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VIA RESS, EMAIL and COURIER

March 19, 2014

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
2300 Yonge Street, 27th Floor
Toronto, Ontario
M4P 1E4

Dear Ms. Walli:

Re: EB-2014-0039 (QRAM Application) – Interrogatory Responses

Enbridge Gas Distribution Inc. ("Enbridge") filed its April 1, 2014 QRAM Application on March 12, 2014. In response to the QRAM Application, Enbridge received a number of information requests, as well as letters of comment.

Attached to this letter are responses to the information requests received from Ontario Energy Board ("OEB") Staff, Canadian Manufacturers & Exporters ("CME") and Industrial Gas Users Association ("IGUA").

Comments were received from several parties, including Consumers Council of Canada ("CCC"), CME, IGUA, Federation of Rental-housing Providers of Ontario ("FRPO") and Vulnerable Energy Citizens Coalition ("VECC").

IGUA's letter indicates that while the quantum of the proposed clearance of the Purchased Gas Variance Account ("PGVA") is significant, there is no evidence of shortcomings in the manner in which EGD has managed its gas supply exigencies during the recent extreme weather period. IGUA indicates that, subject to responses to the information requests, it sees no reason why the clearance of the balance in the PGVA should be denied.

CME requests that parties be given an additional two days after responses to the information requests are sent, to provide comments to the QRAM application. Enbridge acknowledges that request, but is concerned about being able to conclude this process in time to have new rates in place for April 1st. In the event that parties were provided until Friday, March 21st to make further submissions, Enbridge would require until the end of Monday, March 24th to file responding submissions. It is not clear whether the Board can accommodate this timing and still issue a decision that can be implemented for April 1st. As set out within Enbridge's Application letter, the Company had requested that the Board issue a decision on or before March 26th in order to facilitate that outcome. Based upon further inquiries, Enbridge has learned that it could implement a decision issued as late as March 28th, if the decision approved the QRAM Application as filed (including rates, Rider C, and customer notices).

The main theme within the letters of comment received from CCC, FRPO, and VECC is that any approval of this QRAM Application should be interim, and a process should be ordered to allow for comprehensive examination of the subject gas costs, and to consider steps to mitigate the impact of the cost increases.

Enbridge does not agree that an expanded process is necessary. Enbridge has provided detailed information within this proceeding (in prefiled evidence and in response to interrogatories), that explains the reasonable actions taken to manage gas supply during a winter that has been much colder than anticipated within Enbridge's gas supply plan. As highlighted within the response to CME Interrogatory #1 (Exhibit I, Tab 2, Schedule 1), the Company's gas supply plan forecasts a 1 in 5 winter, yet the actual conditions have been 1 in 25 as the end of February and are projected to be the coldest on record (since 1954) as of the end of March. Enbridge develops a cost effective gas supply plan to meet its one in five planning criteria on the principles of diversity, flexibility, and reliability in order to meet peak day demand and demand throughout the year. Based on these principles, the gas supply plan is composed of various long haul and short haul transportation contracts which provide access to various production basins and storage facilities at Tecumseh and Dawn. Also included are delivered supplies at Dawn, peaking supplies, and curtailment which are utilized to meet seasonal, near peak, and peak day demands. The transportation and storage assets are the lower cost components on a per unit basis with high firm annual fixed payment commitments, while delivered supply, peaking, and curtailment are higher unit cost but more flexible components of the plan. The lower cost assets are maximized first when actual demand exceeds projected demand. Since Enbridge's portfolio is sized for a one in five recurrence, the Company had no choice but to use the higher cost tools of delivered supplies, peaking supplies and curtailment to meet the projected one in sixty winter it is faced with. Essentially, the Company used the only tools available to it while ensuring reliability to its customers. The volumetric and financial impacts of the recent cold weather experience can be found at Exhibit Q2-2, Tab 1, Schedule 1, page 5 of 10.

If Enbridge was to set its gas supply plan on more conservative assumptions, for example a one in ten winter (43.7 degree days), then it would acquire more long haul and short haul transportation contracts which provide access to various production basins and storage facilities at Tecumseh and Dawn. This would be more expensive in a normal year, but would reduce the reliance on higher cost delivered and peaking supplies in an exceptional winter, such as experienced this year. Another option would be to carry additional storage capacity as a contingency and/or require that storage deliverability remain at a level such that peak day demand can be supplied as late as March 1st. EGD notes that the more conservative planning assumptions are similar to the gas supply planning parameters utilized by Union Gas, and would mitigate the cost consequences of meeting a winter colder that assumed in a 1 in 5 gas supply plan. As discussed in response to CME Interrogatory #1 (Exhibit I, Tab 2, Schedule 1), the Company is willing to investigate more conservative planning assumptions within future year gas supply plans. That, however, is a topic for a future proceeding.

Enbridge submits that an expanded process for comprehensive examination of the subject gas costs is inconsistent with, and is not contemplated by, the Board's established QRAM process. As explained throughout the prefiled evidence, and further within the attached interrogatory responses, the prescribed QRAM process is meant to be mechanistic and summary. The QRAM process was thoroughly examined, and ruled upon, within the Board's EB-2008-0106 Methodologies for Commodity Pricing, Load Balancing and Cost Allocation for Natural Gas Distributors Proceeding.

Enbridge submits that it would be an inappropriate departure from the approved QRAM methodology to order interim rates and an expanded discovery and hearing process within this proceeding.

Similarly, as explained within the attached interrogatory responses, Enbridge does not believe that rate smoothing is appropriate in this case.

Yours truly,

(Original Signed)

Andrew Mandyam
Director, Regulatory Affairs

Encl.

cc: Mr. Fred Cass, Aird & Berlis LLP
All Interested Parties EB-2012-0459

BOARD STAFF INTERROGATORY #1

INTERROGATORY

Board staff understands colder than normal weather had an impact on customer demand and on natural gas prices. Can you please provide a breakdown of the effect of higher prices for Enbridge's planned purchases and higher prices for purchases made to meet higher customer consumption levels (referred in question 2 below as incremental purchases) as of March 31, 2014.

RESPONSE

Monthly and Daily index prices are reported in Market publications such as Canadian Gas Price Reporter ("CGPR")

The monthly index represents the markets' view of the value for gas in a future month. Purchasing gas from a supplier at that index means that the fixed daily volume will be priced at that unit rate each day. In contrast, the daily index represents the markets value or price of gas for each day throughout the month.

The attached table provides a breakdown of the effect of higher prices for Enbridge's planned or budgeted purchases as well as the effect higher prices had on the incremental purchases required to meet the increased demand.

Column 1 of the attached table represents the monthly purchases and projected acquisition costs as per the Company's 2014 gas supply plan. (For a detailed description of the development of the supply plan please see the response to CME Interrogatory #1 found at Exhibit I, Tab 2, Schedule 1).

Column 2 and Column 6 represent the monthly prices used for the purposes of developing the January 2014 QRAM. The QRAM is based upon a 21-day average of forward monthly index pricing applied to the budgeted monthly volumes.

Column 3 represents the effective price payable to acquire the planned or budgeted volume. As described in response to Board Staff Interrogatory # 4 found at Exhibit I, Tab 1, Schedule 4, the Company sends out monthly RFP's for purposes of acquiring that supply. As described in Board Staff Interrogatory #4 it may not always be possible to totally acquire that supply and the price payable for that supply is contingent upon the prices identified within the RFP i.e., the monthly or daily supply is acquired through a combination of monthly and daily pricing dependent on the RFP responses.

