.7	(147.2)	
	Miscellaneous operating and non-operating revenue				
10.	Other operating revenue	(42.7)	(42.7)	-	
11.	Interest and property rental	-	-	-	
12.	Other income	(0.1)	(0.1)	-	
13.		(42.8)	(42.8)	-	
	Income taxes on earnings				
14.	Excluding tax shield	54.7	70.8	(16.1)	
15.	Tax shield provided by interest expense	(48.1)	(47.2)	(0.9)	
16.		6.6	23.6	(17.0)	h)
	Taxes on sufficiency / (deficiency)				
17.	Gross sufficiency / (deficiency)	(29.4)	-	(29.4)	
18.	Net sufficiency / (deficiency)	(21.6)	-	(21.6)	
19.		7.8	-	7.8	h)
20.	**Sub-total revenue requirement**	2,756.1	2,910.4	(154.3)	
21.	Customer Care Rate Smoothing V/A Adjustment	2.8	0.8	2.0	i)
22.	**Allowed revenue**	2,758.9	2,911.2	(152.3)	
	Revenue at existing Rates				
23.	Gas sales	2,436.9	2,624.8	(187.9)	
24.	Transportation service	281.7	279.7	2.0	
25.	Transmission, compression and storage	6.7	6.7	-	
26.	Rounding adjustment	-	-	-	
27.	Revenue at existing rates	2,725.3	2,911.2	(185.9)	j)
28.	**Gross revenue sufficiency / (deficiency)**	(33.6)	-	(33.6)	

Witness: R. Small

2017 UPDATED FORECAST VERSUS 2016 APPROVED VARIANCE EXPLANATIONS

Note: Explanation

a) Rate Base

As seen below, the increase in 2017 updated forecast ratebase is due to the increase in forecast net property plant and equipment that was reviewed and approved within Enbridge's CIR proceeding EB-2012-0459, reflecting an additional year of core capital spending. The property, plant, and equipment increase was partially offset by reductions in gas in storage and working cash allowance which were updated in accordance with CIR plan parameters, and reflect an updated volume forecast, gas supply plan, PGVA reference price, and O&M inputs.

	2017 Forecast	2016 Approved	Variance	
Net property, plant and equip.	5,695.9	5,443.2	252.7	Reviewed and approved in EB-2012-0459
A/R rebillable projects	1.4	1.4	-	Reviewed and approved in EB-2012-0459
Materials and supplies	34.6	34.6	-	Reviewed and approved in EB-2012-0459
Mortgages receivable	-	-	-	Reviewed and approved in EB-2012-0459
Customer security deposits	(64.6)	(64.6)	-	Reviewed and approved in EB-2012-0459
Prepaid expenses	1.0	1.0	-	Reviewed and approved in EB-2012-0459
Gas in storage	356.6	391.1	(34.5)	Updated per CIR plan parameters
Working cash allowance	(0.8)	0.2	(1.0)	Updated per CIR plan parameters
Total working capital	328.2	363.7	(35.5)	
Total rate base	6,024.1	5,806.9	217.2	

b) Required rate of return

The reduction in the 2017 updated forecast required rate of return reflects the impact of a reduction in the forecast ROE, 8.78% in 2017 versus 9.19% in 2016 Approved, and a reduction in the forecast weighted average cost of debt rate, which reflects updated actual and forecast debt issuances and cost rates. ROE and cost of debt forecast updates are performed in accordance with CIR plan parameters.

c) Cost of capital

The increase in the 2017 updated forecast cost of capital results from financing a higher rate base (discussed in a) above), partially offset by a lower required rate of return (discussed in b) above).

d) Gas costs

The decrease in 2017 updated forecast gas costs is primarily due to a lower PGVA reference price, partially offset by an increase in forecast volumes, higher storage and transportation costs, and higher T-Service transportation costs resulting from higher TCPL tolls. The updated forecast 2017 gas costs reflect an adjusted July 2016 PGVA reference price of $166.901, while 2016 approved gas costs reflect an adjusted July 2015 PGVA reference price of $196.253. Gas costs were updated in accordance with CIR plan parameters. Corresponding updates for price and volumetric impacts are also reflected in updated forecast revenue at existing rates.

e) Operation and maintenance

The increase in 2017 updated forecast O&M is detailed below, but is primarily driven by a higher forecast DSM budget, which has been updated in accordance with CIR plan parameters and reflects the approved budget included within Enbridge's DSM Multi-Year Plan proceeding EB-2015-0049. Customer Care and CIS costs have been updated in accordance with CIR plan parameters to reflect the EB-2011-0226 settlement agreement, which requires annual updates for the forecast number of customers and the current year's approved cost per customer. Pension and OPEB costs have been updated to reflect current forecast costs provided by Mercer, as per CIR plan parameters.

	2017 Forecast	2016 Approved	Variance	
Customer Care / CIS	102.5	99.3	3.2	Updated per CIR plan parameters
DSM	62.9	56.4	6.6	Updated per CIR plan parameters
Pension and OPEB	24.7	34.6	(9.8)	Updated per CIR plan parameters
RCAM	34.8	33.8	1.0	Reviewed and approved in EB-2012-0459
Other O&M	234.9	232.6	2.3	Reviewed and approved in EB-2012-0459
Total O&M	459.9	456.6	3.3	

f) Depreciation and amortization

The increase in 2017 updated forecast depreciation and amortization was reviewed and approved within Enbridge's CIR proceeding EB-2012-0459, and reflects the impact of growth in forecast gross property, plant, and equipment.

g) Municipal and other taxes

The increase in 2017 updated forecast municipal and other taxes was reviewed and approved within Enbridge's CIR proceeding EB-2012-0459, and reflects the impact of forecast capital growth an inflation.

h) Income taxes on earnings and deficiency

The decrease in 2017 updated forecast income taxes is primarily attributable to a higher forecast income tax deduction for cash based pension and OPEB contributions, which was updated in conjunction with the updated forecast accrual based pension and OPEB costs.

i) Customer Care Rate Smoothing V/A Adjustment

The Customer Care Rate Smoothing V/A Adjustment has been updated, similar to Customer Care & CIS O&M costs, to reflect the impact of the EB-2011-0226 settlement agreement which requires annual updates for the forecast number of customers, as well as the current year's approved cost per customer and normalized cost per customer.

j) Revenue at existing rates

The decrease in 2017 updated forecast revenue at existing rates is due primarily to a lower gas commodity (PGVA) reference price embedded within rates (discussed in d) above), partially offset by the updated 2017 volumetric forecast.

BOARD STAFF INTERROGATORY #4

INTERROGATORY

Ref: A1/T3/S1/page 1 of 2/ Appendix B – Allowed Revenue Sufficiency / (Deficiency) 2017 Test Year Schedule

Please explain the details underpinning what appears to be a $23.5 million income tax deficiency (credit) adjustment shown in column 2; “2017 Required Updates” at line 19. Please relate the $23.5 million amount to the detailed tax calculation schedule at D1/T6/S2 which shows an increase in taxes of $3.8 million (line 32 column 2).

RESPONSE

The $23.5 million credit shown at Line 19, Column 2, of Exhibit A1, Tab 3, Schedule 1, Appendix B reflects a reduction in income taxes required in relation to the lower net deficiency amount (Excluding CIS and Customer Care impacts) requested within this proceeding as part of the 2017 Updated Forecast Allowed Revenue, as compared to the income taxes required on the net deficiency that was reflected in the Custom IR (EB-2012-0459) 2017 Placeholder Allowed Revenue. The primary driver for the reduction in the net deficiency included within the 2017 Updated Forecast Allowed Revenue, versus the 2017 Placeholder Allowed Revenue, is the rates which underpin revenues at existing rates within each proceeding. The 2017 Updated Forecast revenue at existing rates was determined utilizing 2016 approved rates (EB-2015-0114), while the 2017 Placeholder revenue at existing rates was determined utilizing 2013 approved rates. As a result, the 2017 Updated Forecast deficiency reflects the variance between updated forecast 2017 allowed revenues and updated forecast 2017 revenues based on 2016 approved rates, while the 2017 Placeholder deficiency reflected the cumulative variance between forecast 2017 allowed revenues and forecast 2017 revenues based on 2013 approved rates (i.e., it did not reflect the rate changes that occurred as a result of approved 2014, 2015, and 2016 approved rates).

The $3.8 million increase in income taxes shown at Line 32, Column 2, of Exhibit D1, Tab 6, Schedule 2, reflects higher income taxes on earnings (taxable income) (Excluding CIS and Customer Care impacts) resulting from the 2017 Updated Forecast revenues and costs included within this proceeding, as compared to the 2017 Placeholder amounts included within the Custom IR proceeding. The calculation of income tax on earnings, shown in Exhibit D1, Tab 6, Schedule 2, does not include the income taxes required in relation to net deficiency amounts (i.e., the gross-up of net deficiency amounts). Corresponding with what was mentioned above, a primary driver for the higher income tax on earnings, reflected in the 2017 Updated Forecast, is the fact that the updated forecast revenues and income before taxes reflect the impact of 2016 approved rates, while the 2017 placeholder revenues and income before taxes reflected 2013 approved rates. The increase in 2017 Updated Forecast income taxes on earnings also reflects the net impact of all other updates (i.e., volumes, DSM costs, pension and OPEB costs, cost of capital, etc.), including tax add and deduct impacts, required as part of Enbridge's approved Custom IR plan. The increase in income taxes on earnings, shown at Line 32, Column 2, of Exhibit D1, Tab 6, Schedule 2, is reflected in Exhibit A1, Tab 3, Schedule 1, Appendix B, at Row 19, Column 2.

Exhibit A1, Tab 3, Schedule 1, Appendix B is a summary schedule which shows total allowed revenue and deficiency amounts (Excluding CIS and Customer Care amounts plus CIS and Customer Care amounts). For a clearer breakdown of 2017 Placeholder and Updated Forecast allowed revenue and deficiency amounts (including income taxes on earnings and incomes taxes on deficiency), which segregates Excluding CIS and Customer Care amounts from CIS and Customer Care amounts, please refer to Exhibit F1, Tab 2, Schedule 1.

BOMA INTERROGATORY #1

INTERROGATORY

Ref: Exhibit A1, Tab 2, Schedule 1, Page 3

Please explain why the cap and trade rates need to be introduced as part of the January 1, 2017 QRAM.

RESPONSE

The Board's EB-2015-0363, Regulatory Framework for Natural Gas Utilities Cap and Trade Activities issued September 26, 2016 states the following at page 38.

> The OEB expects the Utilities to file applications with their initial Compliance Plans by November 15, 2016 in order for the OEB to set interim rates to allow for the recovery of Cap and Trade compliance costs. By ensuring rates are in place as January 1, 2017 the OEB expects to avoid any significant variances in the annual rates once it completes its assessment of the Compliance Plans.

Witnesses: K. Culbert
A. Kacicnik

BOMA INTERROGATORY #2

INTERROGATORY

Ref: General

Please confirm that the Board's recently adjusted ROE will be used in determining 2017 rates.

RESPONSE

Confirmed. The Company will use the ROE of 8.78% as issued by the Board in its "Cost of Capital Parameters Updates for 2017 Cost of Service and Custom Incentive Rate-setting Applications," issued October 27, 2016, in the determination of final 2017 rates. Updated evidence reflecting an ROE of 8.78% was filed on Tuesday, November 8, 2016.

Witness: R. Small

BOMA INTERROGATORY #3

INTERROGATORY

Ref: Application, Page 1

Please explain the 2017 "Placeholder" concept. Please illustrate with reference to the EB-2012-0459 Decision. See also IR #23.

RESPONSE

The manner in which the Board approved certain elements and amounts for 2015 through 2018 within the EB-2012-0459 proceeding, and the manner in which other elements and amounts were approved as placeholders to be updated in subsequent rate applications prior to each of these fiscal years is explained in the EB-2012-0459 Decision with Reasons, at pages 83 and 84. This is also outlined and explained in the evidence in this proceeding, within Exhibit A1, Tab 3, Schedule 1 along with Appendices A and B to that exhibit.

Witness: K. Culbert

ENERGY PROBE INTERROGATORY #1

INTERROGATORY

References: A1, Tab 2, Schedule 1; Exhibit C2, Tab 1, Schedule 3, Page 22

Preamble: 7. Enbridge's final rates for 2017 include its Cap and Trade Unit Rates, as required by the Board's July 28, 2016 "Early Determination Regarding Billing of Cap and Trade Related Costs and Customer Outreach" (the "Early Determination") in the EB-2015-0363 proceeding. Enbridge is not seeking approval of the Cap and Trade Unit Rates in this Rate Adjustment Application. Instead, the Cap and Trade Unit Rates- as well as necessary additional Variance or Deferral Accounts- will be presented for approval within Enbridge's 2017 Compliance Plan, which is to be filed by November 15, 2016. Enbridge requests that approval of the 2017 Cap and Trade Unit Rates be granted in sufficient time to allow for implementation in conjunction with the January 1, 2017 QRAM Application.

a) Please provide a copy of the Board Direction to EGD regarding Customer GHG Commitments.

b) What is the status regarding EGD's Customer GHG Charges/Billing implementation?

c) Please provide an illustration of the charges for Rates 1 and 6 using EGD's "best guess". List relevant assumptions.

d) What is/are EGD's expectation(s) regarding implementation/timing of customer GHG charges?

e) Please provide a copy of EGD's GHG Compliance Plan in this proceeding as soon as available.

f) Please provide EGD's opinion on whether GHG customer cost changes are a Z factor affecting both revenues and operating costs.

Witnesses: K. Culbert
A. Kacicnik

RESPONSE

a) The direction to Enbridge regarding the Regulatory Framework for Natural Gas Utilities Cap and Trade Activities is found in the Board's Early Determination letter dated July 28, 2016 and in the Report of the Board dated September 26, 2016, both within the EB-2015-0363 docket on the Board's website. In the Report of the Board and associated cover letter, Enbridge was directed to a file Cap and Trade Compliance Application by November 15, 2016, including a request for interim and final Cap and Trade tariffs. This means that the review and approval of Cap and Trade tariffs will occur within a separate proceeding, distinct from this rate adjustment application.

b-f) In the Appendix to the Board's September 26, 2016 Report on the Framework, the Board indicated all the items and information that must be filed in the Compliance Plan application. Enbridge's application will include all required items.

Witnesses: K. Culbert
A. Kacicnik

BOARD STAFF INTERROGATORY #5

INTERROGATORY

Ref: B1/T1/S1/para2

Please provide a variance analysis showing both the price variance and volume variance components of line 9 “Gas in storage” Col 1 vs Col 3.

RESPONSE

There are four elements that make up the balance in Gas in Storage – System supply volumes valued at the current PGVA Reference Price, the transportation cost associated with the Western T-Service volumes in storage, the associated fuel cost to inject/withdraw gas from storage and move gas easterly/westerly on Union’s system and the accumulation of storage and transmission demand charges that are charged to gas costs over the winter period.

The table below provides a breakdown of the average of average amounts associated with each of these four components for the 2016 Board approved budget and the 2017 forecast. Further information about the variances seen in this table can be found in the response to FRPO Interrogatory #1 at Exhibit I.B1.EGDI.FRPO.1.

Average of Average Storage Balances

	2016 Board Approved Budget			2017 Forecast		
	10*6 m*3	$/10*3 m*3	$ million's	10*6 m*3	$/10*3 m*3	$ million's
System Supply Volumes	1,595.8	196.253	313.2	1,753.8	166.901	292.7
Western T Volumes	507.3	75.303	38.2	228.9	74.792	17.1
Storage and Transmission Fuel Cost			7.6			9.0
Demand & In Charges			32.2			37.8
			391.1			356.6

Witness: D. Small

BOMA INTERROGATORY #4

INTERROGATORY

Ref: Exhibit B1, Tab 1, Schedule 3

Why is such a large volume/value of gas in storage in forecast for April 2012?

RESPONSE

The higher forecasted storage balance at the end of April 2017 can be attributed to the change in gas supply planning strategy adopted starting with the Board-approved 2015 forecast (EB-2014-0276), to carry higher storage balances later into the winter season. As a consequence, storage balances remain higher at the end of the withdrawal cycle.

Witness: D. Small

ENERGY PROBE INTERROGATORY #2

INTERROGATORY

References: B1, Tab1 Schedule 1; E8-2015-0114 Exhibit 1.B1.EGDI.APPr0.4 part b

	Prefiled Evidence EB-2012-0459 Exhibits 82-1-1- Page 4and M1-1-1 (in Millions)						Status at October 2015 (In Millions)					
	2013 Board Approved Budget	2014 Forecast	2015 Forecast	2016 Forecast	Total		Pre 2014	2014 Actual	2015 Forecast	2016 Forecast	2017 Forecast	Total
GTA Reinforcement	25.4	226.3	434.8		686.5		*24.5*	173.5	619.5	100.7	13.7	931.9
WAMS	0.5	36.3	25.7	8.1	70.6			19.9	29.6	28.6		78.1
Total Major Projects	25.9	262.6	460.5	8.1	757.1		24.5	193.4	649.1	129.3	13.7	1,010.0

a) Please update the major Capital Project Status provided in the above 2016 interrogatory response.

b) What is the current expected in-service date for TransCanada's King's North Project?

c) If there are any in-service delays, please list and describe EGDs contingency plans.

RESPONSE

a) Status of the GTA and Other Major Projects

There are two major projects included in rate base for 2016.

GTA Project

All pipelines and facilities associated with the GTA Project, except Ashtonbee and Buttonville Stations, were energized as of March 31, 2016. As described in the Interim Monitoring Report, filed with the Board on September 30, 2016, final clean-up and restoration occurred in the spring of 2016 and was completed by the end of June. Tree and shrub planting was deferred until fall, due to the extremely dry summer, but was completed in October. Pipeline and facilities construction and restoration are now complete. At the present time, work is continuing on project close-out activities.

As per the update to the Board on October 26, 2016, the current estimated in-service date for Ashtonbee Station is January 2017. The next steps for Buttonville Station are under review.

Witnesses: S. Fallis
D. Small
R. Small

WAMS

The WAMS project has completed the construct phase. The construct phase was subdivided into five build group packages, with the last build group completed end of January 2016. The program has subsequently conducted integration testing, user acceptance testing, business readiness, training development and training delivery. The project go-live date was completed on October 11, 2016.

Original Budget and Current Forecasted Costs

	Prefiled evidence EB-2012-0459 Exhibits B2-1-1 - Page 4 and M1-1-1 (in Millions)					Status at October 2016 (in Millions)					
	2013 Board Approved Budget	2014 Forecast	2015 Forecast	2016 Forecast	Total	Pre 2014	2014 Actual	2015 Actual	2016 Forecast	2017 Forecast	Total
GTA	25.4	226.3	434.8		686.5	24.5	173.5	551.1	124.0	27.6	900.7
WAMS	0.5	36.3	25.7	8.1	70.6	0.0	19.6	27.5	34.0	3.2	84.4
Total Major Projects	**25.9**	**262.6**	**460.5**	**8.1**	**757.1**	**24.5**	**193.1**	**578.6**	**158.0**	**30.9**	**985.1**

b) Please see response to Board Staff interrogatory #14 at Exhibit I.D1.EGDI.STAFF.14.

c) Please see response to Board Staff interrogatory #14 at Exhibit I.D1.EGDI.STAFF.14.

Witnesses: S. Fallis
D. Small
R. Small

ENERGY PROBE INTERROGATORY #3

INTERROGATORY

Reference: Exhibit B1, Tab 1, Schedule 1, Page 3

Preamble: The 2017 forecast gas in storage value has been updated to reflect changes resulting from the 2017 volumes re-forecast (inclusive of the allocation of LUF to Unregulated Storage), and re-determined 2017 gas supply plan. The updated gas in storage value also reflects July 1, 2016 QRAM prices, whereas the 2017 placeholder gas in storage value reflected April 1, 2013 QRAM prices. These updates have resulted in an increase to gas in storage of $80.3 million.

a) Please confirm/provide the specific respective QRAM prices from April 1, 2013 ($183.599/$10^3$ m^3) and July 1, 2016.

b) Please confirm/demonstrate how those prices equate to the increase in the value of gas in storage, relative to the 2017 placeholder.

c) Other than price, what other factors are affecting value of gas in storage, such as higher inventory levels and changes in base gas pressure? Please delineate price from these other factors.

d) Please provide EGD's protocol for updating gas in storage for determination of WC Allowance, including which QRAM is appropriate for January 1 rates.

RESPONSE

a), b) and c)

The primary driver for the $80.3 million increase in gas in storage can be attributed to the difference in volume and price.

The 2017 Rate Base Placeholder for Gas in Storage assumed an adjusted April 1, 2013 QRAM Reference Price of $183.599 /$10^3m^3$ and an average of averages storage balance of 1,179.4 10^6m^3. The 2017 Forecast as filed in EB-2016-0215 is based upon an adjusted July 1, 2016 QRAM Reference of $166.901/$10^3m^3$ and an average of averages balance of 1,753.8 10^6m^3.

Witnesses: D. Small
R. Small

The higher volume forecasted in 2017 is a result in a change in Enbridge's gas supply planning process to maintain higher gas in storage balances until the end of February and contributes to an increase of $105.5 million in the gas in storage rate base amount. This change in gas supply planning was first introduced as part of the 2015 Rate Adjustment, EB-2014-0276 application. The lower reference price contributes to a $29.3 million reduction in gas in storage. There is no impact because of changes in base pressure gas. The table below provides a breakdown of the gas in storage balances

Average of Average Storage Balances

	2017 Placeholder			2017 Forecast		
	10*6 m*3	$/10*3 m*3	$ million's	10*6 m*3	$/10*3 m*3	$ million's
System Supply Volumes	1,179.4	183.599	216.5	1,753.8	166.901	292.7
Western T Volumes	326.7	84.535	27.6	228.9	74.792	17.1
Storage and Transmission Fuel Cost			5.1			9.0
Demand & In Charges			26.9			37.8
			276.2			356.6

d) In accordance with Appendix E of the EB-2012-0459 Final Rate Order, within each of the 2015 through 2018 rate applications, the gas in storage component of rate base working capital is to be reforecast annually and reflected in the determination of updated revenue requirements, as a result of the annual volumes reforecast and corresponding gas supply plan redetermination. Within the rate application, the gas in storage value will be determined using the most recently approved PGVA reference price included within approved rates (adjusted to reflect the test year's reforecast supply mix). However, as part of the January 1st QRAM application, and each of the subsequent April 1st, July 1st, and October 1st applications, the value of gas in storage and corresponding revenue requirement impacts will be revised/superseded to reflect the updated PGVA reference price approved as part of those applications.

Witnesses: D. Small
R. Small

FRPO INTERROGATORY #1

INTERROGATORY

REF: Exhibit B1, Tab 1, Schedule 2

Preamble: In addition to Board Staff's inquiry regarding the price and volume aspects of the Gas in Storage variance.

Please provide an explanation of the specific drivers that lead to the variances.

RESPONSE

The forecasted gas in storage balances shown in response to Board Staff Interrogatory #5 at Exhibit I.B1.EGDI.STAFF.5, are based upon actual volumetric balances at the time the forecast is being prepared and incorporate a forecast of deliveries and consumption for the forecast period. To the extent there is difference from one year to the next pertaining to forecast sales and Direct Purchase customers then that will influence changes in forecasted gas in storage balances. Migration between sales service and T-Service is beyond the Company's control.

As seen in the response to Board Staff Interrogatory #5 at Exhibit I.B1.EGDI.STAFF.5, the different gas prices that applied in 2016 versus 2017 contribute to the budget variance.

Additionally, as part of the forecasting process, the Company includes the impact of any changes in transportation contracting to move gas from Dawn to Parkway. The costs associated with incremental Union transmission capacity that coincided with the GTA project become fully effective in 2017 and contribute to a majority of the increase in Demand and In Charges in 2017 versus 2016. Similarly because the Company has contracted for additional Union M12 capacity there is an increase in forecasted fuel cost to move that volume in 2017 as well.

Witnesses: D. Small
R. Small

FRPO INTERROGATORY #2

INTERROGATORY

REF: Exhibit B1, Tab 1, Schedule 2

Preamble: In addition to Board Staff's inquiry regarding the price and volume aspects of the Gas in Storage variance.

Please identify for each of the drivers which are inside of management control.

RESPONSE

Please refer to the response to FRPO #1 at Exhibit I.B1.EGDI.FRPO.1 that sets out the drivers of the variance in Gas Storage volumes and cost.

The first two elements of gas in storage described in response to Exhibit I.B1.EGDI.FRPO.1 pertain to the volumetric forecast of sales service and Direct Purchase customers. As gas in storage volume is reforecast each year as part of the gas supply planning process which is based upon an overall volumetric forecast using updated information such items as changes in customer additions, changes in the number of customers in each service type and changes in degree days, this means that any variance year over year is outside management control. The dollar value of that gas in storage balance is dependent upon an updated reference price which is outside of management's control as well.