Column 4 represents the variance between the budgeted cost and the actual cost of the budgeted volume.

Column 5 represents the incremental volume acquired in the month due to the change in demand because of the colder than budgeted weather.

Column 7 represents the average price payable for those incremental supplies and reflects the cost of acquiring those supplies on a daily basis as required.

Column 8 represents the variance between the budgeted unit rate applied to the incremental volume compared to the actual cost of those incremental supplies at the market prices.

Column 9 represents the actual monthly index price and Column 10 represents the weighted average of the reported daily index prices. The average cost payable by EGD is weighted volumetrically and is therefore, unlikely to equal the simple monthly average.

A review of the contributing variance can be broken down as follows:

January:
Responses received to the monthly RFP for Western Canadian supplies were primarily tied to the daily index price which is reflected in the average price of $4.11/GJ being higher than the monthly index for Western Canadian supply.

Peaking Services are acquired through an RFP process conducted in the fall and responses include a Demand Charge and a Commodity component. The commodity component is typically tied to the Iroquois index and since these supplies are required on the coldest days of the year, the prices will reflect market conditions on such days.

As part of the supply plan a level of Delivered Supply is identified and costed for budgeting purposes at the forward monthly index at Dawn. Similar to Western Canadian supplies the Company was able to meet its budgeted volume through a combination of monthly and daily priced contracts. The incremental volume however, was acquired at the daily index which, as was described in Q2-2, Tab 1, Schedule 1, page 6, paragraph 14, increased throughout the month of January.

February:
Similar to the January responses, the monthly RFP responses for Western Canadian supplies were primarily tied to the daily index price. In February the daily index was over 1.5 times higher than the monthly index causing costs for Western Canadian supplies to increase.

Delivered supplies in the month of February continued to climb throughout the month due to the combination of colder weather and reduced storage deliverability (in line with the multi peak methodology used by the Company) thereby necessitating short term purchases to meet demand. At the same time the daily index rose in excess of 2 times the monthly index.

March:
March is based upon a forecast of monthly prices that are higher than those forecast as part of the January QRAM. The Company also included within its forecast for March prices for incremental Delivered supply at prices 1.5 times the forecast monthly price due to continued colder weather and declining deliverability that necessitates short term purchases to meet demand.

Item #		Column 1	Column 2	Column 3	Column 4	Column 5	Column 6	Column 7	Column 8	Column 9	Column 10
	January										
		Budget Volume - TJ's	Budget Price $/GJ	Actual Price $/GJ	Variance $(000's)	Incremental Volume - TJ's	Budget Price $/GJ	Actual Price $/GJ	Variance $(000's)	Monthly Index $/GJ	Average Daily Index $/GJ
1.1	Western Canadian Supplies	12,411.3	3.38	4.11	9,053.4	6,568.7	3.38	4.29	5,977.0	3.66	4.24
1.2	Peaking Supply (1)	1,051.8	5.09	42.43	39,282.1	517.2	5.09	59.73	28,261.7	N/A	45.27 (2)
1.3	Chicago Supply	5,854.8	3.81	5.26	8,526.0	(343.8)	3.81	5.26	(500.7)	5.02	8.27
1.4	Delivered Supply	4,650.0	4.38	5.42	4,855.3	10,780.7	4.38	7.27	31,154.1	4.88	7.11
1.4					61,716.8				64,892.1		
1.5									126,608.90		
	February										
		Budget Volume - TJ's	Budget Price $/GJ	Actual Price $/GJ	Variance $(000's)	Incremental Volume - TJ's	Budget Price $/GJ	Actual Price $/GJ	Variance $(000's)	Monthly Index $/GJ	Average Daily Index $/GJ
2.1	Western Canadian Supplies	11,407.7	3.34	6.49	35,987.5	5,733.2	3.34	7.24	22,403.0	4.40	7.15
2.2	Peaking Supply	307.6	5.45	42.74	11,468.6	(203.8)	5.45	43.43	(7,740.9)	N/A	27.51
2.3	Chicago Supply	5,288.2	3.81	8.77	26,224.7	(246.1)	3.81	8.77	(1,220.2)	8.77	12.45
2.4	Delivered Supply	4,200.0	4.40	18.90	60,932.0	11,704.5	4.40	20.50	188,516.9	7.93	17.15
2.5					134,612.8				201,958.8		
2.6									336,571.52		
	March										
		Budget Volume - TJ's	Budget Price $/GJ	Estimated Price $/GJ	Variance $(000's)	Incremental Volume - TJ's	Budget Price $/GJ	Estimated Price $/GJ	Variance $(000's)	Monthly Index $/GJ	Average Daily Index $/GJ
3.1	Western Canadian Supplies	9,949.3	3.30	5.27	19,526.9	9,239.0	3.30	5.27	18,132.7	5.27	N/A
3.2	Peaking Supply	-	-	-	-	-	-	-	-	N/A	N/A
3.3	Chicago Supply	5,854.8	3.79	6.97	18,589.3	-	3.79	6.97	-	6.89	N/A
3.4	Delivered Supply	4,650.0	4.40	8.21	17,735.9	6,000.0	4.40	13.33	53,565.0	8.21	N/A
3.5					55,852.0				71,697.7		
3.6									127,549.72		

note - 1 - the cost for peaking supplies includes a demand charge component
note - 2 - an arithmatic average of Daily Iroquois prices in a particular month is not representative of the cost payable for peaking service.
- the commodity cost payable for peaking service is tied to the daily price when the service is called

BOARD STAFF INTERROGATORY #2

INTERROGATORY

Given the timelines for issuing a decision in this proceeding and the "non- mechanistic" nature of the application, please provide Enbridge's view were the Board to consider the following:

(i) Approve the establishment of the utility price effective April 1, 2014 and the disposition of the deferral account balances as of April 1, 2014 that do not include amounts related to incremental gas purchases made over the 2013 / 2014 winter period on a final basis. Approve the disposition of the deferral account balances as of April 1, 2014 that do include amounts related to incremental gas purchases made over the 2013 / 2014 winter period on an interim basis pending a more comprehensive review.

(ii) Approve the establishment of the utility price effective April 1, 2014 and the disposition of the deferral account balances as of April 1, 2014 that do not include amounts related to incremental gas purchases made over the 2013 / 2014 winter period on a final basis. Defer the disposition of the deferral account balances as of April 1, 2014 that do include amounts related to incremental gas purchases made over the 2013 / 2014 winter period until a more comprehensive review takes place.

RESPONSE

Enbridge's QRAM application was filed with the Ontario Energy Board (the "Board") in the normal course. The Company has followed the Board approved methodology, per the EB-2008-0106 Decision, for the purposes of establishing the April 1, 2014 QRAM Reference Price and for the clearance of the PVGA balance over a prospective 12 month period. It has followed this same process since 2010 and has not deviated from this process in the instant QRAM application. It is the Company's view that it has followed the mechanistic QRAM process established by the Board.

In its EB-2008-0106 Decision the Board found that a 12 month forecast period for establishing the reference price and a quarterly rate adjustment mechanism were appropriate. It also found that the then existing deferral and variance accounts remain appropriate and that disposition of the balances contained in these accounts should occur on a 12 month rolling basis. Enbridge continues to agree with these findings.

The Company views this QRAM application as having been filed in normal course. Treating it any differently could have unintended consequences such as those outlined in the response to Board Staff Interrogatory #3 found at Exhibit I, Tab 1, Schedule 3. For these reasons the Company believes that the Board should approve the change in the Reference Price as filed and also approve the disposition of the PGVA balance as filed. As mentioned above the disposition of the PGVA balance is consistent with the Board's recent Decision on QRAM process and methodology as well as QRAM Decisions since.