The third element described in Exhibit I.B1.EGDI.FRPO.1 is Demand & In Charges which pertain to the monthly demand charges payable for storage and transmission service and any costs associated with injection charges. While demand charges are based upon contract levels entered into by the Company, the amount paid for those services are outside management control. Injection charges are dependent of amount of volume injected into storage which will be influenced by the volume forecast described above.

The final element is related to the fuel cost forecast related to storage injection/withdrawal and moving gas on Union's transmission system. The fuel volume required is a function of the volumetric forecast which is costed at an updated reference price which as described above is outside management control.

Witnesses: D. Small
R. Small

VECC INTERROGATORY #1

INTERROGATORY

Reference: B1/T1/S1

a) Please provide a breakdown of the $80.3 million in incremental gas costs to the constituent into the volume, price and allocation constituent components.

RESPONSE

Please see response to Energy Probe #3 at Exhibit I.B1.EGDI.EP.3.

Witnesses: D. Small
R. Small

BOARD STAFF INTERROGATORY #6

INTERROGATORY

Ref: C1/T2/S1/para6

Please explain how the cap and trade volumetric consumption impacts will be specifically isolated in the Average Use True-up account for rate 1 and rate 6.

RESPONSE

The Company has not indicated that it will explicitly isolate the impact of cap and trade on average use for rate 1 and rate 6. As the volumetric forecast for 2017 does not include any impacts of cap and trade on forecast average uses, or overall volumes for that matter, any decline in actual average use, all else equal, attributable to the cap and trade program will be captured as part of the difference between actual normalized average use and forecast normalized average use. This difference or variance will thus be captured, but not separately identified, in the AUTUVA.

Witness: M. Suarez

BOARD STAFF INTERROGATORY #7

INTERROGATORY

Ref: C1/T2/S1/para24

Please explain in detail the main drivers of the increase in volume showing in 2017 vs 2016 in the Contract market.

RESPONSE

Exhibit C3, Tab 2, Schedule 3, page 3 provides an itemization of the main drivers by rate class and service. The explanation below will focus on total volumes shown at line 4, for both Contract Sales and T-Service.

The increase in Contract Market volumes of 78.4 10^6m^3 compared to 2016 is due to several factors. A higher forecast of degree days contributes an increase of 1.3 10^6m^3. The grassroots methodology revealed a higher expectation of 2017 consumption particularly in the industrial sector, and overall, this contributed to an increase of 20.5 10^6m^3. Four new customers are expected to gain service on Rate 110, adding 13 10^6m^3. This is offset by a 2.9 10^6m^3 loss from three customers. Transfer losses and gains refer to migration between General Service (Rate 6) and Contract rates, as well as transfers among rates within the contract market. The impact from these flows is a net increase of 46.5 10^6m^3, with a significant gain particularly in Rate 110 volumes.
This migration is mainly driven by the lower load factor requirement for Rate 110 service (from 50% to 40% as filed at EB-2012-0459, Exhibit H1, Tab 2, Schedule 3).

Witness: M. Suarez

BOMA INTERROGATORY #5

INTERROGATORY

Ref: Exhibit C1, Tab 2, Schedule 1, Page 5

What is the actual number of contract customers unlocked as of September 30, 2016?

RESPONSE

The methodology for forecasting volumes and all inputs to the volumetric determination utilizes the last full year of actual data at the time that forecasts are developed for the rate application. This approach has been applied consistently for ratemaking purposes.
For the 2017 forecast, actual data up to and including 2015 were utilized. From that standpoint, it is the Company's position that partial year information is not indicative of full year results, and is therefore not appropriately used to inform test year expectations.

Witnesses: R. Cheung
M. Suarez

BOMA INTERROGATORY #6

INTERROGATORY

Ref: Ibid

Why did the migration from bundled to unbundled (Rate 125, Rate 300 Firm) occur?

RESPONSE

As stated in the Company's pre-filed evidence at Exhibit C1, Tab 2, Schedule 1, page 6, paragraph 14, customer migration from bundled to unbundled rate classes began in 2007 as a result of the Board decision on the Natural Gas Electricity Interface Review EB-2005-0551 ("NGEIR Decision") proceeding on November 7, 2006. On November 22, 2006, Enbridge filed draft Rate Schedules for Rates 125, 300, 315 and 316, which are the unbundled rates that were approved in the NGEIR proceeding. Customers subsequently assessed service under the unbundled rates and migrated accordingly.

Witnesses: R. Cheung
M. Suarez

BOMA INTERROGATORY #7

INTERROGATORY

Ref: Ibid, Page 10

Please compare paragraph 23 statement that 2017 will have higher average use per customer in rate 1 with figure 2 on page 8, which shows lower average use per customer.

RESPONSE

The statement referred to is not specific to Rate 1 average use, rather it is a reference to overall General Service average use (i.e., Rate 1 plus Rate 6 volumes divided by Rate 1 plus Rate 6 customers) and the resultant volumetric impact. In other words the increase in Rate 6 average use is partially offset by the decline in Rate 1 average use, resulting in an increase to overall General Service average use and thus an increase in General Service volumes.

Within the same exhibit (Exhibit C3, Tab 2, Schedule 3, page 3, Column 4), the higher net General Service average use per customers results totaling 34.0 10^6m^3 is the result of the increase of Rate 6 average use of 78.1 10^6m^3 (line 1.2), partially offset by the decline in the Rate 1 average use 44.1 10^6m^3 (line 1.1). The decline in Rate 1 average use per customer is consistent with the trend shown at Figure 2, page 8 of the same exhibit.

Witnesses: M. Suarez
H. Sayyan

BOMA INTERROGATORY #8

INTERROGATORY

Ref: Exhibit C1, Tab 2, Appendix A

Please add a column to the table showing the actual (un-normalized) average use for rates 1 and 6.

RESPONSE

The table on the following page adds the actual un-normalized average uses to Table 3 of Exhibit C1, Tab 2, Schedule 1, Appendix A.

Witnesses: M. Suarez
H. Sayyan

GENERAL SERVICE SYSTEM-WIDE TOTAL AVERAGE USE

		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 10	Col. 11	Col. 12
		2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016 Board-Approved Budget	2017 Forecast
Rate 1 Normalized Average use		2,769	2,758	2,710	2,680	2,619	2,568	2,559	2,538	2,534	2,512	2,495	2,472
	Change		(11)	(48)	(30)	(61)	(51)	(9)	(21)	(4)	(22)	(17)	(23)
	% Change		-0.40%	-1.74%	-1.11%	-2.28%	-1.95%	-0.35%	-0.82%	-0.16%	-0.87%	-0.68%	-0.92%
Rate 6 Normalized Average use		21,807	23,110	25,531	27,394	29,514	29,468	29,332	29,096	29,313	29,641	28,916	29,058
	Change		1,303	2,421	1,863	2,120	(46)	(136)	(236)	217	328	(725)	142
	% Change		5.98%	10.48%	7.30%	7.74%	-0.16%	-0.46%	-0.80%	0.75%	1.12%	-2.45%	0.49%
Rate 1 Un-normalized Average use		2,655	2,809	2,765	2,723	2,490	2,607	2,301	2,560	2,830	2,588	2,480	2,472
	Change		154	(44)	(42)	(233)	117	(306)	259	270	(242)	(108)	(8)
	% Change		5.81%	-1.55%	-1.51%	-8.56%	4.70%	-11.75%	11.26%	10.55%	-8.55%	-4.18%	-0.33%
Rate 6 Un-normalized Average use		21,058	23,737	26,284	27,954	28,340	30,002	26,655	29,577	32,805	30,596	28,753	29,058
	Change		2,679	2,547	1,670	386	1,662	(3,347)	2,922	3,228	(2,208)	(1,843)	305
	% Change		12.72%	10.73%	6.35%	1.38%	5.86%	-11.16%	10.96%	10.91%	-6.73%	-6.02%	1.06%

Witnesses: M. Suarez
H. Sayyan

CME INTERROGATORY #1

INTERROGATORY

Ref: Exhibit C1, Tab 1, Schedule 1, page 1 of 3, Table 1

At Table 1, EGD provides a comparison of Utility Operating Revenue. That Table shows the 2016 Board-approved Operating Revenue was $2,954.0 Million. The 2017 Updated Forecast of Operating Revenue is approximately $105 Million less at $2,768.1 Million. CME wishes to better understand why the 2016 Board-approved Operating Revenue is so much greater than the 2017 Updated Forecast. Please set out all of the drivers for the differences between the 2016 Board approved Operating Revenue as compared to the 2017 Updated Forecast Operating Revenue.

RESPONSE

The 2017 Updated Forecast Operating Revenue of $2,768.1 million is $185.9 million lower than the 2016 Board Approved Operating Revenue of $2,954.0 million, primarily within the forecast gas sales and transportation revenues categories.

The primary driver for the reduction in sales and transportation revenue is the gas commodity prices embedded in approved existing rates used to forecast revenues within the two forecasts. As stated in the Company's pre-filed evidence at Exhibit C1, Tab 1, Schedule 1, paragraph 5, the 2017 Updated Forecast Gas Sales and Transportation Revenue was determined using the EB-2016-0184 commodity rates set out in the July 2016 QRAM, which is lower than the commodity rates set out for the 2016 Board Approved Gas Revenues. The impact of lower commodity rates in 2017 Forecast has reduced the total gas revenue by $235.8 million. The reduction in gas revenue is partially offset by the higher forecasted volumes and number of customers in 2017, as compared to the 2016 Board Approved Budget, as shown in Exhibit C1, Tab 2, Schedule 1, pages 1 and 2. The increase in the total forecast volumes and average number of customers in 2017, increase the 2017 Updated Forecast Operating Revenue by $49.9 million.

Witness: M. Suarez

CME INTERROGATORY #2

INTERROGATORY

Ref: Exhibit C1, Tab 2, Schedule 1, pages 1 and 2 of 12

At Table 1, EGD sets out a Summary of Gas Sales and Transportation Volumes which include 2015 Actual, 2016 Board-approved Budget, and 2017 Budget. That Table shows that the Total Volumes, Gas Sales and Transportation for 2015 was actually 11,931.8 10^6m^3. The 2017 Budget is 11,752.2 10^6m^3. While the 2017 Budget for Total Volumes, Gas Sales and Transportation is less than the 2015 Actual, EGD goes on to show at Table 2 that the Total Number of both General Service Customers and Contract Market Customers are anticipated to increase from 2015 Actual as compared to the 2017 Budget. CME wishes to understand why EGD anticipates that the Total Volumes, Gas Sales and Transportation will decrease in 2017 while the Average Number of Customers increases. Please provide an explanation as to why the 2017 Budget for Total Volumes, Gas Sales and Transportation is less than the 2015 Actual while the Average Number of Customers is increasing over the same time period.

RESPONSE

The total volumes listed in Table 1 represent un-normalized volumes. The volumetric decrease of 179.6 10^6m^3 between 2015 Actual and 2017 Forecast is made up of a decrease in General Service volumes of 229.9 10^6m^3 that is partially offset by the increase in Contract Market volumes of 50.3 10^6m^3. The decrease in General Service volumes of 229.9 10^6m^3 from 2015 Actual to 2017 Forecast is primarily driven by lower degree days forecasted in 2017 versus the actual 2015 degree days. The 2017 Forecast Degree Day of 3,639 is 71 degree days lower than the 2015 Actual Degree Day of 3,710. The decrease in General Service volumes is also driven by a slight decline in normalized average use per customer. The higher number of customers forecasted (an increase of 59,243 in 2017 as compared to 2015 Actual) have partially offset the volumes reduction driven by the two factors as mentioned above.

Witness: M. Suarez

	2015 Actual	2017 Budget	2017 Budget vs 2015 Actual
General Service Volumes	10 003.9	9 774.0	(229.9)
Contract Market Volumes	1 927.9	1 978.2	50.3
Total Volumes, Gas Sales and Transportation	11 931.8	11 752.2	(179.6)
Degree Day (Central)	3 710	3 639	(71.0)
Customers, Gas Sales and Transportation (Average)	2 094 681	2 153 924	59 243

Witness: M. Suarez

ENERGY PROBE INTERROGATORY #4

INTERROGATORY

References: Exhibit C1, Tab 1, Schedule 1, Page 1, Table 1 and Exhibit C1, Tab 2, Schedule 1, Page 1, Table 1 and Exhibit C1, Tab 2, Schedule 1, Page 5, Figure 2

Preamble: Enbridge is experiencing a decade-long decline in average gas consumption among residential customers - down nearly 11% since 2006.

a) Can Enbridge explain the reason(s) for the NAC decline? Has the company completed any reports or detailed analysis on that decline? If so, please provide copies.

b) Do Enbridge's 2017 forecasts include the impact that cap and trade may have on gas consumption?

RESPONSE

a) Residential normalized average use has declined consistently in Ontario for over 10 years. This trend reflects the combined and cumulative impacts of government policies to improve energy efficiency through the Energy Efficiency Act and through thermal efficiencies from changes to the Building Code, long-standing Demand-Side Management programs, rapid housing growth and sustained customer growth.

   The Company continues to monitor the drivers that impact residential average use through its annual assessment of average use models, and the drivers have remained consistent over time.

b) Enbridge's 2017 forecasts do not include the impact of Cap and Trade on gas consumption. Please see response to VECC Interrogatory #3 at Exhibit I.C2.EGDI.VECC.3.

Witness: M. Suarez

ENERGY PROBE INTERROGATORY #5

INTERROGATORY

References: Exhibit C1, Tab 2, Pages 8, 9 and Appendix A

a) What are forecast impacts (quantitative -M^3) of Residential Rate 1 customer Normalized Average Consumption (NAC) due to changes in customer bills in 2017 as a result of GHG responsibility costs.

b) What are forecast impacts (quantitative-M^3) on Rate 6 Customer NAC due to changes in customer bills in 2017 as a result of GHG responsibility costs.

c) Did EGD apprise existing and new industrial customers regarding Cap and Trade and related increased bills prior to its 2017 consumption forecast? Please provide details including any relevant documents

RESPONSE

a), b & c)

Please see the responses to Energy Probe Interrogatory #1 at Exhibit I.A1.EGDI.EP1 and VECC Interrogatory #3 at Exhibit I.C2.EGDI.VECC.3.

Witness: M. Suarez

ENERGY PROBE INTERROGATORY #6

INTERROGATORY

References: Exhibit C1,Tab 2, Schedule 1, Appendix A Table 2 and Table 4;

Preamble: 2017 Forecast shows NAC increases of 2.99% in the apartment sector and 3.53% in the industrial sector

a) Explain/breakout the factors driving forecast 2.99% Increase in NAC in the apartment sector.

b) Specifically estimate DSM impacts on NAC:
   i. List DSM programs and costs for the apartment sector
   ii. Forecast of savings from apartment DSM programs
   iii. Quantify other factors offsetting DSM savings.

c) Please explain/breakout the factors driving the 3.53% forecast increase in Industrial NAC in 2017.

d) Specifically estimate DSM Impacts
   i. List major DSM programs and costs for the industrial sector
   ii. Forecast of savings from industrial DSM programs
   iii. Quantify other factors offsetting DSM savings.

RESPONSE

a) and c)

The change in average use for 2017 as calculated in Column 12 is the percentage change from the 2016 Board Approved Budget shown in Column 11. The 2016 Board Approved Budget was developed in an earlier proceeding using the actuals to 2014, and the assumptions from 2015 Winter Economic Outlook; while 2017 forecast is developed using the actuals to 2015 and the assumptions from 2016 Spring Economic Outlook. As a result, the percentage change in Column 12 at Table 2 is not reflective of the average use trend.

Witnesses: S. Moffat
B. Ott
M. Suarez

As shown in the following table, using the same actual data to 2015 as well as the same Economic Outlook assumptions as 2017 forecast for 2016, the re-estimated 2016 average use forecast generated by the models is 3.2% and 2.0% higher than the 2016 Board Approved Budget respectively for the apartment and industrial sectors. The change in 2017 average use from the re-estimated 2016 is -0.2% for the apartment and 1.5% for the industrial sector. The average use for both the apartment and industrial sector within Rate 6 is expected to be relatively flat, however the addition of two Rate 6 industrial customers contributed to the overall industrial average use increase in 2017.

Normalized Average use	Col.1	Col.2	Col.3
	2016 Budget	2016 Estimate	2017 Forecast
Apt	145,956	150,558	150,321
			-0.2%
Ind	109,843	112,003	113,715
			1.5%

b)

i. Enbridge's DSM programs and budgets, as approved in EB-2015-0049, are designed and delivered based on the varying needs of the Company's customers. As such, volumes and costs are not grouped in the same manner as they are for load forecasting purposes (i.e., residential, industrial, apartment, and commercial). Adjusting DSM program budgets to approximate the aforementioned grouping indicates a budget of $6.2 million in 2017 for the apartment sector.

The programs which serve this customer segment are as follows (EB-2015-0049 Exhibit B, Tab 1, Schedule 4, pages 8 and 18):

- Custom Commercial: Financial incentives and technical assistance for customized natural gas reduction projects.
- Commercial & Industrial Prescriptive Incentive Offer: Financial incentives for a set list of natural gas reducing measures, typically with pre-determined incentive amounts and estimated savings.
- Low Income Multi-Residential – Affordable Housing Program: A variety of custom and prescriptive incentives for natural gas saving measures, energy audit incentives, and in-suite direct install activities.

Witnesses: S. Moffat
B. Ott
M. Suarez

ii. Forecast DSM savings of 5,530,195 m^3 were applied to forecast apartment sector volumes for 2017 which equates to a 737 m^3 reduction to apartment sector average use.

iii. An upswing in economic activity relative to forecast and/or lower gas prices than forecast would be expected to cause higher average use relative to forecast. These are some factors that could have the impact of offsetting forecast DSM savings.

d)

i. Enbridge's DSM budget for the industrial sector in 2017 is $4.2 million. The programs which serve this customer segment are as follows (EB-2015-0049 Exhibit B, Tab 1, Schedule 4, pages 8 and 26):

- Custom Industrial: Financial incentives and technical assistance for customized natural gas reduction projects.
- Commercial & Industrial Prescriptive Incentive Offer: Financial incentives for a set list of natural gas reducing measures, typically with pre-determined incentive amounts and estimated savings.
- Commercial & Industrial Direct Install Offer: Financial incentives for a set list of natural gas reducing measures, covering 50 to 100% of total project costs. Enbridge can facilitate 'turnkey' installation (i.e., provide a contractor) if desired.
- Energy Leaders Initiative: Increased incentives and specialized program elements for customers that are already energy efficient.
- Comprehensive Energy Management: Comprehensive offer for large and complex commercial and industrial customers which seeks to establish visible energy inputs so as to create a corporate culture of sustainability through senior management commitment and identification of all opportunities for gas savings in a customer's facility.

ii. Forecast DSM savings of 2,602,655 m^3 were applied to forecast industrial sector volumes for 2017 which equates to a 440 m^3 reduction to industrial sector average use.

iii. An upswing in economic activity relative to forecast, lower gas prices than forecast or greater than expected migration of customers from contract rates to Rate 6 are factors that would be expected to cause higher average use relative to forecast. These are some factors that could have the impact of offsetting forecast DSM savings.

Witnesses: S. Moffat
B. Ott
M. Suarez

VECC INTERROGATORY #2

INTERROGATORY

Reference: C1/T2/S1 & C2/T1/S4

a) Please provide the actual annual year end customers by rate class for the years 2010 to 2015.

b) Please provide the actual annual average year number of customers by rate class for the years 2010 to 2015.

RESPONSE

a) The following Table 1 shows the actual year-end number of customers by rate class from 2010 to 2015.

TABLE 1
ANNUAL YEAR END NUMBER OF CUSTOMER METERS BY RATE CLASS

	2010 Customers (Year End)	2011 Customers (Year End)	2012 Customers (Year End)	2013 Customers (Year End)	2014 Customers (Year End)	2015 Customers (Year End)
Rate						
Rate 1	1 786 993	1 822 016	1 855 883	1 888 078	1,918,986	1 948 325
Rate 6	149 417	158 709	160 177	162 438	164,143	165 128
Rate 9	17	8	8	8	7	6
Rate 100	24	8	6	1	1	2
Rate 110	209	201	196	189	208	260
Rate 115	31	24	27	26	26	24
Rate 125	4	4	4	5	4	5
Rate 135	42	41	40	42	43	45
Rate 145	182	112	106	101	62	42
Rate 170	38	36	34	36	30	27
Rate 200	1	1	1	1	1	1
Rate 300	9	8	4	3	2	2
Total	1 936 967	1 981 168	2 016 486	2 050 928	2 083 513	2 113 867

Witness: M. Suarez

b) The following Table 2 shows the actual average number of customers by rate class from 2010 to 2015.

TABLE 2
ANNUAL AVERAGE NUMBER OF CUSTOMER METERS BY RATE CLASS

Rate	2010 Customers (Average)	2011 Customers (Average)	2012 Customers (Average)	2013 Customers (Average)	2014 Customers (Average)	2015 Customers (Average)
Rate 1	1 772 503	1 802 578	1 836 267	1 869 324	1 901 207	1 930 657
Rate 6	153 209	157 323	158 199	160 257	162 229	163 634
Rate 9	23	11	8	8	7	6
Rate 100	35	15	7	4	2	2
Rate 110	213	205	200	192	191	227
Rate 115	32	28	27	27	30	25
Rate 125	4	4	4	5	4	5
Rate 135	36	42	39	41	43	42
Rate 145	188	126	110	104	86	52
Rate 170	41	37	36	35	34	26
Rate 200	1	1	1	1	1	1
Rate 300	9	8	5	3	2	2
Total	1 926 294	1 960 378	1 994 903	2 030 001	2 063 836	2 094 679

Witness: M. Suarez

BOMA INTERROGATORY #9

INTERROGATORY

Ref: Exhibit C2, Tab 1, Schedule 1

What is the Q2 Economic Outlook based on? What sources are used to determine these forecasts? Please compare them to the most recent Bank of Canada numbers (October 2016 Monetary Policy Report).

RESPONSE

The Economic Outlook is a compilation of consensus forecasts for various indicators of economic conditions in Canada, the US, and Ontario as shown on page 1. Consensus forecasts are straight averages of forecasts from financial institutions, the Conference Board of Canada, and other forecast providers.

On the other hand, regional forecasts on page 2 are generated by in-house regression models informed by the Ontario consensus forecast. This level of forecast granularity is not available publicly, but is necessary to recognize the divergent conditions that sometimes exist within the Company's franchise.

The Bank of Canada (the "Bank") is not included in the Company's consensus forecast as they only provide a subset of the indicators of interest for Canada and the US. Although the Bank provides forecasts for exports and imports as well as housing, they are either not adjusted for real values, or inconsistent with the series reported by other forecasters. The Bank of Canada does not have forecasts for Ontario nor the regions.

For comparison purposes, forecasts from the Company's Q2 Economic Outlook are shown on the next page alongside the Bank of Canada's Monetary Policy Reports from Q2, Q3, and Q4.

Witnesses: M. Suarez
H. Sayyan

CANADA & U.S.								
	Economic Outlook-Q2		Bank of Canada-Q2		Bank of Canada-Q3		Bank of Canada-Q4	
CALENDAR YEAR	2016F	2017F	2016F	2017F	2016F	2017F	2016F	2017F
REAL GDP (% CHANGE)								
CANADA	1.6	2.2	1.7	2.3	1.3	2.2	1.1	2.0
U.S.	2.1	2.4	2.0	2.1	2.0	2.1	1.5	2.1
CANADA REAL EXPORTS (% CHANGE)	4.0	3.9						
CANADA REAL IMPORTS (% CHANGE)	-0.7	3.0						
CANADA HOUSING STARTS (000's)	185.0	175.7						
CANADA UNEMPLOYMENT RATE (%)	7.2	7.0						
CANADA EMPLOYMENT GROWTH (% CHANGE	0.5	0.9						
CONSUMER PRICES (% CHANGE)								
CANADA	1.6	2.2	1.4	1.9	1.6	2.1	1.5	1.9
U.S.	1.4	2.5						

Witnesses: M. Suarez
H. Sayyan

BOMA INTERROGATORY #10

INTERROGATORY

Ref: Exhibit C2, Tab 1, Schedule 3, Page 7

Why are the rate 6 percentage variations between actual and forecast larger (in both directions) than those of rate 1?

RESPONSE

Larger percentage variations are typically indicative of greater variability in the underlying data or actuals. This is particularly the case for the Rate 6 class of customers which includes small commercial, apartment, larger commercial and industrial customers. The variability within this heterogeneous class was further exacerbated by customer migration from the Contract Market to General Service over the period from 2006 to 2010 as noted at Exhibit C1, Tab 2, Schedule 1, paragraphs 19 and 20. Thereafter, rate migration has stabilized and Rate 6 average use has reflected a relatively flat trend. However, the forecast continued to be impacted by the volatile historical data.

In contrast, Rate 1 customers are relatively homogeneous, which is reflected in the variance results.

Witnesses: M. Suarez
H. Sayyan

BOMA INTERROGATORY #11

INTERROGATORY

Ref: Ibid, Page 20

Why do you use real gas prices rather than the nominal gas prices? Would consumers not focus more on nominal gas price increases?

RESPONSE

Real gas prices are used in the average use models for two reasons. Real prices take into account not just the level of gas price, but accounts for all other prices within the basket of consumer goods to reflect the portion of energy costs within a household's monthly expenses. To validate the appropriateness of this variable for modelling average use forecasts, both nominal and real gas prices were tested in the largest revenue class average use model. The results showed that real gas prices were statistically significant, while nominal prices were not.

Witnesses: M. Suarez
H. Sayyan

BOMA INTERROGATORY #12

INTERROGATORY

Ref: Exhibit C2, Tab 1, Schedule 4

Please provide actual 3Q customer additions per Table 1

RESPONSE

The methodology for forecasting volumes and all inputs to the volumetric determination utilizes the last full year of actual data at the time that forecasts are developed for the rate application. This approach has been applied consistently for ratemaking purposes.
For the 2017 forecast, actual data up to and including 2015 were utilized. From that standpoint, it is the Company's position that partial year information is not indicative of full year results, and is therefore not appropriately used to inform test year expectations.

Witness: F. Ahmad

ENERGY PROBE INTERROGATORY #7

INTERROGATORY

Reference: Exhibit C2, Tab1, Schedule 4, pg.2

a) Please provide an update to the customer addition forecast related to the Community Expansion projects, including # of customers connected in 2016 and #customers projected to be connected in 2017. Compare to original CE forecast of 1590 customers

b) Please update the CE approved and planned Leave to Construct Applications, for 2016-2018, specifically: Fenelon Falls, Bobcaygeon, Kirkfield, Scugog Island, and Lanark & Balderson.

c) What are the forecast communities and# of customers projected for 2018?

RESPONSE

a) The Board's decision on the Community Expansion ("CE") generic proceeding has not yet been issued. Enbridge has not included customer additions from any CE projects for 2017. The CE forecast of 1,590 customers in Enbridge's 2016 Rate Adjustment Application (EB-2015-0114) was subsequently removed during the settlement process.

b) Enbridge has not filed any Leave to Construct ("LTC") applications with respect to Community Expansion projects pending the Board's decision on the generic proceeding. No update is available on either CE or planned LTC's at this time.

c) Please refer to the response at part a) and b) above.

Witness: F. Ahmad

SEC INTERROGATORY #1

INTERROGATORY

[C2-1-4, p.3]

Please add two columns to Table 1, providing Q1 through Q3 gross customer additions for both 2015 and 2016.

RESPONSE

The methodology for forecasting volumes and all inputs to the volumetric determination utilizes the last full year of actual data at the time that forecasts are developed for the rate application. This approach has been applied consistently for ratemaking purposes. For the 2017 forecast, actual data up to and including 2015 were utilized. From that standpoint, it is the Company’s position that partial year information is not indicative of full year results, and is therefore not appropriately used to inform test year expectations.

Witness: F. Ahmad

VECC INTERROGATORY #3

INTERROGATORY

Reference: C2/T1/S1/pg.22

a) EGD notes that Cap & Trade is not explicitly modelled into the average use forecast. Given C&T is expected to increase natural gas prices why would the associated increased gas price not be incorporated into the model?

b) Is EGD looking at methods of including the impact of the government's greenhouse gas policies into its forecast modelling? If so when might these proposed modifications to the model be implemented?

RESPONSE

a) At the time that the volumetric forecasts were being developed, limited information was available on the Cap and Trade framework and the assumptions that needed to be included to project volumes. Volume forecasts initiate the budget process, and in the absence of guidelines, the uncertainty around carbon price, and the desire to keep to the regulatory filing schedule, Cap and Trade impacts were not incorporated.

b) With the recent Report of the Board on the "*Regulatory Framework for the Assessment of Costs of Natural Gas Utilities*' *Cap and Trade Activities*" on September 26, 2016, it is expected that carbon price projections can be included in gas price projections in time for the modelling of 2018 volumes. The Company would note that aside from direct price signals which can be easily captured in the development of the volumes budget, there are other factors not so easily modelled such as, *inter alia*, Building Code changes, self-induced conservation efforts and changes in behavior (which may be induced by Government policy or programs). Thus, while the direct price impact of Cap and Trade (reflected in increases to delivery charges) can be modeled, the overall impact will be more difficult to forecast.

Witnesses: H. Sayyan
M. Suarez

BOARD STAFF INTERROGATORY #8

INTERROGATORY

Ref: D1/T1/S1/para11

Please confirm that there are no O&M-related cap and trade costs embedded in the 2017 rate application.

RESPONSE

Confirmed. There are no O&M (or capital) costs related to cap and trade included within the 2017 rate application, or in the derivation of 2017 allowed revenues.

Witness: R. Small

BOARD STAFF INTERROGATORY #9

INTERROGATORY

Ref: D1/T1/S2/p 2 of 2

With respect to the pension and OPEBs accrual update for 2017, what are the main drivers of the decrease of $3.8 million vs the 2017 placeholder?

RESPONSE

The decrease of $3.8 million in total pension and OPEB accrual costs was primarily a result of a change in the estimation of discount and interest rates for calculating benefit obligations, service cost, and interest on these items, referred to as the split rate approach in Exhibit D1, Tab 5, Schedule 1, Appendix 1 page 2.

Witnesses: J. Shem
R. Small

BOARD STAFF INTERROGATORY #10

INTERROGATORY

Ref: D1/T2/S3/para8

Given that contracting for 2017 winter Peaking Supplies has now taken place, please provide an update to the Peaking Supplies, including the impact on gas costs for 2017.

RESPONSE

The Company has completed contracting for its 2017 winter Peaking Supply requirements. Consistent with prior years during this Custom IR term, the peaking contract pricing (i.e., demand charges and index commodity prices) will be incorporated into gas costs as part of the derivation of the January 1, 2017 QRAM Reference Price.

Any variance from the forecasted index prices, including exchange rates, and the actual cost for peaking service will be captured in the 2017 Purchased Gas Variance Account.

Witnesses: M. Kirk
D. Small

BOARD STAFF INTERROGATORY #11

INTERROGATORY

Ref: D1/T2/S3/para13

Please list and quantify the cost consequences in landed cost terms of the movement from long haul to short haul contracting with TCPL, OEB-approved 2016 vs 2017 proposed.

RESPONSE

The table below summarizes the cost consequences of three shifts from long haul to short haul contracting.

The first evaluation compares long haul TCPL from Empress to Enbridge CDA against short haul service on Union M12 from Dawn to Parkway ("EGT"). The second compares long haul TCPL from Empress to Enbridge CDA against short haul service on Union M12 from Dawn to Union Parkway Belt plus TCPL from Union Parkway Belt to Enbridge CDA. The third comparison is between long haul TCPL from Empress to Enbridge EDA and short haul service on Union M12 from Dawn to Parkway and TCPL from Parkway to Enbridge EDA.

EB-2016-0215 - Enbridge CDA: Long Haul vs M12 Landed Cost

Pipeline/Service[1]	Path	Pricing Point[2]		2017 Landed Cost (C$/GJ)
TCPL/FT-LH	Empress-to-Enbridge CDA	Empress	=	4.84
Union/M12	Dawn-to-Enbridge EGT	Dawn	=	3.94
		Difference	=	*(0.90)*

EB-2016-0215 - Enbridge CDA: Long Haul vs Short Haul Landed Cost

Pipeline/Service[1]	Path	Pricing Point[2]		2017 Landed Cost (C$/GJ)
TCPL/FT-LH	Empress-to-Enbridge CDA	Empress	=	4.84
Union/M12 & TCPL/FT-SH	Dawn-to-Union Parkway Belt-to-Enbridge CDA	Dawn	=	4.16
		Difference	=	*(0.68)*

EB-2016-0215 - Enbridge EDA: Long Haul vs Short Haul Landed Cost

Pipeline/Service[1]	Path	Pricing Point[2]		2017 Landed Cost (C$/GJ)
TCPL/FT-LH	Empress-to-Enbridge EDA	Empress	=	4.90
Union/M12 & TCPL/FT-SH	Dawn-to-Parkway-to-Enbridge EDA	Dawn	=	4.50
		Difference	=	*(0.40)*

[1] Pipeline/Service costs reflect information available as of: June 1, 2016

[2] Pricing Point calcuated using 21-day moving average from: May 3, 2016 - May 31, 2016

Witnesses: M. Kirk
D. Small

BOARD STAFF INTERROGATORY #12

INTERROGATORY

Ref: D1/T2/S3/para18

How does Enbridge propose to manage regulatory issues in regards to its affiliate relations in terms of its transactions with Union Gas Limited, for example with M12 and M12X services?

RESPONSE

Enbridge is not an affiliate with Union Gas Limited and any contracts or transactions that are with Union Gas for 2017 have been negotiated and executed as arms-length transactions.

Witnesses: K. Culbert
D. Small

BOARD STAFF INTERROGATORY #13

INTERROGATORY

Ref: D1/T2/S9/p1 of 2

Please update the list of transportation and storage contracts for any changes in contracting since the filing of the application.

RESPONSE

As shown at Exhibit D1, Tab 2, Schedule 9, page 1, Item 20, the contracted Nova capacity for 86,869 GJ/day was scheduled to expire October 31, 2017 and a decision with respect to renewal was required by October 31, 2016. The Company chose to renew 50,000 GJ/day of Nova Transmission capacity for one year - November 1, 2017 to October 31, 2018 – with a renewal date of October 31, 2017.

Similarly, a number of Union M12 contracts (Items 29, 31, 33, 34, and 35) were subject to a renewal date of October 31, 2016 to extend the expiry date beyond October 31, 2018. The Company has chosen to renew all of these contracts for another year to October 31, 2019. A decision on whether or not to renew these contracts beyond that date will be required prior to October 31, 2017.

The Company also entered into a short term transportation arrangement with Vector for 50,000 Dth/day for the period December 1, 2016 to February 28, 2017.

At this point the Company has not completed its RFP process with respect to the storage contracts scheduled to expire March 31, 2017.

Please refer to the updated version of Exhibit D1, Tab 2, Schedule 9, page 1 which was filed on November 7, 2016. Changes discussed above appear in red in the updated schedule and any cost consequences of those changes will be captured as a part of the QRAM process.

Witness: D. Small

BOARD STAFF INTERROGATORY #14

INTERROGATORY

Ref: D1/T2/S11/para10

Please update the status of TCPL's King's North project in-service date. The evidence indicates that King's North is currently expected to be in-service at the end of November 2016. Please elaborate on the implications of a further delay of in-service of King's North on the Company's application for 2017 rates. Please include a discussion of any impacts on the requested GTA-related deferral account.

RESPONSE

King's North Gas Supply Impact

TransCanada published a notice on October 12, 2016 indicating that:

> [t]he King's North Connection Project is expected to be completed and in service, subject to the process of acquiring NEB approval of the Leave to Open, November 1, 2016. The Station 130 Unit Addition is anticipated to be in service early December 2016, subject to construction and NEB approval of the Leave to Open.[1]

On November 2, 2016, the National Energy Board approved TransCanada's Leave to Open application for the King's North Connection Project subject to certain conditions. Construction on the Station 130 Unit Addition is ongoing.

On November 9, 2016, TransCanada issued a bulletin providing an update on the King's North Connection Project, stating that "the facilities are expected to be fully commissioned within the next ten days, with the actual timing dependent on operating conditions". The bulletin also provided an update on the Station 130 Unit Addition Project, stating it "is anticipated to be in service by the middle of December 2016", but notes "this is still subject to construction and NEB approval of a Leave to Open".[2]

Both the King's North Connection Project and the Station 130 Unit Addition are required to be in service prior to the Company's contract for 170,000 GJ per day of firm transportation from Union Parkway Belt to the Enbridge EDA coming into service.

[1] http://www.nrgexpressway.com/servlet/nrginfo.ew.notices.ShowNotice?bulletin_id=310499101
[2] http://www.nrgexpressway.com/servlet/nrginfo.ew.notices.ShowNotice?bulletin_id=310973001

Witnesses: M. Kirk
D. Small
R. Small

If the in-service date is delayed beyond January 1, 2017 any variances in transportation cost would be captured as part of the 2017 Purchase Gas Variance Account.

King's North GTA Related Deferral Account Impact

With regards to the recovery of the approved forecast of costs related to Segment A of the Company's GTA project, within this application rates are proposed which would recover 60% of the costs from Rate 332 transportation customers, and 40% from bundled customers, as was approved in the GTA Project Leave to Construct proceeding, EB-2012-0451. In order for the Company to be able to provide Rate 332 transportation service, TransCanada's King's North Connection Project must be in service. The expectation at the time of filing this rate application was that King's North would be in service for all of 2017, but there was no certainty that it would not be delayed. As a result of the uncertainty, the Company proposed the continuation of the Greater Toronto Area Incremental Transmission Capital Revenue Requirement Deferral Account ("GTAITCRRDA") and a revised Rate 332 Deferral Account ("R332DA") in 2017, to allow for the recovery of forecast GTA Segment A costs in the event that King's North in-service date was delayed into 2017. With the National Energy Board's approval of TransCanada's Leave to Open application on November 2, 2016, Rate 332 transportation is expected to begin at some point during November 2016. With the anticipated commencement of Rate 332 transportation service, neither the GTAITCRRDA nor R332DA is expected to be required in 2017.

Witnesses: M. Kirk
D. Small
R. Small

BOARD STAFF INTERROGATORY #15

INTERROGATORY

Ref: D1/T3/S1/para8

With respect to the Customer Care and CIS allowed revenues for 2017, please summarize the main drivers and associated amounts behind the decrease of $4.7 million compared to 2016.

RESPONSE

As detailed in paragraph 8 of the referenced exhibit, the 2017 Customer Care and CIS allowed revenue requested for recovery within this proceeding, of $126.6 million, reflects an increase of $4.2 million when compared to the 2016 approved amount of $122.4 million.

As per the terms of the Board Approved EB-2011-0226 Settlement Agreement, the amount of revenue requirement (or allowed revenue) to be recovered in rates each year, between 2013 and 2018, is to be determined annually by multiplying the forecast number of customers (which forecast will be set as part of the annual rate-setting process) for that year by the smoothed revenue requirement per customer for that year (as shown on page 12 of the Settlement Agreement and Line 24 of the updated template shown on page 43 of the Settlement Agreement, which is attached as Exhibit D1, Tab 3, Schedule 2 in this proceeding). As a result of the approved smoothed Customer Care and CIS cost recovery methodology, the drivers causing the $4.2 million increase in 2017 allowed revenues, as compared to the 2016 amount, are the higher forecast 2017 number of customers, and the higher 2017 smoothed cost per customer. The 2017 Customer Care and CIS allowed revenue of $126.6 million is derived by multiplying the 2017 forecast number of customers (as updated in this proceeding) of 2,168,434, by the EB-2011-0226 approved 2017 smoothed cost per customer of $58.36, while the 2016 Customer Care and CIS allowed revenue of $122.4 million was derived by multiplying the 2016 forecast number of customers (as updated in EB-2015-0114) of 2,143,429, by the EB-2011-0226 approved 2016 smoothed cost per customer of $57.11. Exhibit D1, Tab 3, Schedule 3 provides an updated Customer Care and CIS template which summarizes the information above, in Columns M (2017) and L (2016), at Rows 24 (smoothed cost per customer), 25 (updated forecast number of customers per year), and 27 (total allowed revenue by year).

Witnesses: D. McIlwraith
R. Small

BOMA INTERROGATORY #13

INTERROGATORY

Ref: Exhibit D1, Tab 2, Schedule 2, Page 8

Why is no attempt made to forecast migration between Direct Purchase and Sales service?

RESPONSE

The discussion at Exhibit D1, Tab 2, Schedule 2, page 8 deals with forecast methodology for calculating the budgeted demand. For purposes of demand forecasting it is irrelevant if a distribution customer is direct purchase or sales service. It is however, necessary to make this distinction for determining the supplies available to the Company to satisfy that demand. Therefore, for gas costing purposes there is a breakdown of direct purchase and sales service which includes any forecasted migration between the two types of service. This breakdown is seen, for example, in the evidence at Exhibit C3, Tab 2, Schedule 1.

Witnesses: D. Small
M. Suarez

BOMA INTERROGATORY #14

INTERROGATORY

Ref: Ibid, Page 15

How often does EGD use "approved suppliers"?

RESPONSE

Enbridge interprets the interrogatory as referring to the following statement:

“If additional supply is required for the upcoming month, it will be procured on a monthly basis through a Request for Proposal process, electronic trading systems (i.e., NGX) or directly from approved suppliers.”

Enbridge maintains a list of credit worthy counterparties from whom it will purchase gas. When purchasing gas through an RFP process, i.e., seasonal/monthly supplies, Enbridge will only purchase gas from counterparties on the list of approved suppliers. When purchasing gas on the day, Enbridge may contact approved suppliers directly or make use of an electronic trading board like NGX. The approach taken depends on, among other things, timing, volumes required, location and counterparty availability. Where the transactions are with an approved supplier, the prices are similar to what is posted on NGX for similar transactions.

Witness: D. Small

BOMA INTERROGATORY #15

INTERROGATORY

Ref: Ibid, Page 17

(a) How much Michigan storage does EGD hold, with what company(ies)?

(b) Please explain how that gas is transported to the EGD service area, or to Tecumseh storage from the Michigan sites.

(c) Has EGD utilized, transported to the franchise, any of the Michigan gas?

(d) Is the availability of the gas in storage in Michigan "equally available" as gas stored at Union or Tecumseh, or are there deliverability or transportation constraints? Please compare "deliverability ratios" in Michigan storage to Tecumseh and Union ratios.

(e) In general, are the market prices charged by Michigan storage providers higher or lower than those charged by Union Gas? Do they include transport to Dawn/Tecumseh, or must transport be acquired separately?

RESPONSE

a) Enbridge currently has a contract with a storage provider located in Michigan. The Company is reluctant to provide the contract particulars as disclosing such information may create an impediment when the Company goes out into the marketplace to replace that storage contract upon expiry.

In response to BOMA # 17 at Exhibit I.D1.EGDI.BOMA.17, the Company has provided a copy of the RFP that was issued this fall for storage service commencing April1, 2017. As shown on that RFP, the Company would entertain proposals whereby Enbridge would provide volumes at Dawn and receive volumes at Dawn.

b) and c)

The Company does not hold transportation capacity to and from storage facilities in Michigan. The nature of the Company's contract for storage in Michigan is such that the storage entity receives gas from Enbridge at Dawn during the summer injection period and delivers gas to Enbridge at Dawn during the winter withdrawal period.

Witness: D. Small

Therefore, physical transportation forms part of this particular storage service and the Company does not contract for transportation capacity directly to move gas to/from storage in Michigan.

d) and e)

The Company has structured its third party storage contracts such that Enbridge will be entering the market place every year to replace a level of storage and by doing so can take advantage of updated market pricing and deliverability requirements.

As discussed in the response to part a) of this interrogatory, the Company is reluctant to provide information related to the prices charged on its various storage contracts.

As discussed in the response to parts b) and c) of this interrogatory, transport to Dawn/Tecumseh is not required due to the nature of the storage contract in question.

Witness: D. Small

BOMA INTERROGATORY #16

INTERROGATORY

Ref: Ibid, Page 21

In what circumstances is Firm Transportation Short Notice used? For how many years has EGD been contracting for the service, and in what amounts?

RESPONSE

Enbridge entered into a Firm Transportation Short Notice (“STSN”) contract with TCPL effective January 12, 2009 for 85,000 GJ/day for transportation service from Union Parkway to the Victoria Square #2 delivery location. The reserved capacity and the 24 daily nomination windows available with this service provide additional operational flexibility should there be material changes in demand throughout the day in the Enbridge CDA.

Witness: D. Small

BOMA INTERROGATORY #17

INTERROGATORY

Ref: Ibid, Page 23

Please provide a copy of the RFP and template contract used to acquire storage from third parties at market based prices?

RESPONSE

A copy of the most recent Storage Capacity RFP letter is attached. The letter was sent to counterparties in fall 2016 for injections commencing on April 1, 2017.

Storage contracts are specific to the counterparty providing the service and, as such, no standard template is available.

Witness: D. Small

Enbridge Gas Distribution Inc.
3000 Fifth Avenue Place
425 – 1st Street S.W.
Calgary, AB T2P 3L8
Canada
www.enbridge.com

Trevor Mitchell
Senior Specialist, Gas Supply/Asset Opt.
Enbridge Gas Distribution Inc.
Tel: 403 663-6622
Fax: 403 231 5770
trevor.mitchell@enbridge.com

ENBRIDGE

November 2, 2016

Dear Sir/Ms.:

Subject: Storage at Dawn, injections commencing April 1, 2017

Enbridge Gas Distribution Inc. (Enbridge) requires firm natural gas storage services, injections commencing April 1, 2017. Enbridge requires that these storage services meet the following specifications:

Storage Services Required

Term: Up to Five years commencing April 1st, 2017. Lesser terms will be considered

Location: Enbridge will deliver gas to Storage Provider at Union Dawn for injection, and Storage Provider will re-deliver gas to Enbridge at Union Dawn for withdrawal. Alternate receipt and delivery points may be considered. Please provide details as to delivery standard (firm), and any associated transportation requirements.

Maximum Annual Storage Balance (MSB): Up to 6 PJ's

Firm Injection Schedule: At a minimum, must include the months of May through September.

Firm Withdrawal Schedule: At a minimum, must include the months of December through March.

Enhanced Storage Services: Enbridge is also interested in offers that allow greater storage flexibility, including "year-round" services. If applicable, please provide the price of these enhanced services separately.

Firm Injection Curve Rights: Must allow for at least 0.75% of MSB per day when inventory is less than 75% full.

Firm Withdrawal Curve Rights: Must allow for at least 1.2% of MSB per day when inventory is more than 25% full

Responses

Should you be interested in supplying this storage service to Enbridge, please submit a proposal stating the delivery points, term, MSB and service attributes, with the relevant pricing, including demand and commodity charges.

This storage service request may have Dodd Frank Act implications and may require specific clauses to be included in any storage agreement between the parties. Any changes, if required, will be forwarded to the successful supplier(s).

The deadline to submit your proposal(s) is **10:30 a.m. Mountain Daylight Time on November 16, 2016.** Please submit your proposal(s) to the attention of Trevor Mitchell, at the e-mail address provided below:

trevor.mitchell@enbridge.com

The successful supplier(s) of the above storage service(s) will be determined primarily on the basis of price and intra-day operational flexibility. Please note that successful suppliers must meet all Enbridge's credit criteria. Enbridge, in its sole discretion and for whatever reason, may accept or reject any and all proposals. Enbridge reserves the right at any time after the deadline to conduct negotiations with one or more of the bidders to the exclusion of others, and such negotiations may include changes to the described storage service in this RFP.

If you have any questions regarding this RFP, please do not hesitate to call me at 403 663-6622.

Yours truly,

Trevor Mitchell
Senior Specialist, Gas Supply and Asset Optimization
Enbridge Gas Distribution Inc.

BOMA INTERROGATORY #18

INTERROGATORY

Ref: Exhibit D1, Tab 2, Schedule 3, Page 3

Why the difference in contracted daily volume between the Forecast Peak Day Supply Mix and the Status of Transportation Contracts documents?

RESPONSE

As stated in Exhibit D1, Tab 2, Schedule 3, page 3 the difference is due to the fact that the Peak Day Supply Mix schedule (Exhibit D1, Tab 2, Schedule 7) displays volumes delivered to the Enbridge franchise area, while the Status of Transportation Contracts schedule (Exhibit D1, Tab 2, Schedule 9) lists all Transportation contracts, including those that deliver volume to other receipt points such as Dawn, for transportation onwards to the CDA and EDA.

For example, Line 20 on Exhibit D1, Tab 2, Schedule 9 (the Status of Transportation & Storage Contracts) displays capacity of 86,869 GJ on Nova Transmission. This capacity is not visible anywhere on Exhibit D1, Tab 2, Schedule 7 (the Peak Day Supply Mix) because the capacity does not flow directly into the franchise area. The Nova Transmission capacity is for transportation between Nova Inventory Transfer and the Empress hub on the border of Alberta and Saskatchewan. From Empress, Enbridge utilizes its various TransCanada Long Haul capacity (visible in Lines 1 to 6 in Exhibit D1, Tab 2, Schedule 9 or Item 4 in Exhibit D1, Tab2, Schedule 7) to transport the gas from Empress to the CDA and EDA.

The attached table provides the corresponding contract references from Exhibit D1, Tab 2, Schedule 9 and the various line items on Exhibit D1, Tab 2, Schedule 7.