However, should the Board determine that a different, non-mechanistic treatment, be applied to this QRAM application, such as one of the options outlined in this interrogatory, the Company would prefer option (i). This would allow for investigation of any unintended consequences prior to deviating from established practice and methodology.

BOARD STAFF INTERROGATORY #3

INTERROGATORY

Please provide Enbridge's view on whether the Board should consider disposing of the PGVA balance as of March 31, 2014 over a period of 2, 3 or 4 years. Please also calculate the annualized total bill impacts for a typical residential customer using a 2-year, 3-year and 4-year disposition period to dispose of Enbridge's PGVA balances.

RESPONSE

The Ontario Energy Board (the "Board") should not consider disposing of the Purchase Gas Variance Account ("PGVA") balance over a period of 2, 3, or 4 years for the following reasons, and as explained further in the following pages:

- Enbridge believes that such a drastic change in policy would represent a departure from the methodology that has been established, and refined in EB-2008-0106, as in the public interest
- The policy and process have been established in large part to reflect competitive commodity market dynamics.

Within the evidence in this proceeding, the Company has determined the forecast PGVA reference price to be incorporated into rates and ongoing rolling twelve month forecast of balances in the PGVA to be cleared through a rate rider in the manner as established within the Board's Decision within the EB-2008-0106 Methodologies for Commodity Pricing, Load Balancing and Cost Allocation for Natural Gas Distributors proceeding.

The EB-2008-0106 proceeding took place in 2008, where the Board on its own motion commenced a proceeding for purposes of determining the methodology to be used by natural gas distributors in Ontario for gas commodity pricing, load balancing, and cost allocation between the supply and delivery functions in relation to regulated gas supply.

In the Board's decision dated September 18, 2009 in that proceeding, it approved the manner in which gas distributors were to forecast natural gas reference prices to be included within rates within future QRAM proceedings. It also determined the manner in which amounts were to be accumulated within and the appropriate mechanistic timing and ongoing clearance of rolling twelve month amounts to be included within the PGVA.

Witnesses: J. Collier
K. Culbert
A. Kacicnik

The Board's decision was made in response to the evidence put forward by the natural gas distributors within that proceeding and the positions taken by all parties in response. The Board's decision addressed the rate making and rate rider consequences of the evidence.

The Board's decision was also informed by the financial implications to the gas distributors in relation to cost of capital, working cash, income and now HST tax impacts borne by the distributors in having to carry gas in storage investments.

As a result, Enbridge does not believe it would be appropriate for the Board to consider any other method or period of time for clearance of the PGVA balance than that already heard within evidence and decided upon within the EB-2008-0106 proceeding. To do so would effectively amend the Board's decision.

Were the Board to decide that it would alter its approved methodology without re-examining and considering all implications of any such decision, the impacts within rates, rate riders, and related financial consequences to customers and gas distributors could result in consequences contrary to the findings of the Board's EB-2008-0106 proceeding.

If the Board was to consider a change or deferral of the clearance of the balances in the PGVA from what is the normal approved timing of clearance, the impact of such a change to the cash flow and changes in interest expense being incurred by the gas distributors in comparison to the Board's prescribed interest rates would have to be considered. The real carrying costs to EGD from recovering a very large PGVA balance over an extended time period are likely much higher than what results from the Board's prescribed interest rates. It is the Company's position that were the Board to give any of these alternatives consideration (and the Company does not support this), that the carrying costs associated with such balances must be valued at the Weighted Average Cost of Capital.

Please also see Enbridge's response to CME Interrogatory #4 found at Exhibit I, Tab 2, Schedule 4.

The table on page 4 of this exhibit provides the impacts on a typical residential customer's 2014 annual bill based on the proposed 1 year clearing as well as the impacts assuming the Rider C is recovered over a 2 year, 3 year, or 4 year period.
As can be seen, based on the 12 month clearing methodology, the Rider C accounts for 25% of the proposed 40% increase while the rate impact accounts for 15%. Recovering

Witnesses: J. Collier
K. Culbert
A. Kacicnik

the Rider C over 24 months results in a 10% reduction to the total annual bill. However, spreading the recovery over an increased period of time diminishes the amount of the Rider C proportion on the bill. Therefore, the impact on the total bill decrease as can be seen under the 36 and 48 month scenarios.

For the reasons discussed above, Enbridge does not agree with this approach but has provided the impacts as requested.

Furthermore, as it relates to this QRAM implementation, in order to have rates and Rider C billed to customer's on April 1, 2014, the Company would require a Board Decision approving the proposed rates, Rider C, and customer rate notices as proposed by the Company no later than March 28, 2014.

If the Board were to make any changes to the proposed rates or Rider C, the Company would be unable to have the revised rates or Rider C in place by April 1, 2014. The Company requires a two week lead time to test rates and upload rates into the billing system. The Company also requires one and half week lead time to prepare and have printed the customer rates notices. This coupled with the fact that the Company's rates and Rider C are designed on a 12 month basis would result in any change to Enbridge's proposed rates or Rider C being implemented with the July 1, 2014 QRAM.

Witnesses: J. Collier
K. Culbert
A. Kacicnik

RATE 1		Heating & Water Htg. 12 month Clearance			
		(A)	(B)	CHANGE (A) - (B)	%
VOLUME	m³	3,064	3,064	0	0%
CUSTOMER CHG.	$	240.00	240.00	0.00	0%
DISTRIBUTION CHG.	$	201.68	200.32	1.36	1%
LOAD BALANCING	$	181.59	181.66	(0.07)	0%
SALES COMMDTY	$	539.37	388.47	150.90	39%
ANNUAL BILL	$	1,162.64	1,010.45	152.19	15%
RIDER C	$	219.53	(26.96)	246.49	
ANNUAL BILL INCL RIDER C	$	1,382.17	983.49	398.68	40.5%

RATE 1		Heating & Water Htg. 24 month Clearance			
		(A)	(B)	CHANGE (A) - (B)	%
VOLUME	m³	3,064	3,064	0	0%
CUSTOMER CHG.	$	240.00	240.00	0.00	0%
DISTRIBUTION CHG.	$	201.68	200.32	1.36	1%
LOAD BALANCING	$	181.59	181.66	(0.07)	0%
SALES COMMDTY	$	539.37	388.47	150.90	39%
ANNUAL BILL	$	1,162.64	1,010.45	152.19	15%
RIDER C	$	109.77	(26.96)	136.73	
ANNUAL BILL INCL RIDER C	$	1,272.41	983.49	288.92	29.4%

RATE 1		Heating & Water Htg. 36 month Clearance			
		(A)	(B)	CHANGE (A) - (B)	%
VOLUME	m³	3,064	3,064	0	0%
CUSTOMER CHG.	$	240.00	240.00	0.00	0%
DISTRIBUTION CHG.	$	201.68	200.32	1.36	1%
LOAD BALANCING	$	181.59	181.66	(0.07)	0%
SALES COMMDTY	$	539.37	388.47	150.90	39%
ANNUAL BILL	$	1,162.64	1,010.45	152.19	15%
RIDER C	$	73.18	(26.96)	100.14	
ANNUAL BILL INCL RIDER C	$	1,235.82	983.49	252.33	25.7%

RATE 1		Heating & Water Htg. 48 month Clearance			
		(A)	(B)	CHANGE (A) - (B)	%
VOLUME	m³	3,064	3,064	0	0%
CUSTOMER CHG.	$	240.00	240.00	0.00	0%
DISTRIBUTION CHG.	$	201.68	200.32	1.36	1%
LOAD BALANCING	$	181.59	181.66	(0.07)	0%
SALES COMMDTY	$	539.37	388.47	150.90	39%
ANNUAL BILL	$	1,162.64	1,010.45	152.19	15%
RIDER C	$	54.88	(26.96)	81.84	
ANNUAL BILL INCL RIDER C	$	1,217.52	983.49	234.03	23.8%

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Witnesses: J. Collier
K. Culbert
A. Kacicnik

BOARD STAFF INTERROGATORY #4

INTERROGATORY

Ref: Exhibit Q2-2, Tab 1, Schedule 1, p. 6:

Enbridge noted that by locking in some supplies for the month of February through the monthly RFP process, it was able to temper the price impacts of what Enbridge paid for western Canadian supplies. Did Enbridge ever consider locking in all of the forecasted supply for the month of February through the monthly RFP process? Please explain the rationale for locking in some of the supply and not locking in all of its supply.