Witness: D. Small

2017 Budget Peak Day Demand

Item #	GJ's	Column 4 CDA	Ex D1, T2, S9, page 1 Reference - Item #'s	Column 5 EDA	Ex D1, T2, S9, page 1 Reference - Item #'s	Column 6 Total
1.	Demand	3,360,682		697,973		4,058,655
2.	Less Curtailment	(78,012)		(34,897)		(112,909)
3.	Net Peak Day Demand	3,282,669		663,076		3,945,746
4.	TCPL FT Capacity	138,468	1 + 2	224,377	3 + 4 + 6	362,845
5.	TCPL STFT	-		-		-
6.	TCPL Short Haul	228,046	7 + 8 + 16	154,000	10 + 13	382,046
7.	TCPL STS	369,465	14 + 15 + 17	250,611	12 + 18 + 19	620,076
8.	Ontario T-Service	209,846		4,602		214,448
9.	Union Deliveries	2,175,027	28 to 35 + 37 + 38 Less Item # 7	-		2,175,027
10.	Delivered Service	132,738		-		132,738
11.	Peaking Service	29,080		29,486		58,565
12.	Total Supply	3,282,669		663,076		3,945,746
13.	Sufficency/(Deficiency)	-		-		-

Witness: D. Small

BOMA INTERROGATORY #19

INTERROGATORY

Ref: Exhibit D1, Tab 2, Schedule 5, Page 1; Exhibit D1, Tab 2, Schedule 8, Page 2

Summary of Gas Costs to Operations shows Dawn Supplies at 2,229,769.2. Gas Supply/Demand Balance shows Delivered Supplies of the same amount.

Please confirm or explain, in detail:

(a) All EGD's "delivered supplies" are delivered at Dawn.

(b) Please provide the total deliveries to EGD using the Dawn-Parkway Facilities, either by Union or by TCPL. Since Dawn is not a supply basin, what is the source(s) of the "Dawn Supplies" or "Delivered Supplies".

(c) Please confirm that the Chicago supplies and the Nexus supplies, while they flow through Dawn, are not part of the Delivered Supplies (Dawn Supplies) on these two tables. They are rather additive to whatever supplies are included in the term "Delivered Supplies". Please explain fully.

(d) Please provide the total amount (absolute and percentage of total gas supply) of EGD's forecast 2017 gas supply sales and bundled service, that will flow through Union's Dawn-Parkway facilities.

RESPONSE

a) In the referenced exhibits, both “Dawn Supplies” and “Delivered Supplies” refer to supply purchased by Enbridge at the Dawn Hub.

b) While Dawn may not be a supply basin it is considered a “Hub” where a liquid market exists for buyers and sellers. Enbridge has contracted for transportation services with both TCPL and Union – see Status of Transportation Contracts at Exhibit D1, Tab 2, Schedule 9 – which allows Enbridge to transport gas purchased at Dawn, delivered to Dawn via other transportation services such as Vector Pipeline, and storage withdrawal volumes to the CDA and to the EDA.

Total deliveries from Dawn to the CDA and EDA are discussed in part (d), below.

Witness: D. Small

c) Confirmed. The volumes identified as Chicago and Nexus supplies are independent from the amount identified as Dawn Supplies and are transported to Dawn using contracted Vector pipeline capacity.

d) As shown at Exhibit D1, Tab 2, Schedule 8, page 1, forecasted deliveries in 2017, including a net storage fluctuation of 16,098.1 10^3m^3, is 11,849,167.8 10^3m^3. The total volume flowing through Dawn, excluding any Direct Purchase deliveries, is 4,439,230.0 10^3m^3 or 37.4%. This total is the sum of Items 2.4, 2.5, 2.7, 2.8, and 2.10. That is, Chicago Supplies, Dawn Supplies, Link Supplies, Dominion Supplies, and the net storage fluctuation.

Witness: D. Small

BOMA INTERROGATORY #20

INTERROGATORY

Ref: Exhibit D1, Tab 2, Schedule 9

(a) Which of the contracts listed from A to I are with Union Gas, and which are provided by other suppliers, either Canadian or American?

(b) Please provide the names of each of the storage providers, other than Union Gas.

(c) Which supplies, and how much of the 24.5 PJs volume is supplied by storage sources in Michigan?

(d) What is the forecast average 2017 market price for storage from all nine contracts; what is the breakdown by month.

(e) Please provide details of any constraints on the use of Michigan based storage at any time during the year.

RESPONSE

a), b) and c)

Please see response to BOMA #15 at Exhibit I.D1.EGDI.BOMA.15. As stated, Enbridge is reluctant to provide the identities of storage counterparties, as this may impair Enbridge's competitive position when re-contracting.

d) Forecasted annual cost of third party storage can be found at Exhibit D1, Tab 2, Schedule 6, page 1, Column 1, Item 1.4.

e) Enbridge has not experienced any constraints pertaining to its contracted Michigan storage.

Witness: D. Small

ENERGY PROBE INTERROGATORY #8

INTERROGATORY

Reference: Exhibit D1, Tab 2, Schedule 4, Page 3, Figure 1

Preamble: Enbridge's unaccounted for gas volumes have been increasing over the last decade and, in recent years, have been higher than Board-approved volumes (nearly double in 2014).

a) Can Enbridge explain why unaccounted-for-gas volumes have been increasing?

b) Can Enbridge detail the impacts that increase has on the residential rate class?

RESPONSE

a) Enbridge has examined the elements that potentially contribute to unaccounted-for-gas volumes ("UAF") and they have not shown any marked variability. In addition, Enbridge has over the years, focused on various programs within its Operations and Engineering functions to ensure the safe and reliable operation of its infrastructure. Integrity and damage prevention programs have demonstrated improved metrics confirming the effectiveness of these efforts.

   As available, Enbridge compares its performance relative to other utilities in this area. Based on the last update from the American Gas Association in August 2015, Enbridge's UAF as a percentage of throughput is comparable with the average from 194 natural gas utilities.

b) The forecast unaccounted gas volumes are priced at the test year forecast PGVA reference price and the resulting cost forms part of the Company's gas cost to operations budget as found at Exhibit D1, Tab 2, Schedule 5. As part of the Company's Quarterly Rate Adjustment Mechanism ("QRAM"), the cost of the unaccounted for gas volumes is updated to reflect each quarter's proposed PGVA reference price. The cost of unaccounted for gas is recovered from all bundled customers and is allocated to the rate classes based on the bundled delivery volumes. The cost is recovered in the delivery component of customer's rates.

Witnesses: M. Kirk
D. Small
M. Suarez

ENERGY PROBE INTERROGATORY #9

INTERROGATORY

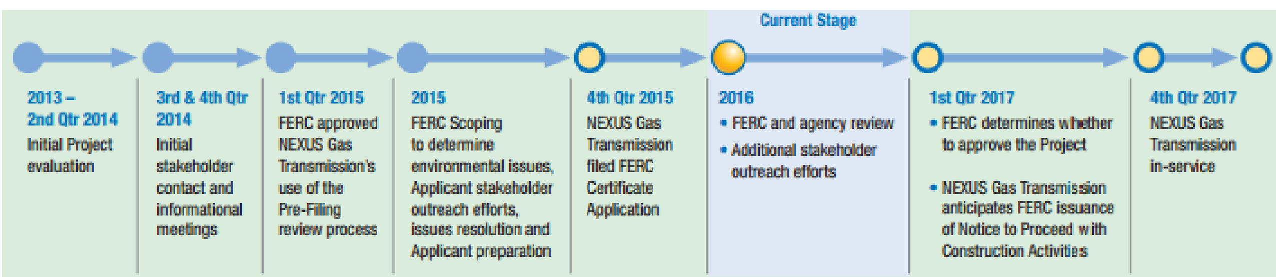
Reference: Exhibit D1, Tab 2, Schedule 11, Page 2

a) Does Enbridge have any updates on the Nexus project in regards to its schedule and cost? Please provide details

RESPONSE

Enbridge has not received any recent updates leading it to believe the Nexus project has altered its schedule or costs.

The Nexus website contains a community newsletter illustrating the current stage of the project. An excerpt of the project timeline from the latest newsletter is provided below.



Source: http://www.nexusgastransmission.com/content/informational-resources

Further information on the NEXUS project can also be found through the following link to the FERC website under docket number CP16-22:

http://elibrary.ferc.gov/idmws/docket_search.asp

Witnesses: M. Kirk
D. Small

ENERGY PROBE INTERROGATORY #10

INTERROGATORY

Reference: Exhibit D1, Tab 4, Schedule 1, Page 1

a) Please provide an updated figure on DSM spending to date for 2016?

b) Please Provide 2016 Q3 budget and spend by major sector

c) Please provide 2016 Scorecard Targets and Q3 achievements

RESPONSE

a), b, & c)

The review of estimated and or actual 2016 DSM related spending is not relevant to the Board approved amount of DSM activity and cost for 2017. The DSM activities and budget for 2017 were approved in the 2015-2020 Multi-Year DSM Plan proceeding (EB-2015-0049). Discussion and review of DSM activities is to occur within other Deferral & Variance account balance review proceedings or within any future intended review of DSM plans by the Board.

Witness: M. Lister

FRPO INTERROGATORY #3

INTERROGATORY

REF: Exhibit D1, Tab 2, Schedule 2, Page 11, Figure 3

Preamble: While respect that the graph is illustrative, we are interested in the assumptions that support the multi-peak approach in the context of recent changes to the storage targets especially during the month of March.

Please provide the data behind the graph and the source of data and assumptions that contribute to the graph.

a) If the graph is not based upon actual experience (illustrative), please provide the actual data, source and assumptions.

b) Please ensure that the data and derivation of the forecasted peaks for March are provided.

RESPONSE

a) The yellow line in the referenced graph is the daily demand profile Enbridge used in the preparation of its 2015 gas supply plan (i.e., August 1, 2014 to July 31, 2015). The profile is the result of the Company's Demand Profile process described at length in Section 2.3 of the referenced Gas Supply Memorandum.

b) The data is provided in Table 1, below. As stated, the derivation is described in Section 2.3 of the referenced Gas Supply Memorandum. The referenced section relies on evidence filed in EB-2011-0354, and is expanded below to aid in the understanding of the multi-peak approach.

> *Multi-peaks were developed for each of the Central, Eastern and Niagara regions of Enbridge's franchise area using temperature data from Environment Canada. The days within the months of January, February and March were divided into 5 day brackets. A peak was the developed for each 5 day bracket. Each 5 day bracket was then assigned one peak resulting in a total of 18 multi-peaks for each region respectively. A peak was then developed for each 15 day bracket within each month. A peak was also developed for each month. The peak for each 15 day bracket replaced the coldest peak in the three 5 day brackets contained with each 15 day bracket. The peak for the month replaced the coldest peak in the two 15 day brackets with the exception of January. The monthly peak*

Witnesses: M. Kirk
D. Small
A. Welburn

> *for January was replaced with the peak day HDD value. Within each 5 day bracket a multi-peak was placed on the day determined to be the coldest average day within that bracket. The peak day HDD value was placed on January 15, historically the coldest day on average in the winter. Additionally, January 15 was designed to occur on a week day. The rationale for imposing peak day HDD to occur during a week day arises from the observation that demand on weekdays is higher than demand on weekends, and therefore weekdays are more suitable for supply planning. Each of the 18 multi-peaks in the current Design Criteria correspond to a recurrence interval of 1 in 5 years and were derived assuming degree days are normally distributed.*

Subsequent to the filing of the above-noted evidence in EB-2011-0354, the Company proposed changes to its Design Criteria in EB-2011-0354 which resulted in recurrence interval being maintained at 1 in 5 years but the multi-peaks being derived assuming degree days are log-normally distributed. That approach was agreed to and approved in the EB-2011-0354 Settlement Agreement.

Witnesses: M. Kirk
D. Small
A. Welburn

Table 1

PJs		PJs		PJs		PJs		PJs		PJs	
1-Aug	0.3790	1-Sep	0.5168	1-Oct	0.7687	1-Nov	1.2268	1-Dec	1.8364	1-Jan	2.0425
2-Aug	0.3982	2-Sep	0.5146	2-Oct	0.7143	2-Nov	1.3495	2-Dec	1.8962	2-Jan	2.1289
3-Aug	0.3801	3-Sep	0.5232	3-Oct	0.6983	3-Nov	1.3901	3-Dec	1.8855	3-Jan	1.9474
4-Aug	0.4762	4-Sep	0.4442	4-Oct	0.7901	4-Nov	1.3987	4-Dec	1.8588	4-Jan	1.9720
5-Aug	0.4826	5-Sep	0.4057	5-Oct	0.9396	5-Nov	1.4318	5-Dec	1.7948	5-Jan	2.8304
6-Aug	0.4762	6-Sep	0.4431	6-Oct	0.8872	6-Nov	1.4350	6-Dec	1.8812	6-Jan	2.1300
7-Aug	0.3961	7-Sep	0.4079	7-Oct	0.8894	7-Nov	1.2972	7-Dec	2.0713	7-Jan	2.2443
8-Aug	0.3812	8-Sep	0.5328	8-Oct	0.8413	8-Nov	1.3218	8-Dec	2.0905	8-Jan	2.2293
9-Aug	0.4057	9-Sep	0.5306	9-Oct	0.8029	9-Nov	1.4403	9-Dec	1.9816	9-Jan	2.1631
10-Aug	0.4399	10-Sep	0.5381	10-Oct	0.7687	10-Nov	1.4777	10-Dec	2.0040	10-Jan	3.0397
11-Aug	0.4869	11-Sep	0.4612	11-Oct	0.8264	11-Nov	1.6101	11-Dec	2.0403	11-Jan	1.9581
12-Aug	0.4783	12-Sep	0.4057	12-Oct	0.7709	12-Nov	1.6026	12-Dec	1.9400	12-Jan	1.9378
13-Aug	0.4826	13-Sep	0.4591	13-Oct	0.9086	13-Nov	1.4723	13-Dec	1.9934	13-Jan	2.1076
14-Aug	0.3940	14-Sep	0.5007	14-Oct	0.9780	14-Nov	1.3239	14-Dec	1.9987	14-Jan	2.1834
15-Aug	0.3812	15-Sep	0.6043	15-Oct	1.0047	15-Nov	1.4221	15-Dec	1.9912	15-Jan	3.9776
16-Aug	0.4014	16-Sep	0.5904	16-Oct	0.8776	16-Nov	1.5759	16-Dec	2.0510	16-Jan	2.1471
17-Aug	0.4420	17-Sep	0.5830	17-Oct	0.8178	17-Nov	1.6581	17-Dec	2.1332	17-Jan	2.0329
18-Aug	0.4826	18-Sep	0.4794	18-Oct	0.8830	18-Nov	1.6261	18-Dec	2.0681	18-Jan	2.0660
19-Aug	0.4911	19-Sep	0.4249	19-Oct	1.0762	19-Nov	1.5428	19-Dec	2.0585	19-Jan	2.1973
20-Aug	0.4890	20-Sep	0.4975	20-Oct	1.0271	20-Nov	1.5599	20-Dec	2.0670	20-Jan	3.5479
21-Aug	0.4089	21-Sep	0.5232	21-Oct	1.1072	21-Nov	1.5172	21-Dec	1.9966	21-Jan	3.2041
22-Aug	0.3833	22-Sep	0.5990	22-Oct	1.1403	22-Nov	1.6004	22-Dec	1.9773	22-Jan	2.1652
23-Aug	0.4132	23-Sep	0.6278	23-Oct	0.9214	23-Nov	1.6367	23-Dec	1.9656	23-Jan	2.0190
24-Aug	0.4474	24-Sep	0.6321	24-Oct	0.8637	24-Nov	1.7649	24-Dec	2.0788	24-Jan	2.0681
25-Aug	0.4837	25-Sep	0.5285	25-Oct	0.9246	25-Nov	1.6827	25-Dec	2.0884	25-Jan	2.1983
26-Aug	0.4783	26-Sep	0.4377	26-Oct	1.0570	26-Nov	1.6816	26-Dec	2.1834	26-Jan	3.2009
27-Aug	0.4879	27-Sep	0.5253	27-Oct	1.0773	27-Nov	1.5407	27-Dec	2.0361	27-Jan	2.2923
28-Aug	0.4132	28-Sep	0.5637	28-Oct	1.1723	28-Nov	1.5289	28-Dec	1.9400	28-Jan	2.2571
29-Aug	0.3886	29-Sep	0.6801	29-Oct	1.2011	29-Nov	1.5823	29-Dec	2.0521	29-Jan	2.2400
30-Aug	0.4175	30-Sep	0.6577	30-Oct	0.9748	30-Nov	1.6698	30-Dec	2.1012	30-Jan	2.1460
31-Aug	0.4538			31-Oct	0.9001			31-Dec	1.9976	31-Jan	2.0713

PJs		PJs		PJs		PJs		PJs		PJs	
1-Feb	1.9901	1-Mar	1.7958	1-Apr	1.4584	1-May	0.7079	1-Jun	0.5285	1-Jul	0.3897
2-Feb	2.0489	2-Mar	1.9720	2-Apr	1.4510	2-May	0.6556	2-Jun	0.5883	2-Jul	0.4826
3-Feb	2.0905	3-Mar	2.6500	3-Apr	1.2321	3-May	0.7036	3-Jun	0.6118	3-Jul	0.4014
4-Feb	3.2767	4-Mar	1.9464	4-Apr	1.2139	4-May	0.7623	4-Jun	0.5851	4-Jul	0.3876
5-Feb	2.3895	5-Mar	1.9485	5-Apr	1.2236	5-May	0.7634	5-Jun	0.4975	5-Jul	0.4100
6-Feb	2.9180	6-Mar	1.8652	6-Apr	1.4339	6-May	0.7783	6-Jun	0.4303	6-Jul	0.4452
7-Feb	2.0766	7-Mar	2.5208	7-Apr	1.4713	7-May	0.7890	7-Jun	0.4740	7-Jul	0.4879
8-Feb	2.1343	8-Mar	1.7414	8-Apr	1.4350	8-May	0.6684	8-Jun	0.5082	8-Jul	0.4847
9-Feb	2.1845	9-Mar	2.0019	9-Apr	1.4520	9-May	0.6022	9-Jun	0.5605	9-Jul	0.4826
10-Feb	2.2880	10-Mar	1.8481	10-Apr	1.1403	10-May	0.6908	10-Jun	0.5552	10-Jul	0.3972
11-Feb	3.0706	11-Mar	2.4268	11-Apr	1.1232	11-May	0.7388	11-Jun	0.5434	11-Jul	0.3854
12-Feb	2.3361	12-Mar	1.9816	12-Apr	1.1392	12-May	0.7879	12-Jun	0.4527	12-Jul	0.4057
13-Feb	2.1407	13-Mar	1.7040	13-Apr	1.3442	13-May	0.7730	13-Jun	0.4185	13-Jul	0.4410
14-Feb	2.0286	14-Mar	1.5609	14-Apr	1.2257	14-May	0.7463	14-Jun	0.4506	14-Jul	0.4826
15-Feb	2.0595	15-Mar	1.6666	15-Apr	1.1670	15-May	0.6470	15-Jun	0.4890	15-Jul	0.4783
16-Feb	3.1518	16-Mar	1.7884	16-Apr	1.2332	16-May	0.6054	16-Jun	0.5434	16-Jul	0.4783
17-Feb	2.0553	17-Mar	1.7457	17-Apr	1.0944	17-May	0.6929	17-Jun	0.5424	17-Jul	0.3929
18-Feb	1.9677	18-Mar	1.7275	18-Apr	0.9620	18-May	0.6128	18-Jun	0.5328	18-Jul	0.3865
19-Feb	1.8855	19-Mar	1.6923	19-Apr	0.9470	19-May	0.7324	19-Jun	0.4506	19-Jul	0.4057
20-Feb	1.8001	20-Mar	2.4001	20-Apr	1.1616	20-May	0.7282	20-Jun	0.4196	20-Jul	0.4399
21-Feb	1.8129	21-Mar	2.2197	21-Apr	1.1776	21-May	0.7314	21-Jun	0.4410	21-Jul	0.4869
22-Feb	1.8866	22-Mar	1.6367	22-Apr	1.2118	22-May	0.6150	22-Jun	0.4847	22-Jul	0.4847
23-Feb	2.0628	23-Mar	1.6688	23-Apr	1.1478	23-May	0.5744	23-Jun	0.5264	23-Jul	0.4815
24-Feb	2.9148	24-Mar	1.6549	24-Apr	0.9652	24-May	0.6844	24-Jun	0.5360	24-Jul	0.3929
25-Feb	2.1375	25-Mar	1.5663	25-Apr	0.8894	25-May	0.6854	25-Jun	0.5296	25-Jul	0.3854
26-Feb	2.0307	26-Mar	2.2432	26-Apr	0.9225	26-May	0.7153	26-Jun	0.4292	26-Jul	0.4036
27-Feb	2.6265	27-Mar	1.4264	27-Apr	1.1285	27-May	0.6961	27-Jun	0.4111	27-Jul	0.4420
28-Feb	1.8407	28-Mar	1.2225	28-Apr	1.1307	28-May	0.6887	28-Jun	0.4410	28-Jul	0.4815
		29-Mar	1.3058	29-Apr	0.9961	29-May	0.5894	29-Jun	0.4826	29-Jul	0.4794
		30-Mar	1.4125	30-Apr	0.9556	30-May	0.5531	30-Jun	0.5253	30-Jul	0.4783
		31-Mar	1.4232			31-May	0.6769			31-Jul	0.4004

Witnesses: M. Kirk
D. Small
A. Welburn

FRPO INTERROGATORY #4

INTERROGATORY

REF: Exhibit D1. Tab 2, Schedule 2, Page 18

We are interested in understanding the genesis of the Link Supplies in the Enbridge portfolio.

How was the benefit of Michigan supplied gas deemed to be better than regular discretionary purchases at Dawn?

a) Describe how the annual contract was obtained, i.e. unsolicited offer, RFP, unique opportunity, one year trial basis, etc.?

b) If by RFP, please provide the RFP associated with the acquisition.

RESPONSE

The Company's 2017 gas supply plan includes a 2,230 10^6m^3 supply requirement at Dawn[1] which is over twice as large as the 1,052 10^6m^3 supply requirement at Dawn that was identified in its 2016 gas supply plan[2]. Given the magnitude of the Dawn supply requirement for 2017, the Company entered into negotiations with a market participant that included an exchange of supply from MichCon to Corunna combined with transportation capacity on the Link pipeline that would transport supply from Corunna to Tecumseh in the summer season (April to October) and to Dawn in the winter season (November to March). This arrangement enabled the Company to diversify its supply requirement at Dawn in a cost effective manner that was consistent with its gas supply planning principles. The landed cost analysis underpinning this decision is provided in response to TCPL Interrogatory #1 at Exhibit I.D1.EGDI.TCPL.1.

The Company did not issue an RFP given the unique nature of the supply arrangement.

[1] EB-2016-0215, Exhibit D1, Tab 2, Schedule 5, Page 1 of 2
[2] EB-2015-0114, Exhibit D1, Tab 2, Schedule 4, Page 1 of 2

Witnesses: M. Kirk
D. Small

FRPO INTERROGATORY #5

INTERROGATORY

REF: Exhibit D1. Tab 2, Schedule 2, Page 24
And
EB-2016-0142 Exhibit I.D.EGDI.FRPO.23

Preamble: We are interested in understanding better Enbridge process in arriving at the choice of Synthetic Storage to meet winter balancing needs.

Please provide the ICF study that was completed as a result of the March 11, 2016 RFP.

a) Please provide a summarized output table from SENDOUT demonstrating that, given a constant set of forecast assumptions, it is preferable to purchase synthetic storage instead of a set of winter purchases at Dawn for the same quantity of winter gas.

b) Please provide any compelling reasons or other considerations which would inhibit the disciplined acquisition of winter gas as part of a risk-managed portfolio.

RESPONSE

The Company is not able to provide the referenced study as it has not yet been completed. As was agreed to in the EB-2016-0142 Settlement Agreement, the Company has committed "that before the Company develops or acquires additional storage capacity for utility or regulated gas supply purposes it will file analysis with the Board setting out the need and justification for the incremental storage"[1]. The analysis is expected to include any related ICF study.

a) As discussed in response to Exhibit I.D.EGDI.FRPO.23 page 2 in EB-2016-0142, the Company ran a scenario whereby "allowing SENDOUT to manage the increased demand during the winter through incremental storage as discussed above, SENDOUT was permitted to procure additional natural gas supply at Dawn in the winter."
The purpose of this evaluation was to determine the incremental storage capacity requirement and it did not consider if any incremental storage capacity would be facilitated through physical or synthetic contracts. Further, SENDOUT cannot differentiate between physical and synthetic storage attributes, other than costs.