RESPONSE

When the Company issues an RFP it does not indicate the amount of supply it needs. The Company therefore gets proposals from all willing suppliers. Often, including in February, the volume from all proposals received will not meet the Company requirements which leaves it having to buy the remainder on the day.

In addition, during periods of price volatility suppliers may not be willing to take on the added risk of price exposure. The Company suspects they would only be willing to bear that risk if their supply is hedged either physically or financially (which will also increase its cost). Consequently, suppliers may not bid or may only offer supply based on a daily index. In February the majority of the supply responses received were based on a daily index. EGD still accepted these bids to eliminate the risk of not having the supply available however, these supplies did not eliminate the exposure to daily price volatility.

Witness: D. Small

BOARD STAFF INTERROGATORY #5

INTERROGATORY

Ref: Exhibit Q2-2, Tab 1, Schedule 1, paragraph 15:

Can you please confirm that the units in the table should be in $(000) as opposed to $(millions).

RESPONSE

The units in the table should be in $(000’s).

Witness: D. Small

BOARD STAFF INTERROGATORY #6

INTERROGATORY

Ref: Exhibit Q2-2, Tab 1, Schedule 1, paragraphs 10 and 15:

For the month of January 2014, the table in paragraph 10 shows a volumetric variance of 0.5 Bcf (1.5 Bcf minus 1.0 Bcf) between the 2014 Budget and 2014 Actual as it relates to peaking supplies. In paragraph 15, the purchase costs of peaking supplies for January 2014 show an increase of $ 71.4 million ($76.735 million minus $5.3506 million) between the 2014 Budget and 2014 Actual. Please explain why the peaking service volumes increased by about 50% while the costs increased by about 1334% in the month of January 2014.

RESPONSE

As described in response to Board Staff Interrogatory #1 found at Exhibit I, Tab 1, Schedule 1, the price payable for Peaking Service is based upon the Iroquois index on the day that the service is called upon. Because Peaking Service is intended to be used on peak or near peak conditions the applicable index will be based upon market demand on the day, which in the case of January 2014, was extremely high.

Witness: D. Small

BOARD STAFF INTERROGATORY #7

INTERROGATORY

Ref: Exhibit Q2-3, Tab 1, Schedule 2, p. 2:

The table on this page indicates “Variances to be Cleared in October 2013 QRAM”. Please confirm that this table should read “Variances to be Cleared in April 2014 QRAM”.

RESPONSE

The table should have read “Variances to be Cleared in April 2014 QRAM”.

Witness: D. Small

BOARD STAFF INTERROGATORY #8

INTERROGATORY

Please provide a table outlining, for the residential class, the gas supply charge and the adjusted gas supply charge from January 1, 2005 to Enbridge's current April 2014 QRAM application. Please also provide tables and/or graphs that compare gas cost and spot prices at AECO and Dawn from July 1, 2013 to March 1, 2014.

RESPONSE

Please see the table on the following page outlining the residential (Rate 1) gas supply charge and the adjusted gas supply charge from January 1, 2005 to April 1, 2014. As can be seen in the chart, the effective proposed April 1, 2014 gas supply charge inclusive of the Rider C commodity adjustment is well below the effective gas supply charges from 2005 to 2009.

In addition, as can be seen in the shaded areas, the increase in the effective gas supply charge from January 1, 2014 to March 1, 2014 is similar to the increase system gas customers experienced in the January 2010 to April 2010 and October 2005 to January 2006 time periods.

The Company would also like to highlight that the steady decline of commodity prices since 2007 has resulted in commodity costs becoming a relatively smaller proportion of the bill, hence, price movements relative to historical levels result in larger bill impacts. However, current Gas Supply charges remain well within historical norms.

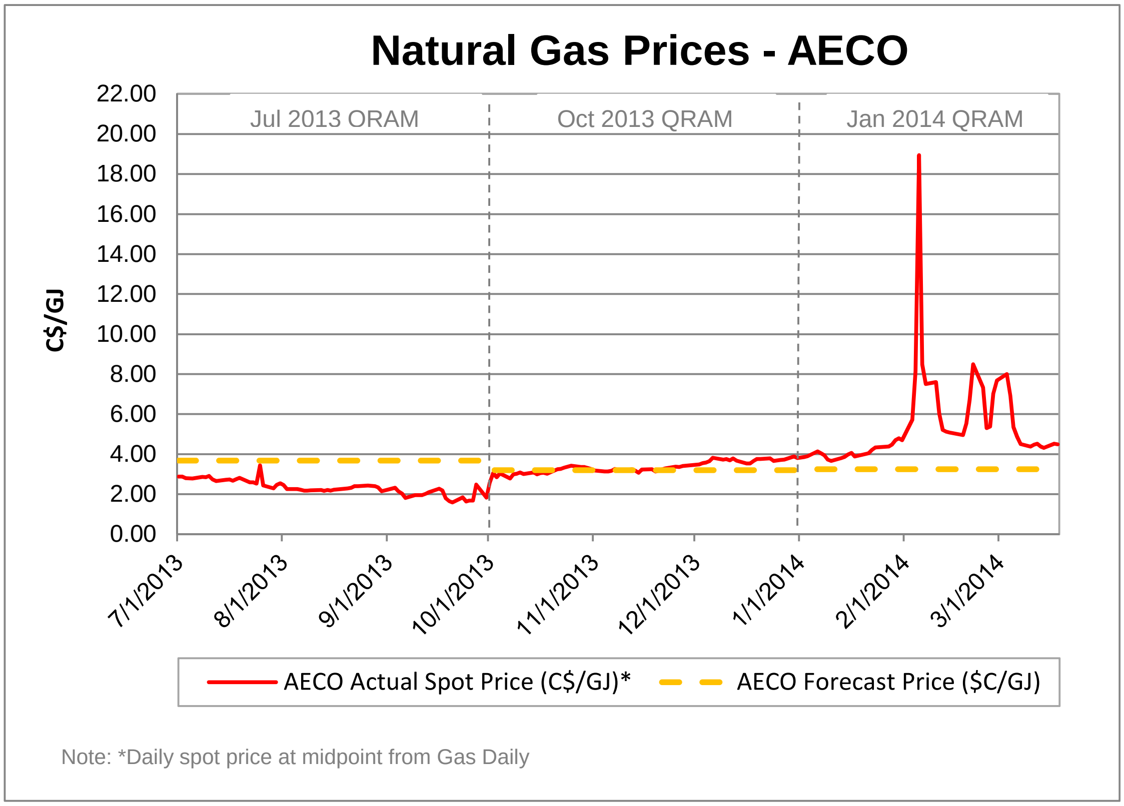
Witnesses: J. Collier
A. Kacicnik

QRAM	Gas Supply Charge (¢/m³)	Cost Adjustment (¢/m³)	Adjusted Gas Supply Charge (¢/m³)
Jan-05	31.0561	(1.2775)	29.7786
Apr-05	27.8006	(4.5113)	23.2893
Jul-05	31.0976	(4.1044)	26.9932
Oct-05	35.3252	(5.8558)	29.4694
Jan-06	43.1228	(1.9301)	41.1927
Apr-06	35.3960	(1.6354)	33.7606
Jul-06	34.0717	(6.2430)	27.8287
Oct-06	34.0717	(11.5645)	22.5072
Jan-07	31.4844	(0.8735)	30.6109
Apr-07	32.8599	(3.8645)	28.9954
Jul-07	32.8599	(6.6333)	26.2266
Oct-07	29.0978	(3.0868)	26.0110
Jan-08	26.7601	(2.2612)	24.4989
Apr-08	30.3556	(3.9604)	26.3952
Jul-08	39.0121	(0.8578)	38.1543
Oct-08	33.7551	1.7008	35.4559
Jan-09	30.3652	(1.2088)	29.1564
Apr-09	23.5363	(6.1615)	17.3748
Jul-09	20.4349	(5.7200)	14.7149
Oct-09	19.8615	(6.9075)	12.9540
Jan-10	19.9690	(7.0549)	12.9141
Apr-10	21.1631	(0.0460)	21.1171
Jul-10	17.2987	(1.0873)	16.2114
Oct-10	15.4224	(1.6406)	13.7818
Jan-11	14.4229	(2.1734)	12.2495
Apr-11	13.9780	(2.1653)	11.8127
Jul-11	14.9268	(1.8462)	13.0806
Oct-11	13.6891	(1.4607)	12.2284
Jan-12	11.8492	(0.7036)	11.1456
Apr-12	9.4150	(1.3502)	8.0648
Jul-12	9.8460	(1.3724)	8.4736
Oct-12	10.7186	(1.9119)	8.8067
Jan-13	12.8548	(2.1245)	10.7303
Apr-13	12.1485	(1.8514)	10.2971
Jul-13	14.0017	(1.0981)	12.9036
Oct-13	12.3038	(0.8424)	11.4614
Jan-14	12.6789	(0.9377)	11.7412
Apr-14	17.6031	3.2613	20.8644

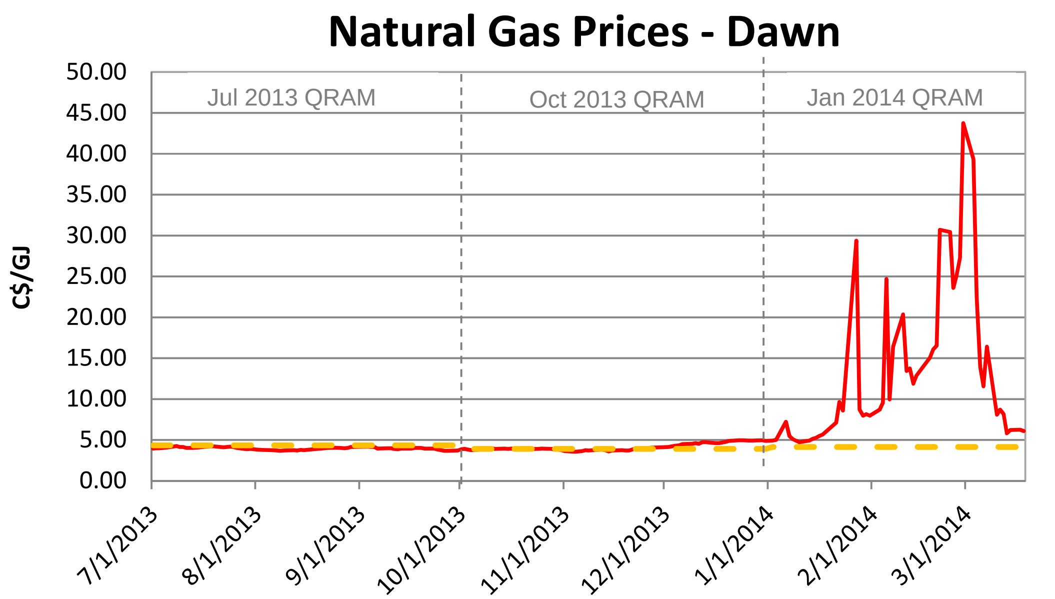
Witnesses: J. Collier
A. Kacicnik

Please see below the graphs that compare forecast natural gas prices and actual natural gas spot prices at AECO and Dawn from July 1, 2013 to March 18, 2014.

Please note, Enbridge has extended the graphs up to and including the March 18, 2014 to illustrate that natural gas prices at AECO and Dawn for the month of March 2014 are trending downward to the AECO and Dawn forecast prices for that period.



Witnesses: J. Collier
A. Kacicnik



Note: *Daily Dawn spot price (US$/MMBtu) at midpoint from Gas Daily
Daily exchange rate (U.S. Dollar Noon) conversion from the Bank of Canada

Witnesses: J. Collier
A. Kacicnik

BOARD STAFF INTERROGATORY #9

INTERROGATORY

Please confirm that Enbridge does not profit (or loss) on the commodity cost of natural gas.

RESPONSE

Correct. Enbridge does not profit on the commodity cost of gas.

Witness: D.Small

BOARD STAFF INTERROGATORY #10

INTERROGATORY

Has Enbridge received any letters of comments to date regarding its April 2014 QRAM application? If so, has Enbridge responded to any of those letter of comments? Board staff requests that Enbridge file those responses with the Board Secretary's Office.

RESPONSE

Enbridge has only received one letter regarding its April 2014 QRAM application. The same letter was also copied to the Ontario Energy Board. Enbridge responded by way of a follow up phone call explaining the reasons for the increase as well as the Company's support of initiatives such as the Green Saver program and LEAP.

The Company's Ombudsmen's office has also received seven other inquiries (calls and emails), and the call centre has also received a few inquiries. The Company's practice is to explain the reasons for the changes, the QRAM process, and the fact that commodity costs are passed through without markup.

Witness: M. Lister

CME INTERROGATORY #1

INTERROGATORY

Please provide a list of benchmarks which are available to assist the Board and interested parties in evaluating the prudence of EGD's gas buying and transportation usage and procurement during the January 1, 2014 to March 31, 2014 cold snap.

RESPONSE

The benchmark available to evaluate the Company's procurement is the gas supply plan established for the purposes of developing its gas cost budget. The gas supply plan has two components – the planning methodology that determines projected demand and a portfolio of assets to meet the projected demand. The benchmark for managing its gas supply activities in the 2013 / 2014 winter is the 2014 gas supply plan approved by the Ontario Energy Board (the "Board") on an interim basis in the EB-2012-0459 rates case, where the Company brought forward a plan to displace short term firm transportation with annual firm transportation on TransCanada with a certain level of budgeted unutilized demand.