[1] 2015 Earning Sharing Mechanism and Other Deferral and Variance Account Clearing Review Settlement Proposal, EB-2016-0142, Exhibit N1, Tab 1, Schedule 1, Page 15 of 22

Witnesses: M. Kirk
D. Small
A. Welburn

As a result, the Company does not have the SENDOUT data that has been requested.

b) The Company assumes this question relates to procuring gas during the winter as a substitute for utilizing synthetic storage. Synthetic storage has been utilized by the Company for many years as an alternative to physical storage. There is nothing preventing the Company from procuring gas in the winter at Dawn. However, pricing is typically higher in the winter and lower in the summer (i.e., gas prices exhibit seasonal spreads). Consequently, straight acquisition of gas during the winter would expose ratepayers to a greater degree of price risk and potential price volatility. This could be particularly pronounced should winter pricing conditions similar to those experienced in the winter of 2013 / 2014 occur again.

Witnesses: M. Kirk
D. Small
A. Welburn

FRPO INTERROGATORY #6

INTERROGATORY

REF: Exhibit D1, Tab 2, Schedule 3, Page 5

Preamble: We are interested in understanding more about the elimination of UDC.

Please confirm that any potential UDC from pipeline over-deliveries would instead be handled by varying the level of Dawn discretionary purchases.

a) If not confirmed, please explain how risks of under-consumption relative to forecast will be managed.

RESPONSE

Confirmed.

The 2017 forecast assumes 100% utilization of Enbridge's contract long haul FT capacity with TCPL and therefore has not forecasted any UDC cost for 2017.

As described at Exhibit D1, Tab 2, Schedule 3, page 5, paragraph 14, the Company has forecast an additional seasonal requirement at Dawn. To offset a small portion of that requirement the Company contracted for an increment 50,000 MMBTU/day of Vector capacity for the December 1, 2016 to February 28, 2017 period as well as a one year contract for 40,000 MMBTU/day of Link capacity effective November 1, 2016. A portion of the forecast 2017 Dawn requirement remains uncontracted and the Company plans to take a measured approach through acquiring that supply through seasonal or monthly RFPs in conjunction with daily purchases dependent upon short and medium term weather and demand forecasts. Should demand come in lower than budget, Enbridge will reduce planned purchases at Dawn. This approach is described in the Execution section (Section 2.5) of the Gas Supply Memorandum at Exhibit D1, Tab 2, Schedule 2, page 14.

Witness: D. Small

FRPO INTERROGATORY #7

INTERROGATORY

REF: Exhibit D1, Tab 2, Schedule 3, Page 5

Preamble: We are interested in understanding more about the elimination of UDC.

Please confirm any additional consequences including the risk of leaving some pipeline capacity empty will be absorbed by the company's shareholder.

a) If not confirmed, please describe Enbridge's proposed handling of such an occurrence.

RESPONSE

As discussed in the response to FRPO Interrogatory #6 at Exhibit I.D1.EGDI.FRPO.6, the Company intends to manage its forecasted Dawn requirement and to contract for supplies such that if actual demand in 2017 is less than forecast the Company will not incur any UDC on its contracted long haul TCPL FT capacity. If changes in circumstances led to some empty long haul TCPL FT capacity, the Company's handling of that occurrence would depend on the circumstances.

Witness: D. Small

FRPO INTERROGATORY #8

INTERROGATORY

REF: Exhibit D1, Tab 2, Schedule 3, Page 5-6 & Tab 2, Schedule 11, Page 4
and
EB-2014-0323 Transcript Enbridge Gas Dawn Access, Volume 1 pages 10-14

Preamble: The Dawn Access Consultative created a settlement that recognized that the transfer of delivery point obligations would be dependent upon a number of factors and conditions and that Enbridge committed to continuing to consult to ensure an appropriate transition. We would like to understand more about Enbridge's plans for continued consultation and its views on the potential for direct purchase customers to move their supply to Dawn at the earliest opportunity.

Has Enbridge initiated any formal or informal consultation on the potential of allowing other delivery points in Ontario?

a) If not, what is Enbridge's intent moving forward to assess interest and capability to provide additional delivery point options.

b) If yes, when did this happen and what happened?

RESPONSE

a) and b)

Enbridge has not initiated any formal or informal consultation relating to the possibility of allowing other delivery points in Ontario. A majority of the direct purchase customers that elected Dawn as their delivery point have made a minimum one year commitment. This does not leave any significant remaining level of demand for any other delivery point including a new point. The criteria specified in the Dawn Access Settlement Agreement for consideration of any other delivery point are set out at pages 12 to 13 (EB-2014-0323, Exhibit B, Tab 2, Schedule 1, pages 12 to 13) and are reproduced below.

> In addition, Enbridge will modify its business systems in a manner that will accommodate future market access to additional transportation services from liquid market hubs. Enbridge will remain in communication with customers about the demand for additional transportation services and, if demand emerges for at least 50,000 GJ/day of transportation service16 from an additional liquid market hub, Enbridge will respond by consulting with market participants about the implementation of such a transportation service.

Witnesses: R. DiMaria
D. Small
A. Welburn

Enbridge further notes that within a separate communication/agreement with FRPO (see letter dated November 19, 2014 from Ian MacPherson (Enbridge) to Kirsten Walli (OEB Secretary), filed in the EB-2014-0323 proceeding), it was agreed that Enbridge would first initiate consultations for defining the criteria that must be met before establishing a transportation service from receipt points other than those currently offered. To date, other than in the context of questions from FRPO, Enbridge has not received any additional interest in the possibility of establishing other delivery points. However, the Company will look to commence a survey in 2017 to gauge additional interest and then determine when consultations would be best undertaken for defining criteria that must be met before Enbridge would establish a transportation service from newly emerging direct purchase delivery points.

Witnesses: R. DiMaria
D. Small
A. Welburn

FRPO INTERROGATORY #9

INTERROGATORY

REF: Exhibit D1, Tab 2, Schedule 3, Page 5-6 & Tab 2, Schedule 11, Page 4
and
EB-2014-0323 Transcript Enbridge Gas Dawn Access, Volume 1 pages 10-14

Preamble: The Dawn Access Consultative created a settlement that recognized that the transfer of delivery point obligations would be dependent upon a number of factors and conditions and that Enbridge committed to continuing to consult to ensure an appropriate transition. We would like to understand more about Enbridge's plans for continued consultation and its views on the potential for direct purchase customers to move their supply to Dawn at the earliest opportunity.

Enbridge communicated that there were some Preconditions that would need to be met to allow for Phase 2 to be completed. Please provide an update on the status of the IT systems changes approved by the Board in EB-2014-0323 including:

a) status with major milestones

b) projected completion of the major milestones including any testing performed in conjunction with direct purchase customers.

c) costs incurred to this point and projected final costs

RESPONSE

a) A listing of status updates and major project Milestones is provided below:

Completed Milestones:
- Detailed Requirements
- Development
- Master Test Plan
- Integration Testing
- Performance Testing

In Progress:
- System Integration Testing ("SIT") including E2E test & Regression
- Cutover planning

Witness: R. DiMaria

Next Milestones:

- Market Participant test plan - November 27, 2016
- SIT Completion – December 5, 2016
- UAT kick off including E2E test & Regression - January 2, 2017
- Cutover Plan – January 15, 2017
- UAT Completion – April 28, 2017
- Cutover/implementation – May 15, 2017

b) The Company anticipates system changes to be completed by May 2017. These changes will be inclusive of market testing and heat value conversion modifications.

c) As of October 31, 2016, costs incurred are approximately $3 million. Final project costs are estimated to be approximately $6 million.

Witness: R. DiMaria

FRPO INTERROGATORY #10

INTERROGATORY

REF: Exhibit D1, Tab 2, Schedule 3, Page 5-6 & Tab 2, Schedule 11, Page 4
and
EB-2014-0323 Transcript Enbridge Gas Dawn Access, Volume 1 pages 10-14

Preamble: The Dawn Access Consultative created a settlement that recognized that the transfer of delivery point obligations would be dependent upon a number of factors and conditions and that Enbridge committed to continuing to consult to ensure an appropriate transition. We would like to understand more about Enbridge's plans for continued consultation and its views on the potential for direct purchase customers to move their supply to Dawn at the earliest opportunity.

Enbridge negotiated an agreement with TCPL that long haul contract delivery would stay in place until the completion of the Vaughan Loop in the event that there is a delay in the completion of that project beyond Nov. 1, 2017.

a) With the completion of King's North, TCPL Maple Compressor and Segments A and B of the GTA project, what are the potential risks of allowing direct purchase customers to transfer their delivery location prior to Nov. 1, 2017 (i.e., during the summer of 2017)?

b) If Enbridge believes these risks are insurmountable, would Enbridge consider extending the renewal date of direct purchase customers' contracts that expire between April 1 and October 31 to a renewal date of Nov. 1 to allow migration of contractually obligated deliveries to Dawn at that point?

c) Alternatively, as direct purchase customers renew starting April 1, 2017, would Enbridge consider allowing migration of contractually obligated deliveries to Dawn on their 2017 anniversary date?

RESPONSE

a), b, and c)

The Dawn Access Settlement Agreement (EB-2014-0323, Exhibit B, Tab 2, Schedule 1) sets out a complete settlement by all parties. The Dawn Access Settlement Agreement was approved by the Board on November 20, 2014 (1Tr.17).

Witnesses: R. DiMaria
D. Small
A. Welburn

The Dawn Access Settlement Agreement clearly sets out the preconditions to and agreed-upon implementation timing for “Phase 2” (the Dawn Transportation Service).

As set out in the Dawn Access Settlement Agreement, the earliest date for implementation of Phase 2 is November 1, 2017. Achievement of that date requires that Enbridge’s system changes be in place, and all necessary Downstream Infrastructure must be in service – if those conditions are not met, the implementation date will be delayed. All parties agreed that for Phase 2 Eligible Customers that elect to change their Transportation Services, the change will be effective on the later of, November 1, 2017 (subject to the Phase 2 Preconditions and the Transition) or their current pool renewal date (Settlement Agreement, section 2.2.7).

Enbridge is not prepared to re-open the Dawn Access Settlement Agreement, and allow for earlier implementation of Phase 2, even if all the conditions are met before that date (which is a current unknown).

Witnesses: R. DiMaria
D. Small
A. Welburn

FRPO INTERROGATORY #11

INTERROGATORY

REF: Exhibit D1, Tab 2, Schedule 5, page 2, line 18
and
EB-2010-0231 Dec.& Order EGDI System Reliability Settlement, Ex. C, Tab 1, Sch.1, pg. 14-15

Preamble: We would like to understand better the continuation of Western supply for the winter of 2017/18.

After the expected conversion from long-haul to short-haul and second phase of Dawn Access is implemented scheduled for November 2017, how many GJ's of Western Bundled-T Service will EGD be relying upon?

a) How much will be allocated to direct purchase continuing with Western Bundled-T service?

b) Given the additional capacity that will come into service scheduled for November 1, 2017, please provide Enbridge's view on these evolutions representing a "Material Change in Circumstances" warranting a review and reporting by Enbridge and a consultation with its affected stakeholders.

RESPONSE

Preamble: The 2017 forecast assumed that during 2017 there would be a continued migration of Western T-service customers back to sales service such that prior to November 1, 2017 there would be approximately 140,000 GJ/day being delivered to Enbridge at Empress on behalf of Western T- Service customers.

a) As Direct Purchase agreements renew for November 1, 2017 and onward, customers will have the opportunity to convert their pool to the Dawn T-service option. The 2017 forecast assumed a conversion from Western T to Dawn T on November 1, 2017 of approximately 20,000 GJ/day and another 15,000 GJ/day December 1, 2017. The result is that as of December 1, 2017, approximately 105,000 GJ/day will be delivered to Enbridge at Empress on behalf of Western T-service customers (that volume will be allocated to Direct Purchase customers continuing with Western Bundled T-service).

Witness: D. Small

b) Enbridge does not consider that there is a "Material Change in Circumstances" that warrants a review and reporting of the implications of the change on system reliability and/or the Long Term Resolution agreed in the System Reliability proceeding.

Enbridge notes that there has been substantial and ongoing review of changes in the circumstances of the Ontario natural gas market over the past number of years, and that there has not been any issue raised about re-examining the items resolved in the System Reliability proceeding. Examples of recent proceedings which have addressed changes to and evolution of the Ontario natural gas market include the Dawn Access Consultative (EB-2014-0323); the GTA Pipeline Project (EB-2012-0451); the Long Term Contract Approval i.e., Nexus Pipeline contract (EB-2015-0175); the 2014 Natural Gas Market Review (EB-2014-0289); the 2015 Natural Gas Market Review (EB-2015-0237); and presentations and discussions at Enbridge stakeholder days.

Witness: D. Small

FRPO INTERROGATORY #12

INTERROGATORY

REF: Exhibit D1, Tab 2, Schedule 6

Preamble: Schedule 6 provides the components of transportation to meet Enbridge's peak day requirements in the respective CDA and EDA areas. We would like to understand better Enbridge's contracting practice in securing system gas supply through delivered services.

When Enbridge contracts for delivered supply, does Enbridge require the successful supplier to demonstrate the supply is underpinned by firm transport?

RESPONSE

Enbridge's preference when contracting for delivered services and peaking supplies is for the supply to be underpinned by firm transport or as an alternative to have the transport assigned to Enbridge.

An example of an RFP for Peaking Service which stipulates that Enbridge is looking for firm deliveries into either the CDA or EDA is attached. The expectation would be that counterparties responding to the RFP will comply with the terms of reference.

Witness: D. Small

Enbridge Gas Distribution Inc.
3000 Fifth Avenue Place
425 – 1st Street S.W.
Calgary, AB T2P 3L8
Canada
www.enbridge.com

Trevor Mitchell
Senior Specialist Asset Opt, Gas Supply
Enbridge Gas Distribution Inc.
Tel: 403 663 6622
Fax: 403 231 5770
trevor.mitchell@enbridge.com

ENBRIDGE

October 14, 2015

Dear Sir/Ms:

Subject: RFP - 10-day Peaking Supply at Enbridge CDA and/or Enbridge EDA for December 1, 2015 – March 31, 2016

Enbridge Gas Distribution Inc. (Enbridge) requires firm 10-day natural gas peaking supply delivered at the Enbridge CDA delivery area for the term of December 1, 2015 through March 31, 2016. Enbridge also requires firm 10-day natural gas peaking supply delivered at the Enbridge EDA delivery area for the term of December 1, 2015 through March 31, 2016.

Should you be interested in supplying this gas requirement to Enbridge, please submit a proposal stating the delivery location, the maximum daily volume and the relevant pricing terms (demand and commodity charges). With respect to commodity charges, a differential to Iroquois or Dawn Daily Index is preferred, but other pricing structures will be considered.

Please submit your proposal no later than **10:30 AM MDT on Wednesday, October 21, 2015** to the attention of Trevor Mitchell at the e-mail address and/or fax number provided below:

Ph: 403.663.6622
Fax: 403.231.5770
Trevor.Mitchell@enbridge.com

The successful supplier(s) of the above natural gas requirements will be determined primarily on the basis of lowest cost; however, Enbridge may elect not to accept any proposals. Enbridge reserves the right at any time after the deadline to conduct negotiations with one or more of the bidders to the exclusion of others, and such negotiations may include changes to the described peaking supply terms and conditions in this RFP to accommodate Dodd Frank Act provisions (if applicable).

If you have any questions regarding this RFP, please do not hesitate to call me.

Yours truly,

Trevor Mitchell
Enbridge Gas Distribution Inc.

FRPO INTERROGATORY #13

INTERROGATORY

REF: Exhibit D1, Tab 2, Schedule 6

Preamble: Schedule 6 provides the components of transportation to meet Enbridge's peak day requirements in the respective CDA and EDA areas. We would like to understand better Enbridge's contracting practice in securing system gas supply through delivered services.

Does Enbridge require the supplier to assign that transport to the company?

RESPONSE

Please see response to FRPO #12 at Exhibit I.D1.EGDI.FRPO.12.

Witness: D. Small

FRPO INTERROGATORY #14

INTERROGATORY

REF: Exhibit D1, Tab 2, Schedule 7

Preamble: In the context of the number of significant improvements in diversity of supply and distribution reinforcement, we are interested in the continued need for peaking supplies.

Recognizing this inquiry touches on commercially sensitive information and not expecting inappropriate disclosure, please provide the following information:

a) Location(s)
b) Quantity(s)
c) Term(s)
d) Number of calls available(S)
e) Cost of the service(s)

RESPONSE

In response to FRPO Interrogatory #12 at Exhibit I.D1.EGDI.FRPO.12, the Company provided a copy of the RFP that was sent to potential peaking suppliers for the winter of 2015/16. Within that RFP, Enbridge describes how it is looking for delivery to the CDA and to the EDA for the December 1, 2015 to March 31, 2016 period and that the Company would require 10 days of service.

For the 2016/17 winter the Company has issued an RFP with similar conditions related to location, term and number of calls. Upon reviewing the responses Enbridge has accepted offers totaling the requirement identified as part of its forecasted peak day design requirement. Enbridge is not prepared to disclose the specific prices paid under individual peaking arrangements because of commercial sensitivity. As stated in response to Board Staff Interrogatory #10 at Exhibit I.D1.EGDI.STAFF.10, the peaking contract pricing (in the aggregate) will be incorporated into gas costs as part of the derivation of the January 1, 2017 QRAM Reference Price.

Witness: D. Small

FRPO INTERROGATORY #15

INTERROGATORY

REF: Exhibit D1, Tab 2, Schedule 7

Preamble: In the context of the number of significant improvements in diversity of supply and distribution reinforcement, we are interested in the continued need for peaking supplies.

How is this need driven or increased by shift in direct purchase deliveries? Please provide a specific explanation with respect to increased short-haul in addition to the long-haul to short-haul conversion on TCPL.

RESPONSE

The attached table is a variation of Exhibit D1, Tab 2, Schedule 7, page 1 and provides a comparison 2016 vs 2017 peak day for the CDA and the EDA to better demonstrate the changes year over year.

As can be seen, the only conversion of long haul capacity to short haul capacity impacting 2017 was in the EDA where 166,000 GJ/day of Empress to EDA capacity was converted to 170,000 of Parkway to EDA capacity upon the in service date of the TCPL King's North project. Despite the slight increase in available transport it was not sufficient to offset the forecasted increase in EDA peak Day Demand of 12,202 GJ's leading to a slight increase in the peak day requirement in the EDA for 2017 versus 2016.

The impact of a change in forecasted Direct Purchase deliveries can be seen in the 2016 versus 2017 peak day demand comparison in the CDA. The 2017 forecast assumes a lower level of Direct Purchase deliveries primarily due to customers returning to sales service. As a consequence, Enbridge needed to acquire an additional 21,268 GJ's. This, coupled with an overall increase in the peak day demand requirement in the CDA in 2017 versus 2016 of 47,976 GJ's, resulted in an overall increased requirement of approximately 69,000 GJ's. Given that there was a supply sufficiency in 2016 of approximately 39,000 GJ's, this left the Company in the position of requiring approximately 30,000 GJ's of peaking service in the CDA in 2017.

Witness: D. Small

		2016 Budget Peak Day Demand - as filed in EB-2015-0114	2017 Budget Peak Day Demand	2017 vs 2016	2016 Budget Peak Day Demand - as filed in EB-2015-0114	2017 Budget Peak Day Demand	2017 vs 2016
		Column 1	Column 2	Column 3	Column 1	Column 2	Column 3
Item #	GJ's	CDA	CDA	CDA	EDA	EDA	EDA
1.	Demand	3,321,901	3,360,682	38,780	686,930	697,973	11,043
2.	Less Curtailment	(87,208)	(78,012)	9,195	(36,056)	(34,897)	1,159
3.	Net Peak Day Demand	3,234,694	3,282,669	47,976	650,875	663,076	12,202
4.	TCPL FT Capacity	138,468	138,468	(0)	390,377	224,377	(166,000)
5.	TCPL STFT	-	-	-	-	-	-
6.	TCPL Short Haul	226,840	228,046	1,206	154,000	154,000	-
7.	TCPL STS	369,465	369,465	-	80,611	250,611	170,000
8.	Ontario T-Service	231,114	209,846	(21,268)	5,417	4,602	(815)
9.	Union Deliveries	2,175,027	2,175,027	-	-	-	-
10.	Delivered Service	132,738	132,738	-	-	-	-
11.	Peaking Service	-	29,080	29,080	20,469	29,486	9,017
12.	Total Supply	3,273,653	3,282,669	9,017	650,875	663,076	12,202
13.	Sufficency/(Deficiency)	38,959	-	(38,959)	-	-	(0)

note (1) - assuming all Ontario T-Service customers migrate to Dawn T-Service.

Witness: D. Small

FRPO INTERROGATORY #16

INTERROGATORY

REF: Exhibit D1, Tab 2, Schedule 11, Page 11

Preamble: Paragraph 36 includes the sentence: "The Company is in the process of investigating whether or not there needs to be a change to the heat value conversion factor used in the budgeting process and will indicate its plans in due course."

We would like to understand more about the status of this investigation not only on the impact to the budgeting process, but also, the impact on direct purchase customers and system gas customers.

Please provide a simple summary of the issue being investigated.

RESPONSE

For the purposes of preparing its Gas Supply Plan and for calculating the daily delivery obligations of its Direct Purchase customers, Enbridge has used a standard conversion factor of 37.69 MJ/m^3 for a number of years. While this standard conversion factor has been generally satisfactory over the period of its use, the heat value has begun to rise recently bringing into question whether or not there should be a change in use of an estimated heat value.

As Table 1 attached shows, the average annual heat values for the years 2001 to 2011 have ranged from 37.36 MJ/m^3 in 2006 to 37.73 MJ/m^3 in 2011; however, in 2015 the average was 38.37 MJ/m^3.

While the average annual heat value for the years 2001 to 2015 is 37.71 MJ/m^3, the Company, as well as others, is concerned given the increases of late and the continuation thereof and of the potential costing impacts with respect to gas supply planning should a methodology not be put in place to make a change going forward not only for gas supply planning purposes but also for the establishment of daily deliveries for Direct Purchase customers.

Enbridge has reviewed the high level impacts of making a change to the heat value used for the purposes of gas cost budgeting and for determining deliveries for Direct Purchase customers using the volumetric forecast for the 2014, 2015, and 2016 budget volume forecasts.

Witnesses: R. DiMaria
D. Small

As set out in the attached Table 2, Enbridge has compared the impact on the budget years in question of using the standard conversion of 37.69 MJ/m^3 versus the actual annual average heat value for a particular year. For the purpose of this exercise, Enbridge used the annual budget volumes as filed less Company Use, UUF, LUF and unbilled volumes. The annualized impact assumed no storage fluctuation and for costing purposes used the October 2016 QRAM Reference Price. Also, for this exercise, no attempt was made to monetize the impact of any changes in Peak Day Design Demand because of a change in heat value.

Table 2 shows that if the 2015 Gas Cost Budget was prepared assuming the average heat content for 2015 of 38.37 MJ/m^3, the overall supply requirement would have increased by 7.5 TJ's (Column 4, Item #8). This increase would have been satisfied by incremental purchases by the Utility of 4.9 TJ's at a cost of $23.9 million and additional deliveries by the Direct Purchase customer of 2.6 TJ's at a cost to them of $12.5 million.

Assuming no change to the budgeted requirements (forecast volumes), the increase in purchases by the Company (i.e., the 4.9 TJ's) would translate into $23.9 million being recovered through the PGVA account in accordance with the Board-approved cost allocation and rate design methodology.

Further, assuming no changes were made to the Direct Purchase deliveries (MDV), the Company would have had to acquire the incremental 2.6 TJ's resulting in another $12.5 million being booked to the PGVA for disposition. The disposition of the PGVA would be in accordance with the Board approved cost allocation and rate design methodology.

In order to assess whether looking at one year in isolation is instructive, Enbridge also looked at other years.

As seen in Table 2, if the same calculations were done for 2014 as detailed above for 2015, the impact of the Utility to acquire the additional volume in lieu of deliveries from Direct Purchase customers would be lower - i.e., $8.2 million (Column 5, at Items 10 and 11) - because the average heat value in 2014 was lower than that for 2015 at an average of 38.14 MJ/m^3. Similarly, the amount of additional supply to meet the Utility's requirements would also be lower than in 2015.

Taking all of this into account, the Company believes it is appropriate to change the heat value going forward.

The Company intends to make a number of changes.

First, for purposes of the development of its gas supply plan, the Company intends to use an updated heat value in the derivation of its volume forecast effective with the 2018 forecast year.

Witnesses: R. DiMaria
D. Small

When the budget is to be prepared i.e., summer of 2017, the Company will calculate the average of the previous 12 months actual heat values and use that as the conversion factor replacing 37.69 MJ/m^3.

The updated heat value will be communicated to Direct Purchase customers and effective November 1, 2017, as Direct Purchase agreements renew, individual “pool deliveries” will be based upon that posted heat value.