The Gas Supply Planning Methodology

There are two major elements which underpin the development of the gas supply planning methodology. The first involves the determination of peak day demand and second, the distribution of weather and specifically when peak day occurs. In EBRO 490 the Company proposed to alter its design criteria from a one in four recurrence interval (or coldest over a four year period) to a one in five recurrence interval both based on a normal distribution. Under this proposal peak day degree days would increase from 39.0 to 39.5 for the Central Weather Zone. The Company also proposed the adoption of a "multi-peak" design criteria. Under this proposal, the Company modeled a number of cold days distributed over the winter with the coldest day occurring in January and 17 other cold days distributed over the winter. The multipeak methodology allowed the Company to manage its storage targets throughout the winter to meet projected demand and retain deliverability to meet multipeak requirements. While the higher peak degree days resulted in higher costs, the multi-peak design criteria resulted in cost savings to customers in terms of storage space and inventory since it allowed for peak storage deliverability through until the end of January with declining deliverability through February and March. In its evidence the Company highlighted that this approach would result in higher delivered supplies in colder than normal years. In its Decision approving both proposals, the Board recognized the multi-peak design criteria as a “more sophisticated and superior approach.”

Subsequently, in EB-2011-0354, EGD applied for an update to its design criteria, after highlighting to the Board and intervenors in the preceeding three years that it had a significant concern about the riskiness of the Company’s design criteria and the components of its gas supply plan and the potential that the Company could experience customer outages if it was not rectified. The design criteria update requested a one in ten recurrence interval based on a log-normal distribution. Under this proposal the peak day design criteria would increase from 39.5 degree days for the Central Weather Zone to 43.7 degree days for the Central Weather Zone. It was recognized at the time that the move to a one in ten design criteria would entail an increase in cost and unutilized demand charges as a result of the increased transportation requirement stemming from the requested change. The Company and interveners were able to come to an agreement on the design criteria and ultimately settled the issue leading to the adoption of a one in five recurrence interval based on a log-normal distribution. The Settlement Agreement in EB-2010-0354 specified a phased in approach for the design criteria such that peak day degree days for the Central Weather Zone would increase from 39.5 to 40.4 in 2013 and to 41.4 in 2014[1]. The 2014 gas supply plan approved on an interim basis by the Board utilized the updated design criteria agreed to in EB-2011-0354.

The update request did not seek a change to the multi-peak aspect of the design criteria to assume a different distribution of cold days (for example peak day occurrence at the end of winter that would allow the Company to maintain more space or inventory and hence higher deliverability and reduced reliance on delivered supply), but rather focused on updating the weather conditions, or degree days, assumed for each multi-peak, including peak day for four reasons. First, the increase in design day allowed the Company to increase the transportation assets in its portfolio hence providing added flexibility to meet a different distribution of demand through the winter. Secondly, the multipeak methodology has worked well for the Company and there was insufficient evidence to justify a change to a different distribution of weather. Thirdly, the Company had witnessed a significant growth in liquidity at Dawn and had no reason to doubt that increased reliance on delivered supply at Dawn would be available if needed, albeit at market prices. Finally, the Company was cognizant of the need to manage rate impacts on customers. Acquiring additional storage to meet a different distribution of cold days would strand deliverability in the absence of an infrastructure solution such as the GTA Project and holding higher inventories with same amount of storage space would result

[1] For simplicity peak day design criteria for the Central Weather Zone are discussed as this is the largest consuming area in the Enbridge franchise. Complete details on the design criteria currently in use can be found in EB-20110354 at Exhibit D1, Tab 2, Schedule 3. Details of the phased in approach can be found in the Settlement Agreement relating to the same hearing.

in pricing exposure to delivered supply in any event, due the need to procure these supplies in the winter.

The most recent experience to date shows, as of March 18th, 2014, this winter has been the coldest in the last 25 years and the 3rd coldest on record since 1954[2]. It is expected that once March is complete this past winter will have been the coldest on record since 1954. In contrast, as outlined above the Company requested a one in ten planning criteria in EB-2012-0459, settled for an enhanced one in five planning criteria, and was able to implement the incremental transportation arrangements resulting from this enhancement in November 2013.

Components of the Gas Supply Plan

EGD develops a cost effective gas supply plan to meet its one in five planning criteria on the principles of diversity, flexibility, and reliability in order to meet peak day demand and demand throughout the year. Based on these principles the gas supply plan is composed of various long haul and short haul transportation contracts which provide access to various production basins and storage facilities at Tecumseh and Dawn. Also included are delivered supplies at Dawn, peaking supplies and curtailment which are utilized to meet seasonal, near peak, and peak day demands. The transportation and storage assets are the lower cost components on a per unit basis with high firm annual fixed payment commitments, while delivered supply, peaking, and curtailment are higher unit cost but more flexible components of its plan. The lower cost assets are maximized first when actual demand exceeds projected demand. As noted above, since the Company's portfolio is sized for a one in five recurrence, the Company had no choice but to use the higher cost tools of delivered supplies, peaking supplies, and curtailment to meet the projected one in sixty winter it is faced with. The Company's exposure to daily / intramonth market pricing is driven by its plan requirement to manage purchases to meet projected demand and storage deliverability targets. The volumetric and financial impacts of the recent cold weather experience can be found at Exhibit Q2-2, Tab 1, Schedule 1, page 5 of 10.

EGD has taken a number of proactive steps to ensure the continued safe, reliable and cost effective delivery of natural gas to its customers. These include: the increased use of firm transportation over unsecured arrangements through the System Reliability proceeding (EB-2010-0231), the update to design criteria (EB-2011-0354), and the GTA Project Leave to Construct application (EB-2012-0451). The GTA Project will provide further benefits by allowing the Company to diversify supply and eliminate the use of peaking supplies in the Enbridge CDA.

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[2] Weather statistics refer to the Enbridge Central Weather Zone. Data from 1954 onwards are used as this comprises the complete degree day history available.

EGD recognizes there is a trade off in terms of cost with respect to more conservative versus less conservative gas supply planning assumptions. If the procurement of additional, unplanned supplies during colder than expected winters is and will remain a concern for the Board and interested parties, EGD would suggest that different, and perhaps more conservative gas supply planning assumptions be utilized.

The Company is willing to investigate other, more conservative assumptions, to utilize when developing its gas supply plan. For example, the inclusion of a higher design criteria such as that originally proposed in EB-2011-0354 and / or the requirement that storage deliverability remain at a level such that peak day demand can be supplied as late as March 1st would tend to mitigate the amount of discretionary purchases required during a winter such as that recently experienced. Another option would be to carry additional storage capacity as a contingency. EGD would note that these suggested planning assumptions are similar to the gas supply planning parameters utilized by Union Gas and would mitigate the cost consequences of meeting a winter colder than that assumed with 1 in 5 gas supply plan.

CME INTERROGATORY #2

INTERROGATORY

Without limiting the generality of the previous question, please provide the following information:

(a) What is the maximum daily curtailability available to EGD under the auspices of its interruptible contract arrangements and, on a day-to-day basis during the cold snap, to what extent did EGD utilize that curtailability?

(b) What factors determined the actual sources of gas supply which EGD relied upon during the cold snap compared to the sources reflected in EGD's budget? For example, as shown in the response to question 10 in Exhibit Q2-2, Tab 1, Schedule 1, pages 4 and 5, "Chicago Supply" was budgeted to be the source of about 295.6 106 m3 of supply. However, on an actual basis, a volume less than the budgeted amount was acquired from that source, namely about 279.0 106 m3. The actual cost information provided in the response to question 15 in that Exhibit indicates that the average cost in February for "Chicago Supply" was about $352.6 106 m3. In contrast, the average cost of "Delivered Supply" purchased in February in amounts greatly in excess of the budgeted volumes was in the order of $769.0 106 m3. This information raises the obvious question of why an amount of "Chicago Supply" less than that budgeted was replaced with "Delivered Supply" costing substantially more.