The same process would apply with respect to the 2019 forecast year – a new heat value is calculated in the summer of 2018 to be used in gas supply planning and Direct Purchase contracting effective November 1, 2018.

There will also be a change with respect to Banked Gas Account (“BGA”) reporting. Currently, monthly Direct Purchase deliveries are converted from GJ’s to m^3 using the standard conversion factor of 37.69 MJ/m^3. Effective November 1, 2017, monthly Direct Purchase deliveries will be converted from GJ’s to m^3 based upon the actual average heat value for the month which will be a better representation of the actual consumption of the customers in that particular “pool”.

The initiative with respect to the establishment of daily Direct Purchase deliveries based on a new heat value and changes to BGA reporting will be implemented effective November 1, 2017. There are two reasons for this timing.

First, each of these initiatives require changes to be made to EnTRAC and the Company believes these changes can be accommodated with system enhancements currently underway for the Dawn Access initiative that will become effective November 1, 2017.

Second, as shown by Table 2, a change in heat value will require incremental deliveries by Direct Purchase customers. Appropriate time must be given to notify Direct Purchase customers of any changes in heat value which may impact their delivery volume upon contract renewal in order to allow them sufficient time to contract potentially incremental supply.

Witnesses: R. DiMaria
D. Small

Table 1

Heat Values

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec		Annual Average	Variance vs. 37.69
2001	37.78	37.86	37.65	37.69	37.68	37.45	37.43	37.39	37.39	37.35	37.38	37.30		**37.53**	**-0.16**
2002	37.46	37.45	37.57	37.46	37.35	37.38	37.40	37.38	37.35	37.47	37.51	37.66		**37.45**	**-0.24**
2003	37.67	37.75	37.88	37.64	37.49	37.66	37.46	37.45	37.41	37.42	37.60	37.64		**37.59**	**-0.10**
2004	37.69	37.75	37.64	37.55	37.59	37.41	37.36	37.35	37.25	37.37	37.42	37.50		**37.49**	**-0.20**
2005	37.59	37.58	37.58	37.40	37.35	37.45	37.85	37.43	37.41	37.27	37.32	37.57		**37.48**	**-0.21**
2006	37.43	37.54	37.45	37.28	37.33	37.27	37.27	37.24	37.27	37.38	37.45	37.43		**37.36**	**-0.33**
2007	37.45	37.55	37.51	37.48	37.33	37.43	37.35	37.29	37.26	37.29	37.44	37.60		**37.42**	**-0.27**
2008	37.59	37.61	37.59	37.42	37.31	37.39	37.40	37.41	37.39	37.58	37.71	37.89		**37.52**	**-0.17**
2009	37.80	37.65	37.58	37.55	37.42	37.40	37.43	37.49	37.45	37.56	37.62	37.58		**37.54**	**-0.15**
2010	37.60	37.64	37.58	37.62	37.61	37.69	37.62	37.63	37.68	37.65	37.70	37.76		**37.65**	**-0.04**
2011	37.71	37.71	37.66	37.79	37.66	37.76	37.70	37.71	37.98	37.69	37.69	37.72		**37.73**	**0.04**
2012	37.77	37.76	37.77	37.80	38.14	38.26	38.41	37.91	38.07	38.39	38.07	38.16		**38.04**	**0.35**
2013	38.08	38.02	38.04	38.18	38.55	38.55	38.49	38.43	38.43	38.11	38.30	38.29		**38.29**	**0.60**
2014	38.27	38.32	38.37	38.14	38.32	38.28	37.71	37.95	37.85	37.50	38.27	38.70		**38.14**	**0.45**
2015	38.49	38.62	38.69	38.37	37.93	37.94	37.99	37.92	38.70	38.51	38.61	38.62		**38.37**	**0.68**
2016	38.82	38.75	38.57	38.63	38.21	38.20	38.02	38.04	37.93					**38.35**	**0.66**
								2001 to 2015 average				37.71			
								2011 to 2015 average				38.11			

Witnesses: R. DiMaria
D. Small

Table 2

		Column 1	Column 2	Column 3	Column 4	Column 5
Line #	**2016 Budget**	Vols	Heat Value	assuming 2016 actual average		
			37.69	38.35		
	Total Demand -exclude - Company Use, LUF, UUF and Unbilled		Purchase Requirement in GJ's		incremental GJ's Requirement	Overall Cost Impact $ millions
1	Sales	7,877,220.4	296,892,438	302,113,836	5,221,397	25.2
2	Western T	2,282,756.9	86,037,108	87,550,228	1,513,120	7.3
3	Ontario T	1,371,510.4	51,692,228	52,601,330	909,103	4.4
4		11,531,487.8	434,621,774	442,265,394	7,643,620	36.9
	2015 Budget	Vols	Heat Value	assuming 2015 actual average		
			37.69	38.37		
	Total Demand -exclude - Company Use, LUF, UUF and Unbilled		Purchase Requirement in GJ's		incremental GJ's Requirement	Overall Cost Impact $ millions
5	Sales	7,322,375.9	275,980,349	280,932,568	4,952,219	23.9
6	Western T	2,484,920.6	93,656,657	95,337,242	1,680,585	8.1
7	Ontario T	1,341,055.2	50,544,369	51,451,343	906,973	4.4
8		11,148,351.7	420,181,375	427,721,152	7,539,777	36.4
	2014 Budget	Vols	Heat Value	assuming 2014 actual average		
			37.69	38.14		
	Total Demand -exclude - Company Use, LUF, UUF and Unbilled		Purchase Requirement in GJ's		incremental GJ's Requirement	Overall Cost Impact $ millions
9	Sales	7,351,118.4	277,063,653	280,374,125	3,310,472	16.0
10	Western T	2,204,144.3	83,074,197	84,066,802	992,605	4.8
11	Ontario T	1,570,676.9	59,198,811	59,906,143	707,332	3.4
12		11,125,939.5	419,336,662	424,347,071	5,010,409	24.2

Witnesses: R. DiMaria
D. Small

FRPO INTERROGATORY #17

INTERROGATORY

REF: Exhibit D1, Tab 2, Schedule 11, Page 11

Preamble: Paragraph 36 includes the sentence: "The Company is in the process of investigating whether or not there needs to be a change to the heat value conversion factor used in the budgeting process and will indicate its plans in due course."

We would like to understand more about the status of this investigation not only on the impact to the budgeting process, but also, the impact on direct purchase customers and system gas customers.

Using recent Heat Value history from actual deliveries, please provide a summary of the financial impact of these changes on budgeted system gas and on direct purchase deliveries and balancing.

RESPONSE

See response to FRPO Interrogatory #16 at Exhibit I.D1.EGDI.FRPO.16.

Witnesses: R. DiMaria
D. Small

FRPO INTERROGATORY #18

INTERROGATORY

REF: Exhibit D1, Tab 2, Schedule 11, Page 11

Preamble: Paragraph 36 includes the sentence: "The Company is in the process of investigating whether or not there needs to be a change to the heat value conversion factor used in the budgeting process and will indicate its plans in due course."

We would like to understand more about the status of this investigation not only on the impact to the budgeting process, but also, the impact on direct purchase customers and system gas customers.

Given that Union Gas varies the Heat Value of the gas on a monthly basis for the purposes of reconciling deliveries and consumption, what is Enbridge's view regarding the feasibility of programming this functionality during the IT system enhancement work required for Dawn Access?

RESPONSE

Based on a high level system review, Enbridge expects that the heat value conversion changes can be incorporated with the Dawn Access system enhancement.

Enbridge's plan for how the heat value conversion changes will be implemented is set out in response to FRPO Interrogatory #16 at Exhibit I.D1.EGDI.FRPO.16. Please refer to the response to FRPO Interrogatory #9 at Exhibit I.D1.EGDI.FRPO.9 for a status update and discussion of the Dawn Access system enhancement.

To minimize and hopefully ensure there are no delays to the Dawn Access Enhancement project timelines, the detailed requirements for system changes to support changes to the heat value conversion must begin in November 2016, subject to Board approval to proceed. Additional costs associated with the heat value conversion changes will be included with the incremental Dawn Access Enhancement project costs and will brought forward for future recovery.

Witnesses: R. DiMaria
D. Small

FRPO INTERROGATORY #19

INTERROGATORY

REF: Exhibit D1, Tab 2, Schedule 11, Page 11

Preamble: Paragraph 36 includes the sentence: “The Company is in the process of investigating whether or not there needs to be a change to the heat value conversion factor used in the budgeting process and will indicate its plans in due course.”

We would like to understand more about the status of this investigation not only on the impact to the budgeting process, but also, the impact on direct purchase customers and system gas customers.

Please provide Enbridge’s view on an appropriate implementation schedule including the potential to ensure appropriate direct purchase contracting in 2017.

RESPONSE

Please refer to the response to FRPO Interrogatories #16 and 18 at Exhibits I.D1.EGDI.FRPO.16 and I.D1.EGDI.FRPO.18.

Witnesses: R. DiMaria
D. Small

SEC INTERROGATORY #2

INTERROGATORY

[D1]

On September 6, Enbridge Inc. (parent of EGDI) announced the purchase of Spectra Energy (parent of Union Gas). Please explain how EGD, as the soon to be affiliate of Union Gas, plan to utilize the new increase market share to benefit consumers in the purchase of commodity, the transportation, and storage of natural gas. Please explain the expected impacts of the increased market share on the 2017 gas supply plan.

RESPONSE

Enbridge and Union Gas are not affiliates and would not be considered affiliates until any merger between Enbridge Inc. and Spectra Energy is approved.

Enbridge's 2017 gas supply plan was developed consistent with prior years and has been prepared in advance of the 2017 Fiscal Year based on Enbridge's known requirements at the time of its development for inclusion in the 2017 Rate Application.

Witnesses: K. Culbert
R. Small

SEC INTERROGATORY #3

INTERROGATORY

[D1]

Please explain the potential consequences of the proposed changes to TransCanada's Storage and Transportation Service (STS). If the National Energy Board approves the proposed changes, please explain how this will affect Enbridge's 2017 gas supply plan.

RESPONSE

The potential impacts of the changes to Storage Transportation Service ("STS") proposed by TransCanada PipeLines Inc. ("TCPL") are discussed at length in evidence provided by Enbridge in National Energy Board proceeding RH-001-2016 ("the STS proceeding"). TCPL has proposed to implement the changes effective April 1, 2017. An excerpt from Enbridge's written evidence is provided below:

> The changes that TCPL is proposing to the primary attributes of STS are fundamental and represent a change to the character of STS. The impacts to EGDI of these fundamental changes are significant and include:
>
> - accumulated STS Balances will be capped, and existing cumulative STS Balances that have been paid for by STS shippers that are above the cap will be terminated which will decrease the operational flexibility of the service while increasing costs since EGDI is forecasting that it will not have sufficient STS Balances to continue utilizing the service as intended by early 2019;
> - STS injections will be further restricted, since only 71% of the Withdrawal Quantity will be capable of firm injection while the remainder of injections will not be firm, but instead discretionary in nature thereby significantly decreasing the reliability and flexibility of STS for shippers like EGDI; and
> - STS injections will no longer be firm all year, but instead will only be firm during the specified summer period (April through October) which decreases the reliability and flexibility of the service since STS shippers will have to rely on discretionary diversions throughout the rest of the year. This does not acknowledge the operational reality of how STS is used by shippers like EGDI.[1]

In addition to impacting the reliability and flexibility of STS through the proposed changes to the primary attributes of STS discussed above, the Company is forecasting that it will incur incremental costs that range from $0.4 million to $0.8 million annually[2]

[1] RH-001-2016 Written Evidence of Enbridge Gas Distribution Inc. dated June 30, 2016 page14
[2] RH-001-2016 Enbridge Gas Distribution Inc. Responses to the National Energy Board Information Requests 1.3

Witnesses: M. Kirk
D. Small

due to required changes in its gas transportation portfolio as a result of limiting STS to one withdrawal location. The impact to the 2017 gas supply plan would be prorated in accordance with when the required gas transportation contract changes come into effect.

The Company is also forecasting that the elimination of accumulated STS Balances could result in \$0.7 million to \$6.0 million in incremental costs annually starting March 2019[3] which will not have an impact on the 2017 gas supply plan.

[3] IBID

Witnesses: M. Kirk
D. Small

TCPL INTERROGATORY #1

INTERROGATORY

Reference: 1) EB-2016-0215, Exhibit D1, Tab 2, Schedule 3, Page 5 of 13

2) EB-2016-0215, Exhibit D1, Tab 2, Schedule 9, Page 1 of 2

3) EB-2015-0175, Enbridge Application, Exhibit A, Tab 3, Schedule 1, Appendix C, Page 1 of 1

Preamble: In Reference 1, Enbridge states that it has entered into an agreement effective November 1, 2016 for 40,000 GJ/d of Link Pipeline capacity.

In Reference 2, Enbridge lists its Transportation and Storage contracts, including monthly demand charge information. The Link Pipeline monthly demand charge is listed as “varies”. The total contracted daily volume is listed as 42,202 GJ/d.

In Reference 3, Enbridge provides a landed cost analysis as part of its Application for Pre-Approval of a Long-Term Natural Gas Transportation Contract.

TransCanada notes Enbridge has committed to new upstream transportation contracts and requests further information on these arrangements.

Request: a) Please clarify Enbridge’s contracted capacity commitment to the Link Pipeline.

b) What is the meaning of the term “varies” in Reference 2? Please explain how the monthly demand charge for Enbridge’s Link Pipeline contract will be calculated.

c) Utilizing the same format as in Reference 3, please provide the landed cost analysis undertaken in support of the contracting decision noted in Reference 1.

Witnesses: M. Kirk
D. Small

RESPONSE

a) The contract is for 40,000 MMBTU/day which is equivalent to 42,202 GJ's per day. Information about the Link contract is also provided in response to FRPO Interrogatory #4 at Exhibit I.D1.EGDI.FRPO.4.

b) The monthly demand charge for the Link Pipeline varies depending on the time of year to correspond with a change in the Delivery Point. During the summer period (i.e., April through October) the Delivery Point is Tecumseh and the monthly demand charge is $1.591 per GJ per month. During the winter period (i.e., November through March) the Delivery Point is Dawn and the monthly demand charge is $1.735 per GJ per month.

c) The landed cost analysis has been provided in the table below.

Witnesses: M. Kirk
D. Small

Average Landed Cost of Link Capacity vs Alternatives: November 2016-October 2017

Pipeline/Service	Path	Pricing Point	Landed Cost (C$/GJ)
Link/STFT	Corunna-to-Dawn/Tecumseh	Michcon	3.69
Spot Market	n/a	Dawn	3.66
TCPL/FT	Empress-to-Union SWDA	Empress	4.54
Vector/FT-1	Chicago-to-Dawn	Chicago	3.73

Average Commodity Price (C$/GJ)

Pricing Point			Nov/16 - Oct/17
Michcon			3.54
Dawn			3.66
Empress			2.60
Chicago			3.47

Average Exchange Rate

			Nov/16 - Oct/17
C$/US$			1.255

Average Transportation Toll (C$/GJ)

Pipeline/Service	Path		Nov/16 - Oct/17
Link/STFT	MichCon-to-Corunna-to-Dawn		0.152
Link/STFT	MichCon-to-Corunna-to-Tecumseh		0.147
TCPL/FT	Empress-to-Union SWDA		1.654
Vector/FT-1	Chicago-to-Dawn		0.214

Average Fuel %

Pipeline/Service	Path		Nov/16 - Oct/17
Link/STFT	Corunna-to-Dawn		0.0%
Link/STFT	Corunna-to-Tecumseh		0.0%
TCPL/FT	Empress-to-Union SWDA		4.2%
Vector/FT-1	Chicago-to-Dawn		1.0%

Average ACA Charge (C$/GJ)

Pipeline/Service	Path		Nov/16 - Oct/17
Vector/FT-1	Border-to-Dawn		0.002

Average Abandonment Charge (C$/GJ)

Pipeline/Service	Path		Nov/16 - Oct/17
TCPL/FT	Empress-to-Union SWDA		0.14
Vector/FT-1	Border-to-Dawn		0.0004

Average Delivery Pressure Charge (C$/GJ)

Pipeline/Service	Path		Nov/16 - Oct/17
TCPL/FT	Empress-to-Union SWDA		0.03

Witnesses: M. Kirk
D. Small

TCPL INTERROGATORY #2

INTERROGATORY

Reference: 1) EB-2016-0215, Exhibit D1, Tab 2, Schedule 3, Page 5 of 13

2) EB-2016-0215, Exhibit D1, Tab 2, Schedule 9, Page 1 of 2

3) EB-2015-0175, Enbridge Application, Exhibit A, Tab 3, Schedule 1, Appendix C, Page 1 of 1

Preamble: In Reference 1, Enbridge states that it has entered into an agreement for 50,000 Dth/d of Vector capacity between December 1, 2016 and February 28, 2017.

In Reference 2, Enbridge lists its Transportation and Storage contracts, including monthly demand charge information.

In Reference 3, Enbridge provides a landed cost analysis as part of its Application for Pre-Approval of a Long-Term Natural Gas Transportation Contract.

TransCanada notes Enbridge has committed to new upstream transportation contracts and requests further information on these arrangements.

Request: a) Please explain why the 50,000 Dth/d Vector contract is not listed in Reference 2.

b) Utilizing the same format as in Reference 3, please provide the landed cost analysis undertaken in support of the contracting decision noted in Reference 1.

RESPONSE

a) Exhibit D1, Tab 2, Schedule 9 has been updated to reflect the referenced Vector contract. This update was provided to the Board and parties to this proceeding on November 7, 2016 and can be found at the following link:

Witnesses: M. Kirk
D. Small

http://www.rds.ontarioenergyboard.ca/webdrawer/webdrawer.dll/webdrawer/rec/549853/view/EGDI_Exhibit%20D_Updates_Operating%20and%20Maintenance%20Costs_20161107.PDF

b) The landed cost analysis is provided below.

Average Landed Cost of Incremental Vector Capacity vs Alternatives: December 2016-February 2017

Pipeline/Service	**Path**	**Pricing Point**	**Landed Cost (C$/GJ)**
Vector/FT-1	Chicago-to-Dawn	Chicago	4.23
Spot Market	n/a	Dawn	4.07

Average Commodity Price (C$/GJ)

Pricing Point			Dec/16 - Feb/17
Chicago			3.98
Dawn			4.07

Average Exchange Rate

			Dec/16 - Feb/17
C$/US$			1.288

Average Transportation Toll (C$/GJ)

Pipeline/Service	**Path**		Dec/16 - Feb/17
Vector/FT-1	Chicago-to-Dawn		0.220

Average Fuel %

Pipeline/Service	**Path**		Dec/16 - Feb/17
Vector/FT-1	Chicago-to-Dawn		0.7%

Average ACA Charge (C$/GJ)

Pipeline/Service	**Path**		Dec/16 - Feb/17
Vector/FT-1	Chicago-to-Border		0.002

Average Abandonment Charge (C$/GJ)

Pipeline/Service	**Path**		Dec/16 - Feb/17
Vector/FT-1	Border-to-Dawn		0.0004

Witnesses: M. Kirk
D. Small

TCPL INTERROGATORY #3

INTERROGATORY

Reference: 1) EB-2016-0215, Exhibit D1, Tab 2, Schedule 2, Page 22 of 28

Preamble: In Reference 1, Enbridge discusses its long-term contract with the NEXUS Gas Transmission ("NEXUS") Pipeline, commencing November 1, 2017.

Request: a) Has the Enbridge-NEXUS Precedent Agreement been amended since December 2, 2015? If so, please provide a summary of the changes as well as a blackline version of the updated Precedent Agreement.

b) Please list all regulatory authorizations required for NEXUS and provide an update on the status of each.

RESPONSE

a) The Enbridge-NEXUS Precedent Agreement has not been amended since December 2, 2015.

b) Section 7 of the Restated Precedent Agreement dated December 17, 2014 between the NEXUS Pipeline and the Company[1] lists the condition precedents, inclusive of the regulatory authorizations. An excerpt of section 7 is provided in Attachment 1 of this response. The Company has received the regulatory authorization required under Section 7 c) v) from the Board on December 17, 2016 and as discussed in response to Energy Probe Interrogatory #9 found at I.D1.EGDI.EP.9, the NEXUS Pipeline regulatory obligations are currently being reviewed by the Federal Energy Regulatory Commission under Docket CP16 11.

[1] EB-2015-0175, Exhibit A, Tab 3, Schedule 1, Appendix D, Pages 19-27

to construct, or to use reasonable efforts to cause others to construct, the authorized Phase II Facilities and to implement the firm transportation service contemplated in this Restated Precedent Agreement for Customer's Phase II Service on or about November 1, 2017, or such later date as may be designated by Pipeline in accordance with Section 3(c) above. If, notwithstanding Pipeline's due diligence, Pipeline, or Pipeline's designee(s), is unable to commence the Phase II service for Customer on November 1, 2017, or such later date as may be designated by Pipeline in accordance with Section 3(c) above, Pipeline will continue to proceed with due diligence to complete arrangements for such firm transportation service, and commence such service for Customer at the earliest practicable date thereafter. Subject to Section 9(a), Pipeline will neither be liable nor will this Restated Precedent Agreement or the Phase II Service Agreement be subject to cancellation if Pipeline, or Pipeline's designee(s), is unable to complete the construction of such authorized Project facilities and commence the Phase II service for Customer by November 1, 2017 or such later date as may be designated by Pipeline in accordance with Section 3(c) above.

7) Conditions Precedent. Commencement of service under the Phase II Service Agreement and Pipeline's and Customer's rights and obligations thereunder are expressly made subject to satisfaction or waiver, as applicable, of the following conditions precedent in Sections 7(b) and 7(c), provided that only Pipeline shall have the right to waive the conditions precedent set forth in Section 7(b) and only Customer shall have the right to waive the conditions precedent set forth in Section 7(c):

a) *Intentionally left blank.*

b) Pipeline's Conditions Precedent for Phase II Service.

i) Pipeline filing by April 1, 2015 the necessary requests with the FERC and/or NEB for approval to provide Phase II service as contemplated herein and in the Phase II Service Agreement;

ii) Subject to Section 7(d), Pipeline's receipt and acceptance in accordance with Section 7(f) by May 1, 2017, of all necessary Governmental Authorizations to construct, own, operate and maintain the Phase II Facilities (including FERC, NEB, and OEB authorizations, as applicable), all as described in Pipeline's applications as they may be amended from time to time, necessary to provide the Phase II service, including Customer's Phase II Service contemplated herein and in the Phase II Service Agreement;

iii) Pipeline (or Pipeline's owners or their respective affiliates) having received on or before May 1, 2017, a binding commitment from a financial institution(s) to provide the necessary financing of the construction of the Phase II Facilities;

iv) Other pipelines having received and accepted in accordance with Section 7(f) by May 1, 2017, all necessary Governmental Authorizations to construct, own, operate and maintain the Phase II Facilities, all as described in their applications as they may be amended from time to time, necessary to provide the Phase II service including Customer's Phase II Service contemplated herein and in the Phase II Service Agreement;

v) Pipeline receiving approval, no later than thirty (30) days after its acceptance of the certificates and authorizations specified in Section 7(b)(i), from its Management Committee, or similar governing body, to expend the capital necessary to construct

Witnesses: M. Kirk
D. Small

the Phase II Facilities and to proceed with the Phase II-related firm pipeline transportation arrangements with other pipelines for service on the Phase II Facilities;

vi) Pipeline's receipt no later than four (4) months prior to the Phase II Service Commencement Date of all necessary authorizations required to construct the Phase II Facilities necessary to provide the Phase II firm transportation service including Customer's Phase II Service contemplated herein and in the Phase II Service Agreement, other than those specified in Section 7(b)(ii);

vii) Pipeline's procurement, no later than four (4) months prior to the Phase II Service Commencement Date, of all rights-of-way, easements or permits (in form and substance acceptable to Pipeline, acting reasonably) necessary for the construction and operation of the Phase II Facilities;

viii) Pipeline's completion of construction of the Phase II Facilities and all other facilities required to render Customer's Phase II Service pursuant to the Phase II Service Agreement and for other customers subscribing for Phase II service and Pipeline being ready, able and authorized to place such facilities into gas service; and

ix) The completion of the construction of the facilities necessary to create the pipeline capacity subscribed to Pipeline as part of Phase II of the Project by other pipelines, as applicable, and each such Party being ready, able and authorized to place such facilities into service.

c) <u>Customer's Conditions Precedent.</u>

i) Intentionally left blank.

ii) Customer's acceptance, no later than 30 days following receipt of Initial Receipt Point Information in accordance with Section 1(c), of the initial receipt points proposed by the Pipeline for Phase II transportation service;

iii) Customer's confirmation to Pipeline, no later than 90 days following receipt of the Estimated Phase II Commencement Date, that it has completed its review and approval of regional supply necessary to support natural gas supply arrangements associated with Customer's service under the Phase II Service Agreement, respectively; and

iv) If, pursuant Section 3(d)(ii), the Final Reservation Rate exceeds the Estimated Reservation Rate, then Customer's receipt, no later than 60 days following receipt of the requisite internal corporate approvals of such Final Reservation Rate for Phase II;

v) Customer's receipt and acceptance of the approvals from the OEB for its application related to the Customer's Phase II Service no later than October 1, 2015; and

vi) Subject to Section 7(d), Customer's receipt and acceptance no later than 30 days following satisfaction of the condition in Section 7(c)(iii), of any necessary Customer Authorizations identified in accordance with Section 2(a) of this Restated Precedent Agreement.

d) <u>Temporary Waiver of Conditions Precedent – Governmental Authorizations</u>. Notwithstanding Sections 7(b)(ii), 7(b)(iv), 7(c)(iii) and 7(c)(iv) and subject to Section 24, either Party may, in its sole discretion, temporarily waive satisfaction of its conditions precedent listed above for a period of 90 days. During such a delay, upon reasonable request by the other Party, the Party waiving its condition precedent shall use commercially reasonable efforts to provide timely notices to the other Party in writing regarding the filing of any applications for such Governmental Authorizations or Customer Authorization, as the context requires, and will provide periodic updates regarding the status of such applications, including notice when each of the authorizations are received, obtained, rejected or denied. The Party temporarily waiving it condition precedent shall also promptly notify the other Party in writing as to whether each of the Governmental Authorizations or Customer Authorizations, as the context requires, received or obtained are acceptable to such Party. If the Party temporarily waiving its condition precedent has not satisfied the conditions precedent associated with the receipt of all Governmental Authorizations or Customer Authorizations, as the context requires, within ninety (90) days' time, either Party may terminate this Restated Precedent Agreement on thirty (30) days' written notice and no Pre-Service Costs will be payable by Customer.

e) With respect to each condition precedent set forth in Section 7(b) of this Restated Precedent Agreement, with the exception of the conditions precedent set forth in clauses (vii) and (viii) of Section 7(b), Pipeline shall provide notice to Customer within five (5) days of the satisfaction of such condition precedent that the condition precedent has been satisfied. With respect to each condition precedent set forth in Section 7(c) of this Restated Precedent Agreement, Customer shall provide notice to Pipeline within five (5) days of the satisfaction of each such condition precedent that the condition precedent has been satisfied.

f) Unless otherwise provided for herein, the Governmental Authorization(s) contemplated in Section 1 of this Restated Precedent Agreement must be issued in form and substance satisfactory to both Parties, acting reasonably. For purposes of this Restated Precedent

Witnesses: M. Kirk
D. Small

Agreement, such Governmental Authorization(s) shall be deemed satisfactory if issued or granted with terms and conditions which are: (i) consistent with this Restated Precedent Agreement and all ancillary agreements and documents to be delivered pursuant to this Restated Precedent Agreement for the applicable service; and (ii) to the extent not contemplated by this Restated Precedent Agreement or any of the ancillary agreements and documents, not materially onerous on Pipeline, as determined by Pipeline, acting reasonably, and will not otherwise have a material adverse effect on Customer. Customer shall notify Pipeline in writing not later than fifteen (15) days after Pipeline notifies Customer of the issuance of the FERC and/or NEB certificate(s), authorization(s) and approval(s), including any order issued as a preliminary determination on non-environmental issues, contemplated in Section 1 of this Restated Precedent Agreement if Customer determines, acting reasonably, that such certificate(s), authorization(s) and approval(s) will have a material adverse effect on Customer. Customer cannot assert that any authorization will have a material adverse effect on Customer unless: (i) the governing provisions of such authorization differ materially and adversely from the provisions requested by Pipeline in its application, unless the provisions requested by Pipeline were inconsistent with the terms of this Restated Precedent Agreement; and (ii) such differences materially and adversely affect the rate to be charged pursuant to the rate agreement contemplated herein, or the terms and conditions of service pursuant to the service agreement contemplated herein, and the Parties cannot mutually agree upon a modification or alternative to such provision which preserves the relative economic positions of the Parties under the operative agreement(s). All other Governmental Authorizations that Pipeline must obtain must be issued in form and substance acceptable to Pipeline, acting reasonably. All Governmental Authorizations that Pipeline is required by this Restated Precedent Agreement to obtain must be duly granted by the FERC, NEB, or other governmental agency or authority having jurisdiction, and must be final and no longer subject to rehearing or appeal; provided, however, Pipeline may waive the requirement that such Governmental Authorizations be final and no longer subject to rehearing or appeal. If any of the Governmental Authorizations are issued on material terms not acceptable to either Party, subject to the foregoing provisions of this Section 7(f), then the non-accepting Party, acting reasonably, shall give notice to the other Party, and the Parties shall promptly meet and work in good faith in an attempt to agree upon a commercially acceptable resolution for both Parties, each Party in its sole discretion, to continue forward with respect to Phase II. If, after thirty (30) days, the Parties are unable to agree upon a mutually acceptable resolution, either Party shall have the right to terminate this Restated Precedent Agreement and, if executed, the Phase II Service Agreement and Phase II Rate agreement. Any termination of this Restated Precedent Agreement by a Party pursuant to this Section will be without liability between the Parties including in respect of the Customer being required to pay any Pre-Service Costs. Notwithstanding the foregoing, if the Parties cannot agree on a modification or alternate provision, Pipeline may, in its sole discretion, appeal or otherwise pursue rehearing, reconsideration or clarification by the applicable regulatory authority of any such provision(s) which Customer alleges will have a material adverse effect on it, and Customer may not terminate this Restated Precedent Agreement until a final order or decision is rendered by such regulatory authority which does not grant relief that is satisfactory to Customer, acting reasonably, to address such material adverse effect, or

180 days from the date that Pipeline makes its application for rehearing, reconsideration or clarification, whichever occurs first.

g) The Customer Authorization(s) contemplated in Section 2 of this Restated Precedent Agreement shall be deemed satisfactory if issued or granted in form and substance substantially as requested, or if issued in a manner acceptable to Customer and such Customer Authorization(s), as issued, will not otherwise have a material adverse effect on Pipeline. Pipeline cannot assert that any authorization will have a material adverse effect on Pipeline unless: (i) the governing provisions of such authorization differ materially and adversely from the provisions requested by Customer in its application, unless the provisions requested by Customer were inconsistent with the terms of this Restated Precedent Agreement; and (ii) such differences materially and adversely affect the rate to be charged pursuant to the rate agreement contemplated herein, or the terms and conditions of service pursuant to the service agreement contemplated herein, and the Parties cannot mutually agree upon a modification or alternative to such provision which preserves the relative economic positions of the Parties under the operative agreement(s). If any of the Customer Authorizations are issued on terms not acceptable to either Party, subject to the foregoing provisions of this Section 7(g), then the non-accepting Party shall give notice to the other Party, and the Parties shall promptly meet and work in good faith in an attempt to agree upon a commercially acceptable resolution for both Parties, each Party in its sole discretion, to continue forward with respect to Phase II. If, after thirty (30) days, the Parties are unable to agree upon a mutually acceptable resolution, either Party shall have the right to terminate this Restated Precedent Agreement and, if executed, the Phase II Service Agreement and Phase II Rate Agreement. Any termination of this Restated Precedent Agreement by a Party pursuant to this Section will be without liability between the Parties including in respect of the Customer being required to pay any Pre-Service Costs.

h) In the event the Estimated Phase II Commencement Date is changed to a date later than November 1, 2017 in accordance with Section 3(c), the Parties agree that each of the dates in Sections 3(d)(ii), 7(b)(i) through 7(b)(iii), Sections 7(c)(ii) through 7(c)(iv), and Section 10 will be changed to a later date by the same amount of time as such change to the Estimated Phase II Commencement Date.

8) Pre-Service Costs. If Customer is in material breach of any of its obligations arising pursuant to this Restated Precedent Agreement and such material breach is not cured within 30 days of notice to Customer by Pipeline of such breach, or if such breach is not capable of being cured within 30 days, and Customer is not continuing thereafter in good faith and with diligence to cure such breach, and, as a result thereof, the Phase II Service Commencement Date does not occur, then Customer shall, at the option and election of Pipeline, reimburse Pipeline within thirty (30) days of Pipeline's invoice, for its pro-rata share, based on Customer's MDQ for Phase II service to total contracted MDQ for Phase II service by all customers with executed Restated Precedent Agreements, for the Pre-Service Costs incurred or otherwise committed to by Pipeline up to the date of the occurrence of the material breach which resulted in the Phase II Service Commencement Date to not occur. In no event shall Customer's exposure to Pre-Service Costs exceed $163 million U.S. dollars if Customer's MDQ for Phase II service is 110,000 Dth/d, or $219 million U.S. dollars if Customer's MDQ for Phase II service is 150,000 Dth/d. Customer's liability for its share of the Pre-Service Costs in accordance with this Section 8 constitutes a genuine pre-estimation of Pipeline's

Witnesses: M. Kirk
D. Small

TCPL INTERROGATORY #4

INTERROGATORY

Reference: 1) EB-2016-0215, Exhibit D1, Tab 2, Schedule 10, Page 1 of 1

Preamble: In Reference 1, Enbridge provides 2017 monthly price forecasts for Empress, NYMEX, and Chicago.

Request: a) Please provide a forecast of Dawn prices for the same time period, using the same methodology as in Reference 1.

RESPONSE

Please see the updated evidence at Exhibit D1, Tab 2, Schedule 10, highlighted in red, which was filed through the Board's Regulatory Electronic Submission System on Tuesday November 8, 2016.

Witnesses: M. Kirk
D. Small

VECC INTERROGATORY #4

INTERROGATORY

Reference: D1/T1/

a) What is the date of the Gas Supply Memorandum?

RESPONSE

The Gas Supply Memorandum, filed at D1, Tab 2, Schedule 2, was prepared in August 2016.

Witnesses: M. Kirk
D. Small

VECC INTERROGATORY #5

INTERROGATORY

Reference: D1/T2/S3/pg.7 Table 1; D1/T2/S8/pg.1

a) Please explain why the Western Canadian Supplies in Table 1 are not the same as those in the table at the latter reference (i.e.1,820,545 vs 1,746,776 10^3m^3).

RESPONSE

The volume of 1,820,554.9 10^3m^3 identified at Exhibit D1, Tab 2, Schedule 3, page 7 represents the total amount of gas purchased including the forecast TCPL long haul transportation fuel requirement of 73,778.8 10^3m^3 as shown at Exhibit D1, Tab 2, Schedule 3, page 1 of 2, Column 1, Item 1.6.

Witnesses: M. Kirk
D. Small

BOMA INTERROGATORY #21

INTERROGATORY

Ref: Exhibit D2, Tab 1, Schedule 1, Paragraph 99

(a) Has EGD decided to issue an RFP for customer care services, or is it still considering a further renewal of the Accenture agreement?

(b) Why would EGD not elect to engage in a competitive process at this time?

(c) Please provide EGD's business case for going to market versus remaining with Accenture at this time.

RESPONSE

(a) As first indicated in EB-2014-0276, the Company's CCSA with Accenture runs until the end of 2019. Future decisions on procurement strategies beyond 2019 will be made closer to that timeframe. Enbridge's proposal to continue the CCSPDA for the years from 2017 to 2019 is consistent with this timeframe. As stated in evidence (Exhibit D2, Tab 1, Schedule 1, pages 31 to 32), the CCSPDA that the Board approved in EB-2012-0459 permits Enbridge to record costs associated with benchmarking, tendering and potential transition of customer care services to a new services provider(s).

(b) With three years remaining in the current contract term it is still too early to initiate a competitive procurement strategy.

(c) The Company is in the process of developing a long-term strategy around customer service delivery and future-state meter-to-cash requirements. Plans around how to go to market for these services will be developed as part of that overall strategy.

Witness: D. McIlwraith

VECC INTERROGATORY #6

INTERROGATORY

Reference D2/T1/S1/Pg.4

a) Please explain why the 2017 continuation of the Customer Care Services Procurement Deferral Account ("CCSPDA"), and Rate 332 Deferral Account ("R332DA") require approval in this proceeding whereas none of the other 2016 accounts appear to require similar explicit approval.

RESPONSE

Approval for the continuation of the 2017 CCSPDA and 2017 R332DA is explicitly sought in this proceeding because the prior approvals for each of these accounts was for a specific term that did not initially include 2017.

Within Enbridge's 2014 to 2018 Custom Incentive Rate Application, EB-2012-0459, the CCSPDA was approved for 2014 through 2016, while as part of Enbridge's 2016 Rate Adjustment proceeding, EB-2015-0114, the R332DA was approved for 2016.

Enbridge's other 2017 deferral and variance accounts have already been approved for an extended period including 2017, either as part of Enbridge's 2014 to 2018 Custom Incentive Rate Application, EB-2012-0459, or through another proceeding.

Witness: R. Small

VECC INTERROGATORY #7

INTERROGATORY

Reference: D/T2/S1/pg. 8

a) Below is the table presented in EB-2015-0114 showing the forecast for the issuance of $200 million in long-term debt. Please provide the actual amounts for that issuance including the actual Canada Yield at the time of issuance.

Table 2

Item No.	Amount ($MM)	Issue Date	Term (Yrs)	Canada Yield	Corporate Spread	Coupon	Amortized Issue Costs	Effective Cost
1	200	16-Oct	10	2.84%	1.40%	4.24%	0.05%	4.29%

b) Please provide the source and date of the 1.80% 10 year and 2.30% 30 year Canada yield.

c) Please provide average actual (day close) 10 and 30 year Canada yield for the month of October 2016.

RESPONSE

a) Table 2 referenced above reflects the original 2016 forecast debt issuance included within the EB-2015-0114 pre-filed evidence. The updated 2016 forecast debt issuance reflected within the EB-2015-114 Final Rate Order, as per the approved Settlement Agreement, was provided within the response to Energy Probe Interrogatory #7, at I.C2.EGDI.EP.7, within that proceeding. For a comparison of the actual versus forecast 2016 issuance, please refer to the response to SEC Interrogatory #5, at I.E1.EGDI.SEC.5, within this proceeding.

b) The forecast Canada yields were derived from a survey of financial institutions conducted in May 2016.

c) Average actual 10 and 30 Canada yields for the month of October were 1.17% and 1.82%, respectively.

Witnesses: R. Craddock
R. Small

BOMA INTERROGATORY #22

INTERROGATORY

Ref: Exhibit E1, Tab 3, Schedule 1, Pages 2-3

(a) What was the term of the $300 million debt issued in August 2016?

(b) Please confirm that the lower actual cost of that 2016 debt issuance of 3.42% compared to forecast 4.47% (approximately $3 million) has increased EGD's 2016 earnings by that amount, and such increase is subject to earnings sharing. If treatment is different, please explain fully.

(c) What has been the change in the coupon rates on (i) ten year; (ii) thirty year; Canadian corporate high rated bonds (with ratings equivalent to that for EGD), if any, since August 2016 to today? What is the market's current forecast for these prices as of August 2017?

RESPONSE

a) The August 2016 debt issuance of $300 million was for a term of 10 years.

b) The Company confirms that the calculation of 2016 actual utility results, and resultant earnings sharing amount, will incorporate the impact of the actual 2016 debt issuance. The Company does not confirm the quantum of the earnings impact as approximately $3 million, as that figure appears to be derived by multiplying the actual $300 million issuance amount by the variance in the effective rate, implying the debt was effective for the full year. Neither the actual issuance ($300 million in August 2016), nor the forecast issuance ($250 million in March 2016) were fully effective in 2016. The quantum of benefits is also impacted by the variance in the amount of debt issued, the variance in the timing of the issuance, and the resulting corresponding impact on short-term debt requirements.

c) Current indicative coupon rates for 10 year Enbridge bonds are consistent with the 2.50% coupon on Enbridge's August 2016 $300 million issuance. A summary of Canadian corporate bond issuances since August 2016 follows:

Witnesses: R. Craddock
R. Small

Date	Issuer	Rating	Term	Coupon
September 8	Suncor	A(L)/A-/Baa1	10 years	3.00%
September 13	Brookfield Asset Management	A(L)/A-/Baa2	10.6 years	3.80%
October 4	Lower Mattagami	A(H)/A2	10 years	2.31%
September 7	Fortis Alberta	A(L)/A-	30 years	3.34%
September 8	Suncor	A(L)/A-/Baa1	30 years	4.34%
October 3	Gaz Metro	A/A+	30 years	3.28%

Enbridge's forecast for 2017 underlying Government of Canada Bonds based on an October 2016 survey has decreased by 30 basis points for both 10 year and 30 year bonds compared to pricing noted in Exhibit E1, Tab 3, Schedule 1.

Witnesses: R. Craddock
R. Small

ENERGY PROBE INTERROGATORY #11

INTERROGATORY

Reference: Exhibit E1,Tab 2, Schedule 1, Page 1

Preamble: The Company is unable to provide the forecast at this time using the prescribed calculation, but will update this evidence when the Board issues its Cost of Capital Parameter Updates for 2017 Applications in November of this year. For purposes of deriving estimated rate impacts for the 2017 application, the Company has applied the value of 8.77%, which is based on the July 2016 inputs being applied to the Board's established approach to calculating ROE.

a) Please update the 2017 Cost of Capital Schedules for the Board- Determined values as in the Board's Direction by Letter of October 27, 2016.

b) Please provide updates to show the impact of the COC update on the 2017 Revenue Requirement, Utility Income and Deficiency

RESPONSE

a) Evidence at Exhibit E1, Tab 2, Schedule 1 was updated on Tuesday, November 1, 2016 and filed through the Board’s Regulatory Electronic Submission System.

b) Please refer to the Company’s updated evidence, filed on Tuesday, November 8, 2016, which reflects the impact of the Board determined Return on Equity for 2017, of 8.78%, on the Company’s 2017 Cost of Capital, Utility Income, Allowed Revenues, and Deficiency.

Witnesses: R. Small
M. Suarez

SEC INTERROGATORY #4

INTERROGATORY

[E1-3-1, p.2]

What is the basis for the coupon rate forecasts for the 2017 issuances? What is the basis for the Canada yield and coupon spread forecasts?

RESPONSE

The Canada yield is based on the forecast Government of Canada bond yield derived from a survey of financial institutions conducted in May 2016.

Corporate spreads are based on indicative spreads received from financial institutions.

Witnesses: R. Craddock
R. Small

SEC INTERROGATORY #5

INTERROGATORY

[E1-3-1, p.2]

Please provide a chart showing the forecast long-debt issuances and rates made in each of the past three annual rates applications, and the actual debt issuances and rates for those issuances. Please explain all material variances.

RESPONSE

For a comparison of actual versus approved forecast debt issuances, please see the attachment to this response.

2014

In 2014, a 3 year MTN in the amount of $300 million was issued as a result of forecast elevated working capital requirements.

2015

In 2015, $400 million of 10 year MTNs and $170 million of 30 year MTNs were issued compared to $300 million of 10 year MTNs and $300 million of 30 year MTNs as forecast. A higher proportion of 10 year MTNs were issued as a result of lower than forecast demand for 30 year MTNs.

2016

In 2016, a forecast $150 million FRN was not issued due to higher than forecast liquidity.

Witnesses: R. Craddock
R. Small

	Forecast Term Debt Issuance								Actual Term Debt Issuance							
Item No.	Amount ($MM)	Issue Date	Type	Term (Yrs)	Canada Yield	Corporate Spread	Coupon	Effective Cost (Incl. Hedge)	Amount ($MM)	Issue Date	Type	Term (Yrs)	Canada Yield	Corporate Spread	Coupon	Effective Cost (Incl. Hedge)
Year: 2014		Approved forecast provided in pre-filed evidence (EB-2012-0459)														
1.	215.0	September 2014	MTN	10	2.70%	1.20%	3.90%	3.86%	215.0	August 2014	MTN	10	2.06%	1.09%	3.15%	3.24%
2.	215.0	September 2014	MTN	30	3.20%	1.50%	4.70%	4.48%	215.0	August 2014	MTN	30	2.61%	1.39%	4.00%	3.89%
3.									300.0	April 1, 2014	MTN	3	1.23%	0.62%	1.85%	1.97%
Year: 2015		Approved forecast provided in IR I.E1.EGDI.VECC.14 (EB-2014-0276)														
1.	300.0	September 2015	MTN	10	1.90%	1.20%	3.10%	3.37%	400.0	September 2015	MTN	10	1.51%	1.80%	3.31%	3.62%
2.	300.0	September 2015	MTN	30	2.30%	1.55%	3.85%	3.96%	170.0	September 2015	MTN	29	1.80%	2.20%	4.00%	4.44%
Year: 2016		Approved forecast provided in IR I.E1.EGDI.EP.7 (EB-2015-0114)														
1.	250.0	March 2016	MTN	10	1.90%	1.80%	3.70%	4.47%	300.0	August 2016	MTN	10	1.08%	1.42%	2.50%	3.42%
2.	150.0	March 2016	FRN	3	0.9% CDOR	1.00%	1.90%	1.90% [2]								

Notes:

1. Enbridge's actual April 2014 issuance of a $300 million three-year note has been removed from the calculation of long and medium-term debt costs, and has been re-categorized to short-term debt in a manner consistent with the treatment approved within the Settlement Agreement in Enbridge's 2015 Rate Adjustment proceeding, EB-2014-0276.

2. Within Enbridge's approved 2016 rates, the forecast March 2016 issuance of a $150 million three-year Floating Rate Note was removed from the calculation of long and medium-term debt costs, and was re-categorized to short-term debt, consistent with the Board approved 2016 Settlement Agreement (EB-2015-0114).

Witnesses: R. Craddock
R. Small

ENERGY PROBE INTERROGATORY #12

INTERROGATORY

Reference: Exhibit E2, Tab 1, Schedule 2

a) Please provide a version of Exhibit E2 Tab 1, Schedule 2, Page 1 that includes the issue dates and terms of existing and forecast debt.

b) Please discuss the factors playing into the decisions to issue short, medium, and long term debt.

c) Are these decisions made By Enbridge (Corporate) Treasury or by EGD?

d) For the proposed 2017 $300 million debt issues, please confirm the proposed terms and the basis of the proposed mix (term etc.).

e) With Regard to preferred shares please indicate if these are issued by Enbridge (and assigned to EGD) or EGD directly

f) Please provide a schedule showing actual and if applicable, forecast preferred shares (pfs) and the Grade(s), Rate and Reset provision for each issue.

g) How much of the $100 million pfs will be reset in 2017 and what will be the forecast reset rate(s) and reduction in annual costs.

RESPONSE

a) Please refer to the attachment to this interrogatory for an updated version of the referenced exhibit which includes the requested information.

b) The tenor of debt issuances is based on external factors including market demand and pricing as well as internal factors including its fixed to floating ratio.

c) Funding decisions are made jointly by Enbridge Treasury and Enbridge Gas Distribution Inc.

d) Terms of the forecast 2017 $300 million debt issues are provided in Table 2 of Exhibit E1, Tab 3, Schedule 1.

Witnesses: R. Craddock
R. Small

e) The preferred shares were issued directly by Enbridge Gas Distribution Inc. in 1999.

f) There are no forecast preferred share issuances for Enbridge Gas Distribution Inc. Preferred share dividends are paid at a rate of 80% of the prime rate. On July 1, 2019, and every five years thereafter, the Group 3, Series D preference shares can be converted, at the holder's option, into Group 2, Series D preference shares, on a one-for-one basis, and will pay fixed cumulative cash dividends that are not less than 80% of the Government of Canada yield applicable to the fixed dividend period. The Group 3, Series D preference shareholders opted not to convert their shares into Group 2, Series D preference shares effective July 1, 2014.

g) No preferred shares reset in 2017.