(c) Similarly, the evidence in response to questions 10 and 15 in Exhibit Q2-2, Tab 1 indicates that the actual cost of "Peaking Supply" in January and February 2014 was in order of $1,845 106 m3 for January and $1,564 106 m3 for February. Are these prices something that EGD contracts for in advance of a winter season? If so, then on what basis are the extremely high contractual prices rationalized? If these are "market" prices which are not determined in advance under the provisions of a contract, then please explain how that "Peaking Supply" market operates to produce such high prices?

(d) What is the actual average landed cost per GJ of each of the budgeted and incremental supplies purchased by EGD in January and February 2014? What sources of information are available to determine how EGD's actual costs of these budgeted and incremental supplies compare to the actual costs of budgeted and incremental supplies incurred by other distributors in the same period?

Witness: D. Small

RESPONSE

a) The level of curtailment is based upon the Contract Demand of those customers who have entered into interruptible contracts. The Company assumes for planning purposes that 75% of the Contract Demand is the amount of demand being avoided by interrupting those customers. The total Contract Demand for both the Rate 145 and Rate 170 customers is 5,838.0 10^3 m^3 therefore the Company expects a reduction in demand of 4,378 10^3 m^3 or approximately 165,000 GJ/day when all of the interruptible customers are asked to curtail.

   The attached table identifies the dates when curtailment was called this past winter up until March 17, 2014.

b) The level of Vector capacity contracted by the Company is required to transport volumes purchased in Alberta and received from the Alliance pipeline as well as volumes purchased in Chicago. The volume received from Alliance can fluctuate on a daily basis dependent upon the level of Authorized Overrun Service ("AOS") available on Alliance which influences the amount of gas purchased in Alberta. Therefore, the volume purchased in Chicago can vary depending upon the level of AOS. The budget for 2014 assumed a level of AOS which impacted the forecast of Chicago purchases. In the actual results a higher level of purchases in Alberta, because of higher AOS on Alliance, translated into lower purchases in Chicago.

   Lower purchases in Chicago did not translate into higher Delivered Supply.

c) As part of the budget process the Company forecasts the Peak Day Demand under Design conditions and determines how to satisfy that Peak Day demand including the acquisition of Peaking Service. To facilitate the contracting for this service the Company sends out an RFP to potential suppliers. Bids for this service include a Demand Charge and a Commodity charge. While the Demand Charge is fixed the Commodity Charge is variable and is typically tied to the Iroquois daily price index. When the Company nominates for Peaking Service there is an obligation on behalf of the supplier to deliver the gas to EGD and the obligation on the Company will be to pay whatever is the publically traded price for that day. The commodity price for this supply is driven by the market price on the day.

Witness: D. Small

d) The budgeted purchase cost for the months of January and February were based upon the volumes underpinning the 2014 gas supply plan priced at a forecast of future prices based upon a 21 day average for the period November 1, 2013 to November 29, 2013 which is the period that the January 1, 2014 QRAM was based on. The average actual cost payable by the Company is based upon an average of monthly and daily prices experienced in the market place over the two months in question. (Please see table below.)

	as per January 2014 QRAM				Actuals	Estimate	
$/GJ	January	February			January	February	
Nova Supplies	3.232	3.220			3.861	6.942	
Empress Supplies	3.217	3.207			4.104	6.506	
Alliance Supplies	3.400	3.385			3.965	6.143	
Peaking Supplies	5.087	5.451			48.164	41.526	
Chicago Supplies	3.805	3.812			5.663	9.203	
Delivered Supplies	4.379	4.395			6.759	20.078	

Each individual distributor will purchase gas from suppliers at various delivery points dependent upon their individual customer demands and dependent on the level of transportation and storage contracts that they have available. All gas acquired from suppliers will be based upon the market index for that specific delivery point either at a monthly or daily unit price depending upon the terms on which the gas was acquired.

In order to do a price comparison between individual distributors it is necessary to understand the nuances of the individual distributors' purchases.

DELIVERY AREA	RATE	CURTAILMENT START DATE & TIME	CURTAILMENT END DATE & TIME	# OF CURTAILED DAYS	Curtailment Delivered Supply (CDS)	
CDA	145-16	Dec.15-2013 09:00	Dec.17-2013 09:00	3	CDS allowed	CDS allowed Dec 15 & Dec 16 only
CDA	170-4	Dec.14-2013 21:00	Dec.17-2013 09:00	4	CDS allowed	CDS allowed Dec 15 & Dec 16 only
EDA	170-4	Dec.14-2013 21:00	Dec.17-2013 09:00	4	CDS allowed	CDS allowed Dec. 15 & Dec 16 only
EDA	145-16	Dec.15-2013 9:00	Dec.17-2013 9:00	3	CDS allowed	CDS allowed Dec. 15 & Dec 16 only
EDA	145-16	Dec.30-2013 10:00	Jan. 4, 2014 10:00	5	No CDS	
EDA	170-4	Dec.30-2013 10:00	Jan. 4, 2014 10:00	5	No CDS	
CDA	145-16	Jan.2-2014 10:00	Jan.4-2014 10:00	2	No CDS	
CDA	170-4	Jan.2-2014 10:00	Jan.4-2014 10:00	2	No CDS	
CDA	145-16	Jan.6-2014 10:00	Jan.8-2014 10:00	2	CDS allowed	
CDA	170-4	Jan.6-2014 10:00	Jan.8-2014 10:00	2	CDS allowed	
CDA	145-16	Jan.8-2014 10:00	Jan. 9-2014 10:00	1	CDS allowed	
CDA	170-4	Jan.8-2014 10:00	Jan. 9-2014 10:00	1	CDS allowed	
CDA	170-4	Jan.20-2014 10:00	Jan.23-2014 10:00	3	CDS allowed	
CDA	145-16	Jan.20-2014 10:00	Jan.23-2014 10:00	3	No CDS	
EDA	170-4	Jan.20-2014 10:00	Jan.23-2014 10:00	3	No CDS	
EDA	145-16	Jan.20-2014 10:00	Jan.23-2014 10:00	3	No CDS	
CDA	170-4	Jan.23-2014 10:00	Jan. 24-2014 10:00	1	CDS allowed	
CDA	145-16	Jan.23-2014 10:00	Jan. 24-2014 10:00	1	CDS allowed	
EDA	170-4	Jan.23-2014 10:00	Jan. 24-2014 10:00	1	No CDS	
EDA	145-16	Jan.23-2014 10:00	Jan. 24-2014 10:00	1	No CDS	
CDA	170-4	Feb. 25-2014-10:00	Mar.01-2014-10:00	4	CDS allowed	
CDA	145-16	Feb. 25-2014-10:00	Mar.01-2014-10:00	4	CDS allowed	
EDA	170-4	Feb. 25-2014-10:00	Mar.01-2014-10:00	4	CDS allowed	
EDA	145-16	Feb. 25-2014-10:00	Mar.01-2014-10:00	4	CDS allowed	
CDA	170-4	Mar. 3-2014-10:00	Mar. 5-2014-10:00	2	CDS allowed	
CDA	145-16	Mar. 3-2014-10:00	Mar. 5-2014-10:00	2	CDS allowed	
EDA	170-4	Mar. 3-2014-10:00	Mar. 5-2014-10:00	2	CDS allowed	
EDA	145-16	Mar. 3-2014-10:00	Mar. 5-2014-10:00	2	CDS allowed	
CDA	170-4	Mar. 15-2014-10:00	Mar. 18-2014-10:00	3	CDS allowed	in the delivery area or at Dawn
CDA	145-16	Mar. 15-2014-10:00	Mar. 18-2014-10:00	3	CDS allowed	in the delivery area or at Dawn
EDA	170-4	Mar. 15-2014-10:00	Mar. 18-2014-10:00	3	CDS allowed	in the delivery area or at Dawn
EDA	145-16	Mar. 15-2014-10:00	Mar. 18-2014-10:00	3	CDS allowed	in the delivery area or at Dawn

CME INTERROGATORY #3

INTERROGATORY

The evidence indicates that, for system gas users, the total annual bill impact of the combined effect of the gas cost increases and Purchased Gas Variance Account ("PGVA") clearances which EGD is asking the Board to approve in this QRAM Application will materially exceed 10%. Is this conclusion correct? If so, then, for system gas users in each rate class, please provide the annual bill impact of the combined effect of the gas cost increases and PGVA clearances which EGD is asking the Board to approve.