Witnesses: R. Craddock
R. Small

SUMMARY STATEMENT OF PRINCIPAL
AND CARRYING COST OF
TERM DEBT
2017 UPDATED FORECAST

Line No.	Coupon Rate	Issue Date	Term (Yr's)	Maturity Date	Col. 1 Average of Monthly Averages Principal ($Millions)	Col. 2 Effective Cost Rate	Col. 3 Carrying Cost ($Millions)	
Medium Term Notes								
1.	8.85%	October 2, 1995	30	October 2, 2025	20.0	8.970%	1.8	
2.	7.60%	October 29, 1996	30	October 29, 2026	100.0	8.086%	8.1	
3.	6.65%	November 3, 1997	30	November 3, 2027	100.0	6.711%	6.7	
4.	6.10%	May 19, 1998	30	May 19, 2028	100.0	6.161%	6.2	
5.	6.05%	July 3, 1998	25	July 5, 2023	100.0	6.383%	6.4	
6.	6.90%	November 15, 2002	30	November 15, 2032	150.0	6.950%	10.4	
7.	6.16%	December 16, 2003	30	December 16, 2033	150.0	6.180%	9.3	
8.	5.21%	February 24, 2006	30	February 25, 2036	300.0	5.183%	15.5	
9.	4.77%	December 19, 2006	15	December 17, 2021	175.0	5.310%	9.3	
10.	5.16%	December 3, 2007	10	December 4, 2017	191.7	5.220%	10.0	
11.	4.04%	November 22, 2010	10	November 23, 2020	200.0	5.209%	10.4	
12.	4.95%	November 22, 2010	40	November 22, 2050	200.0	4.990%	10.0	
13.	4.95%	September 7, 2011	39	November 22, 2050	100.0	4.731%	4.7	
14.	4.04%	November 22, 2013	7	November 23, 2020	200.0	2.801%	5.6	
15.	4.50%	November 22, 2013	30	November 23, 2043	200.0	4.198%	8.4	
16.	1.85%	April 22, 2014	3	April 24, 2017	-	1.970%	- [1]	
17.	3.15%	August 22, 2014	10	August 22, 2024	215.0	3.241%	7.0	
18.	4.00%	August 22, 2014	30	August 22, 2044	215.0	3.889%	8.4	
19.	4.00%	September 11, 2015	29	August 22, 2044	170.0	4.436%	7.5	
20.	3.31%	September 11, 2015	10	September 11, 2025	400.0	3.619%	14.5	
21.	2.50%	August 5, 2016	10	August 5, 2026	300.0	3.415%	10.2	
22.	3.20%	August 15, 2017	10	August 15, 2027	56.3	3.252%	1.8	Forecast
23.	4.00%	August 15, 2017	30	August 15, 2047	56.3	4.021%	2.3	Forecast
24.					3,699.3		174.5	
Long-Term Debentures								
25.	9.85%	November 21, 1994	30	December 2, 2024	85.0	9.910%	8.4	
26.					85.0		8.4	
27.	Removal of separately treated CIS 64% assumed debt of 2017 $19.7M rate base value				(12.6)	5.350%	(0.7)	
28.	Total Term Debt				3,771.7		182.2	

Notes:

1. Enbridge's April 2014 issuance of a $300 million three-year note has been removed from the calculation of long and medium-term debt costs, and has been re-categorized to short-term debt in a manner consistent with the treatment approved within the Settlement Agreement in Enbridge's 2015 Rate Adjustment proceeding, EB-2014-0276.

Witnesses: R. Craddock
R. Small

BOMA INTERROGATORY #23

INTERROGATORY

Exhibit F1, Tab 2, Schedule 1, Page 1

(a) Please provide a step-by-step explanation, starting with the 2017 Placeholder from the EB-2012-0459 decision of how the 2017 revenue requirement is established.

(b) Please note for each item in the Placeholder, the amount of the Placeholder, the amount by which it is proposed to be adjusted, what the adjustment factor or formula is, and which items, such as depreciation, are not adjusted. Please provide reference to the applicable evidence to where each adjustment calculation is displayed.

(c) Please explain how revenue at existing rates is calculated. Please refer to where in the evidence the calculation is found, and show the revenue at existing rates. I assume they are the 2016 rates, combined with the 2017 volumes, but what are the other components of the calculation? Please explain how the 2016 revenue requirement and rates are utilized, if at all, other than described in this section (c), in the determination of the 2017 revenue requirements and rates.

RESPONSE

a & b) Please see the response to BOMA Interrogatory #3, found at Exhibit I.A1.EGDI.BOMA.3. The updating of placeholder amounts for 2017 has been undertaken in the same manner as in prior Rate Adjustment proceedings during this Custom IR term.

c) The revenue at existing rates is derived based on the 2017 forecast of customer numbers, contract demand, and volumes by rate class and type of service. The rates are based on the July 1, 2016 QRAM rates which were the rates in effect when the 2017 budget was prepared. The derivation of the revenue at existing rates by rate class can be found at Exhibit H2, Tab 5, Schedule 1, pages 1 to 7 at Columns 2, 3 and 4. A summary of the revenue at existing rates can be found at Exhibit H2, Tab 2, Schedule 1, Column 4. The revenue at existing rates (less DPAC revenue) is used to determine the test year revenue deficiency/sufficiency as found at Exhibit F1, Tab 2, Schedule 1, page 1, Column 8, Line 27.

Witnesses: A. Kacicnik
R. Small

The sufficiency or deficiency is the total amount by which the Company needs to decrease or increase from the current level (July 1, 2016 QRAM rates) to match the proposed 2017 revenue requirement. If there is a revenue sufficiency, it means the Company would recover too much revenue under the current rates. Therefore, rates need to be reduced. If there is a revenue deficiency, it means the Company would not recover enough revenue under the current rates. As a result, rates need to be increased.

Witnesses: A. Kacicnik
R. Small

ENERGY PROBE INTERROGATORY #13

INTERROGATORY

References: Exhibit F1, Tab 2, Schedule 1, Page 1; EB-2015-0114, Exhibit I.F1.EGDI.STAFF.9 Attachment 1

a) Please provide Variance Report for 2017 in a similar format to the exhibit provided in the above Interrogatory Response to Board Staff.

RESPONSE

Please refer to the response to Board Staff Interrogatory #3, at Exhibit I.A1.EGDI.STAFF.3 for the requested variance report.

Witness: R. Small

BOARD STAFF INTERROGATORY #16

INTERROGATORY

Ref: G1/T1/S1/para18

With respect to the Dawn transportation service (DTS), please indicate if the details of the cost allocations and service terms were developed in the Dawn access settlement (EB-2014-0323) or whether they appear for the first time in this 2017 rate application.

RESPONSE

Yes, the terms of the DTS service and derivation of the transportation charges reflect the Dawn Access Settlement (EB-2014-0323) dated October 22, 2014. Please see Section (2) of the Settlement Agreement, pages 10 and 13 (EB-2014-0323 found at Exhibit B, Tab 2, Schedule 1, pages 10 and 13).

Witnesses: A. Kacicnik
B. So

ENERGY PROBE INTERROGATORY #14

INTERROGATORY

Reference: Exhibit G1, Tab 1, Schedule 1, Page 4; Exhibit G2, Tab 5, Schedule 3, Page 2

Preamble: Rate 332 has been allocated 60% (or approximately $17.4 M) of the Segment A revenue requirement.

As described in Exhibit D2, Tab 1, Schedule 1, the forecast Rate 332 revenues are subject to the Rate 332 Deferral Account, which will record for clearance to the Company's bundled customers, any variance in Rate 332 revenues collected from Rate 332 transportation customers versus the amount forecast to be collected from those customers in 2017, net of any amounts recorded in the 2017 GTAITCRRDA. Dawn Transportation Service (DTS):

a) Confirm in more detail, the assumptions and calculation of actual/estimated total costs and 2017 revenue requirement for Segment A (Albion Pipeline) and confirm the basis of the 40:60 RR split (capacity?) between Enbridge and Rate 332 customers.

b) Confirm EGD will monitor and determine the actual split based on 2017 volumes.

c) If, based on experience, the RR split is different, then please describe actions EGD will take, in addition to recording Rate 332 Costs and Revenues in the 2017 GTAITCRRDA; for example what adjustments will EGO make to cost allocation/rate design in 2018?

RESPONSE

a) The 2017 revenue requirement for Segment A is based on the forecast of costs for Segment A of the GTA project as filed in Enbridge's Custom IR proceeding. In that proceeding the Company determined placeholder amounts (i.e., revenue requirements) for each year of its 5 year Custom IR term (2014 to 2018). The 2017 revenue requirement has been updated for the 2017 cost of capital (ROE and cost of debt) as per the Company's Custom IR framework. This is the only cost element that has been updated for 2017.

   The Rate 332 revenues are designed to recover the shippers' portion of Segment A costs. As per the Board's decision in EB-2012-0451, 60% of the annual revenue

Witnesses: A. Kacicnik
B. So

requirement for Segment A is to be recovered from shippers through Rate 332 contract demand ("CD") charges. The 60:40 split of revenue requirement costs was determined by the Board based on the amount of capacity on Segment A that the Company indicated it would make available to 332 shippers (i.e., the Company indicated it would make 60% of total Segment A capacity available to Rate 332 shippers).

Note that both the revenue requirement of Segment A and the 60:40 split between Rate 332 shippers and the Company's bundled customers are based on forecast.

b) Not confirmed. There is no need to determine the actual split based on actual 2017 volumes. Even if capacity contracted by Rate 332 shippers would be less than 60%, as per the Board's decision the Company would still need to recover 60% of the revenue requirement from Rate 332 shippers. This would manifest itself in higher Rate 332 contract demand charges versus the situation / outcome where the available capacity (i.e., 60%) is fully contracted by Rate 332 shippers.

c) Not applicable. Please see response to part b) above.

Witnesses: A. Kacicnik
B. So

BOARD STAFF INTERROGATORY #17

INTERROGATORY

Ref: G2/T1/S1/p3 of 28

Please provide the historical revenues and costs to serve, and the revenue-to-cost ratios for Rate 125 for the past 5 years.

RESPONSE

Please see the table below which depicts the Rate 125 forecast revenues, allocated cost to serve from the fully allocated cost study and resulting revenue to cost ratios for the past 10 years.

Rate 125 - Revenue to Cost Ratio
(millions of dollars)

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Total Revenues	1.32	3.43	6.58	7.39	7.29	9.79	10.88	9.68	9.85	10.87	11.66
Cost of Service	3.04	3.62	6.39	7.42	7.34	10.03	10.53	9.45	9.81	12.17	11.66
Over / Under Contribution	(1.72)	(0.19)	0.19	(0.04)	(0.04)	(0.25)	0.35	0.23	0.04	(1.29)	(0.00)
Revenue to Cost Ratio (%)	0.43	0.95	1.03	0.99	0.99	0.98	1.03	1.02	1.00	0.89	1.00

Witnesses: A. Kacicnik
B. So

FRPO INTERROGATORY #20

INTERROGATORY

REF: Exhibit G2, Tabs 4-6 and associated schedules

Preamble: With the evolution of gas supply sourcing from primarily Western Canada to other purchase locations, we would like to understand better the impacts on the allocation of costs for pipeline contracts as functionalized to load balancing.

At a high level, please provide the following information:

a) Any changes to the methodology employed in EB-2012-01459.

b) Any changes to the discretionary functionalization associated with separating seasonal from annual requirements.

c) Please provide the per cubic metre impact for load-balancing costs for Rates 1 and 6 embedded in the 2015, 2016 and 2017 rates.

d) At a high level with the reduction in cost of long-haul associated with winter seasonal load balancing, please provide the drivers that would contribute to the impact on load balancing rates.

e) If not answered in the subsections above, please ensure a description of how Commodity and Transportation costs from a short-haul centric model are being functionalized using an Empress based reference price.
    i) Further please ensure there is a description of how the transportation costs are allocated to transportation and load balancing.

f) What is Enbridge's current view on the need for a Dawn Reference Price (as approved by the Board for Union Gas in their EB-2015-0181 proceeding):
    i) To address market price signal
    ii) To address cost allocation and functionalization issues

Witnesses: J. Collier
A. Kacicnik
D. Small
B. So

RESPONSE

a) No. Also, please see response to part e) below.

b) No. Also, please see response to part e) below.

c) Please see below for the Board approved load balancing unit rates from each QRAM for 2015 and 2016 and the proposed unit rate as part of the current application. The load balancing unit rates are updated with each of the Company's QRAM applications.

	2015, 2016 and 2017 Load Balancing Unit rates (cents per cubic meter)								
	EB-2014-0348	EB-2015-0027	EB-2015-0163	EB-2015-0242	EB-2015-0327	EB-2016-0021	EB-2016-0184	EB-2016-0260	EB-2016-0215
	2015 Q1	2015 Q2	2015 Q3	2015 Q4	2016 Q1	2016 Q2	2016 Q3	2016 Q4	2017 Proposed
Rate 1	1.0888	1.0912	1.1314	1.1431	1.4198	1.5750	1.6556	1.6558	1.6613
Rate 6	0.9324	0.9325	1.0433	1.0532	1.3220	1.4672	1.5434	1.5439	1.5300

d) Everything else being equal, a reduction in the cost of long-haul associated with winter seasonal load balancing would result in a reduction to the load balancing rates.

The reduction to the load balancing rates (stemming from the shift from long haul to short haul transportation) will be seen, everything else being equal, as part of January 1, 2017 QRAM rates.

The impact of this reduction is not seen within the 2017 rate adjustment application as the 2017 forecast gas cost to operations budget is developed and captures the impact of the 2017 supply mix change relative to the 2016 supply mix and does not capture changes in costs / prices for those supplies or transportation. This approach is consistent with the Company's approved QRAM methodology which adjusts rates in each quarter to reflect changes in commodity, upstream transportation and load balancing costs, but does not capture impacts due to changes in supply mix. This approach is further discussed in gas cost evidence at Exhibit D1, Tab 2, Schedule 3, page 8, paragraphs 23 and 24 and is consistent with the Company's past rate case filings.

Further, it should be highlighted there are no Unabsorbed Demand Charges ("UDC") forecast in 2017.

Witnesses: J. Collier
A. Kacicnik
D. Small
B. So

In past years the Company incurred the cost of additional long haul firm transportation ("FT") capacity to provide load balancing service to all bundled customers (system gas and direct purchase). A certain amount of long haul FT was utilized in lieu of an equivalent amount of peaking service (less reliable than FT) or STFT (more expensive than FT) to meet demand in peak and near-peak conditions. The UDC costs represented the unutilized portion of the long haul FT capacity that the Company acquired for load balancing purposes. Although UDC costs were recovered from customers via a deferral account, not having to bear these costs in 2017 represents an overall reduction in load balancing costs to all bundled customers.

e) The response to this question first lays out basic information about the Company's gas supply plan, followed by a description of how the gas supply charges are developed using the Empress price as the reference price for the gas supply charge and how transportation costs are classified / split between transportation and load balancing charges.

As per the Board-approved approach, Enbridge's gas supply plan is developed by forecasting the gas supply needs specific to Enbridge's sales / system gas customers, Mean Daily Volume ("MDV") deliveries from direct purchase customers, and the amount of gas supply required to balance forecast year round.

The gas supply plan cost is based on a forecast (i.e., 21-day forecast of market prices for 12 month forecast period) of price indices at the various supply basins / market hubs, plus the associated transportation cost to deliver the gas to the franchise area. Through this approach Enbridge develops a Purchased Gas Variance Account ("PGVA") reference price of its forecast upstream acquisition costs, including commodity, transportation and delivered supply costs. This approach also provides the Company with the means to adjust its forecast gas supply plan costs and its rates on a quarterly basis using the Board-approved Quarterly Rate Adjustment Mechanism ("QRAM").

Once the forecast has been completed, Board-approved cost allocation and rate design principles are used to allocate those costs between different types of service and customer classes through the establishment of the gas supply, transportation, and load balancing charges.

All variances from the forecast costs are captured in the PGVA, which ensures that ratepayers and the Company are held whole with respect to gas supply plan acquisition costs.

Witnesses: J. Collier
A. Kacicnik
D. Small
B. So

The disposition of PGVA balances through the cost adjustment rider (Rider C) to sales / system gas customers and to direct purchase customers follows the same methodology that underpins the cost allocation and rate design principles.

Gas Supply

Enbridge provides system gas to its residential, commercial, and industrial customers who do not procure their own gas supply either on their own, or through gas marketers or vendors.

The rate Enbridge charges to customers for system gas (i.e., gas supply charge) is subject to regulatory approval and 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 QRAM process.

Empress is a trading hub and a receipt point for the TransCanada Mainline near the Alberta – Saskatchewan border. Its price index is (readily) available through various sources. It is an appropriate reference point for costing of gas supplies from the Western Canadian Sedimentary Basin (“WCSB”) given it is in a very close proximity to the WCSB, (but at the same time is the furthest away supply hub utilized by Enbridge).

Empress being so close to the gas supply basin means that the prices for gas supply at Empress reflect the cost of commodity itself, while the prices of gas supplies procured 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.

Enbridge sources gas supplies from a number of market hubs and transports supplies via a number of transportation paths to achieve diversity and reliability of its gas supply plan.

As discussed above, the Company uses the Empress price inclusive of fuel as a reference price to design its gas supply charge. Accordingly, the cost of gas supply commodity is recovered from system gas customers through the Company’s gas supply charge.

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, also to load balancing. Transportation costs are recovered from System gas and Western T-service customers, and load balancing costs are recovered from all bundled customers.

Transportation

Enbridge contracts for upstream capacity on pipelines such as TCPL, Vector and Nexus to transport gas supplies from the various market hubs to its franchise area. The cost of upstream capacity that is contracted at 100% load factor to meet annual average demand for system gas, Western T-Service and Dawn T-service customers is recovered through the Company's transportation charges. Ontario T-Service and unbundled customers arrange for their own transportation to the Company's franchise area.

This approach of flowing gas on upstream pipelines at 100% load factor (i.e., the same amount of gas is delivered to the franchise area each day year round), which is a concept / approach equivalent to the Mean Daily Volume (MDV) delivery obligation for direct purchase customers, is facilitated by the close proximity of storage to Enbridge's franchise area. Excess supplies in the summer are stored for withdrawal in the winter.

To reflect this operating practice of meeting annual average demand, upstream transportation costs (inclusive of the deemed transportation costs from the gas supply section above) are classified as 100% annual demand and are recovered from customers based on bundled transportation delivery volumes by the type of transportation service and by rate class.

The cost of upstream transportation which is utilized only for part of the year to help the Company meet seasonal and peak demands on the system (i.e., demand beyond the demand that is met via 100% LF transportation / MDV delivery by direct purchase customers and storage withdrawals) is recovered through the load balancing charge. In other words, such upstream capacity is used to provide load balancing to all customers. Load balancing charges are recovered from all system gas and direct purchase customers.

It should also be noted that the cost of forecast UDC, if any, is removed from the forecast gas supply plan costs. The UDC cost is recovered from customers via a deferral account.

f) As noted in the sections above, Enbridge sources gas supplies from a number of market hubs and transports supplies via a number of transportation paths to achieve diversity and reliability of its gas supply plan. While the proportions of gas supplies sourced at the various market hubs will change over time versus the current gas supply plan, the Company will continue to diversify its purchases among the various market hubs.

Witnesses: J. Collier
A. Kacicnik
D. Small
B. So

If the Dawn price were to be used as a reference price for the gas supply charge, then the resulting gas supply charge would not reflect the actual cost of landing gas supplies for the Company's system gas customers in Ontario. As noted previously, the Company will continue to diversify its purchases among various market hubs. To the extent that the gas supply charge based on the Dawn price would deviate from the utility's operating practices to source and transport gas supplies to its system gas customers, it would create cost variances which would need to accumulate in the Purchased Gas variance Account ("PGVA") and would have to be trued up at a later date. These variances would occur even if there was no change to gas supply prices in the marketplace. The variances would occur because gas supply charge revenues would not be based on the (actual) costs to provide service.

In other words, using a reference price for gas supply that is not determined based on the Company's costs to provide service (i.e., gas supply plan) will result in cost impacts that will need to be cleared to customers on a deferred basis. Such an approach would also represent a deviation from the principle of using cost incurrence / cost causality as the basis for setting rates.

An Ontario landed price that is based on Enbridge's supply plan and that reflects diversity of purchases among the various market hubs and associated transportation paths would provide an appropriate reference price for the gas supply charge.

However, the structure of Western T-service is not compatible with an Ontario landed reference price. Should an Ontario landed price be adopted as a reference price for the gas supply charge, Western T-service might need to be discontinued.

Also, to facilitate a shift to an Ontario landed reference price, Enbridge would need to change a number of its business processes and systems and it would need to communicate the changes to its customers. Accordingly, stakeholder support for the change and for recovery of the associated costs of implementation would be essential to support a shift to an Ontario landed reference price.

Witnesses: J. Collier
A. Kacicnik
D. Small
B. So

BOARD STAFF INTERROGATORY #18

INTERROGATORY

Ref: H1/12/S1/para6/Table 1

With respect to the table of rate class impacts, please explain why Rate 125 is experiencing a 7.3% increase and Rate 300 a 3.0% increase in 2017.

RESPONSE

Rate 125 is an unbundled distribution service. As approved by the Board, the derivation of Rate 125 delivery charges is based on the cost of the Company's extra high pressure network of pipelines greater than 4 inches in diameter only. Accordingly, delivery charges on Rate 125 are considerably lower than delivery charges on other Enbridge's rates.

In 2016, the Company implemented into service the GTA project, its largest project in the recent past. The revenue requirement associated with the GTA project caused increased rate impacts for all customer classes.

As part of the Final Rate Order at the outset of its Custom IR term the Company filed estimated rate impacts for the 2014 to 2018 term (EB-2012-0459, Final Rate Order, Appendix D, page 1).

At the time the Company estimated the implementation of the GTA project would cause an approximate 30% increase in Rate 125 delivery charges and proposed to spread the estimated impacts over three years (so that at the end of the three years the Rate 125 revenue to cost ratio would equal 1.0). Please see the table below for the estimated impacts from the EB-2012-0459 Final Rate Order.

	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5
	2014	2015	2016	2017	2018
Rate Class	Final	Estimated	Estimated	Estimated	Estimated
	Delivery Rate Impact	Delivery Rate Impact	Rate Impact	Delivery Rate Impact	Delivery Rate Impact
125	-11.0%	3.0%	10.0%	9.9%	9.9%

While the impact of 7.3% in 2017 is greater than impacts for Enbridge's other customers, it is less than the Company estimate of 9.9% prepared at the outset of the Custom IR term.

Witness: A. Kacicnik

Also, it is important to highlight that the higher impact is due to the lower base (i.e., considerably lower delivery charges on Rate 125 versus other Enbridge's rates) to which the increase is applied. As an illustration, a $1 increase on a $100 bill will be shown as a 1% increase, while a $1 increase on a $10 bill will be shown as a 10% increase.

Finally, the 7.3% increase in rate 125 delivery charges achieves revenue to cost ratio of 1.0 in 2017 (see response to Board Staff Interrogatory #17 at Exhibit I.G2.EGDI.STAFF.17 or Exhibit G2, Tab 2, Schedule 1, page 1). Therefore, the Company no longer anticipates a rate impact for Rate 125 customers in 2018 that would be greater than that of other Enbridge customers.

BOARD STAFF INTERROGATORY #19

INTERROGATORY

Ref: H1/T2/S1/para14

With respect to the Interruptible rate terms of service, please confirm that Enbridge is not requesting any relief in this proceeding and that the evidence is provided for information only.

RESPONSE

This is confirmed.

Witnesses: A. Kacicnik
D. Small

ENERGY PROBE INTERROGATORY #15

INTERROGATORY

Reference: Exhibit H1, Tab 2, Schedule 1, Page 1

Preamble: Enbridge will undertake analysis of the value of seasonal credit costs and will discuss with customers whether there are any further changes to the Interruptible Service Program that would make it more attractive.

a) Confirm that the design of the Interruptible Rate takes account of all relevant costs per the FACS in setting the 145 and 170 Interruptible Rates.

b) Please explain how a seasonal credit may work with/without changes to the FACS allocated costs

RESPONSE

a) This is confirmed.

b) The value/cost of the seasonal credit is determined outside of the fully allocated cost study ("FACS"). The corresponding cost of the seasonal credit is allocated based on each firm customer class' peak day related load balancing requirements. Accordingly, the cost of the seasonal credit is then recovered from firm customers through the load balancing charge and paid out to interruptible (seasonal) customers in four installments from December to March. As the costs are allocated back to the firm service rate classes based on peak day responsibility, the majority of the costs are recovered from Rate 1 and 6 heat sensitive customers.

Witnesses: A. Kacicnik
D. Small

VECC INTERROGATORY #8

INTERROGATORY

Reference: H2/T7/S1

a) The annual bill comparisons appear to be mislabelled as they show EB-2016-0215 rates as the same as those of EB-2016-0184 (both at 37.69). If this is correct please provide the correct rate comparison.

b) What is the (approximate) rate impact for a residential customer of 3,048 m3 (heating and water) for each $10 million reduction or increase in the revenue requirement (for simplicity assume the $10 million change is in cost of capital)?

RESPONSE

a) The annual bill comparisons are not mislabeled. Exhibit H2, Tab 7, Schedule 1 depicts the typical bill impacts comparing the Company's proposed 2017 rates and bills with the existing rates and bills. Column 1 depicts the typical annual bill based on the proposed EB-2016-0215 2017 rates, Column 2 depicts the typical annual bill based on the existing EB-2016-0186 July 1, 2016 QRAM rates. Column 3 depicts the dollar change in the bill. Column 4 depicts the percent change in the bill. The heading at the top of the chart indicates an estimated heat value of gas of 37.69 MJ per m^3.

b) Assuming a $10 million dollar increase or decrease in revenue requirement (based on a corresponding change in the cost of capital), a typical residential customer's annual bill would increase or decrease accordingly by approximately 0.6% or approximately $5 a year (all other things being equal).

Witness: J. Collier