RESPONSE

Yes, the impacts of this QRAM Application will exceed 10% on a total bill basis. Please find below the sample system gas customer's annual bill impacts for each rate class showing the annual bill impacts of the combined effects of gas cost increases and PGVA clearances.

The April 1, 2014 bill impacts include the effects from the proposed change in rates and proposed change in Rider C (PGVA clearance) relative to the January 1, 2014 QRAM rates and January 1, 2014 Rider C, both of which were approved as part of the January 1, 2014, QRAM application (EB-2013-0406).

While the Company acknowledges the bill impacts, Enbridge would like to note that it completely adheres to the QRAM process as prescribed in the QRAM guidelines as filed at Exhibit Q2-1, Tab 2, Schedule 1, Appendix A. As part of the eight principles listed on page 1 of Appendix A, the QRAM process is intended to reflect market prices, enhance price transparency, and provide fairness and equity among all customer groups. Altering the forecast price of natural gas or proposed clearance of the PGVA could distort market pricing and price transparency and could diminish the price transparency between system gas supply and direct purchase market offerings which in turn could lead to customer confusion in the marketplace.

The Company would also like to note that direct purchase customers have also likely been impacted by the changes in commodity rates and sustained cold temperatures. Without knowing the purchasing and contracting practices of large volume customers on direct purchase, the Company can only assume that they were also required to pay for increased supplies at significant price increases similar to EGD over the past winter season. Mitigating the impact of the recovery of EGD's increased costs for EGD's large volume system gas customers through rate smoothing or rider smoothing could cause

Witnesses: J. Collier
A. Kacicnik

an unfair advantage amongst large volume customers on direct purchase versus system gas. (Please note that a small percentage of EGD's large volume customers are on system gas, this can be seen at Exhibit Q2-3, Tab 3, Schedule 4, page 1 when comparing annual sales volumes by rate class to annual deliveries volumes by rate class.)

Total annual bill impact of the combined effect of the gas cost changes and PGVA clearances for system gas customers

(A) April 1, 2014 Rates vs (B) January 1, 2014 Rates

RATE 1 — Heating & Water Htg.

		(A)	(B)	CHANGE (A) - (B)	%
VOLUME	m³	3,064	3,064	0	0%
CUSTOMER CHG.	$	240.00	240.00	0.00	0%
DISTRIBUTION CHG.	$	201.68	200.32	1.36	1%
LOAD BALANCING	$	181.59	181.66	(0.07)	0%
SALES COMMDTY	$	539.37	388.47	150.90	39%
ANNUAL BILL	$	1,162.64	1,010.45	152.19	15%
RIDER C	$	219.53	(26.96)	246.49	
ANNUAL BILL INCL RIDER C	$	1,382.17	983.49	398.68	40.5%

RATE 1 — Heating & Water Htg.

		(A)	(B)	CHANGE (A) - (B)	%
VOLUME	m³	2,480	2,480	0	0%
CUSTOMER CHG.	$	240.00	240.00	0.00	0%
DISTRIBUTION CHG.	$	164.69	163.59	1.10	1%
LOAD BALANCING	$	146.96	147.05	(0.09)	0%
SALES COMMDTY	$	436.55	314.42	122.13	39%
ANNUAL BILL	$	988.20	865.06	123.14	14%
RIDER C	$	177.69	(21.82)	199.51	
ANNUAL BILL INCL RIDER C	$	1,165.89	843.24	322.65	38.3%

RATE 6 — Commercial Heating & Other Uses

		(A)	(B)	CHANGE (A) - (B)	%
VOLUME	m³	22,606	22,606	0	0%
CUSTOMER CHG.	$	840.00	840.00	0.00	0%
DISTRIBUTION CHG.	$	1,269.81	1,256.00	13.81	1%
LOAD BALANCING	$	1,300.65	1,302.28	(1.63)	0%
SALES COMMDTY	$	3,987.72	2,874.54	1,113.18	39%
ANNUAL BILL	$	7,398.18	6,272.82	1,125.36	18%
RIDER C	$	1,559.95	(194.86)	1,754.81	
ANNUAL BILL INCL RIDER C	$	8,958.13	6,077.96	2,880.17	47.4%

RATE 6 — Medium Commercial Customer

		(A)	(B)	CHANGE (A) - (B)	%
VOLUME	m³	169,563	169,563	0	0%
CUSTOMER CHG.	$	840.00	840.00	0.00	0%
DISTRIBUTION CHG.	$	6,838.12	6,763.58	74.54	1%
LOAD BALANCING	$	9,755.89	9,768.35	(12.46)	0%
SALES COMMDTY	$	29,911.09	21,561.48	8,349.61	39%
ANNUAL BILL	$	47,345.10	38,933.41	8,411.69	22%
RIDER C	$	11,700.86	(1,461.63)	13,162.50	
ANNUAL BILL INCL RIDER C		59,045.96	37,471.78	21,574.19	57.6%

RATE 100 — Small Industrial Firm

		(A)	(B)	CHANGE (A) - (B)	%
VOLUME	m³	339,188	339,188	0	0%
CUSTOMER CHG.	$	1,464.12	1,464.12	0.00	0%
DISTRIBUTION CHG.	$	17,936.71	17,865.02	71.69	0%
LOAD BALANCING	$	18,534.64	18,629.09	(94.46)	-1%
SALES COMMDTY	$	59,211.64	42,682.83	16,528.81	39%
ANNUAL BILL	$	97,147.11	80,641.06	16,506.04	20%
RIDER C	$	23,406.01	(2,923.80)	26,329.81	
ANNUAL BILL INCL RIDER C	$	120,553.11	77,717.26	42,835.85	55.1%

RATE 110 — Small Ind. Firm - 50% LF

		(A)	(B)	CHANGE (A) - (B)	%
VOLUME	m³	598,568	598,568	0	0%
CUSTOMER CHG.	$	7,048.44	7,048.44	0.00	0%
DISTRIBUTION CHG.	$	12,903.39	12,592.37	311.02	2%
LOAD BALANCING	$	30,355.82	30,695.20	(339.38)	-1%
SALES COMMDTY	$	104,972.66	75,497.98	29,474.68	39%
ANNUAL BILL	$	155,280.31	125,833.99	29,446.32	23%
RIDER C	$	22,209.87	(7,828.07)	30,037.94	
ANNUAL BILL INCL RIDER C	$	177,490.18	118,005.92	59,484.26	50.4%

RATE 115 — Rate 115 - Large Ind. Firm - 80% LF

		(A)	(B)	CHANGE (A) - (B)	%
VOLUME	m³	69,832,850	69,832,850	0	0%
CUSTOMER CHG.	$	7,471.44	7,471.44	0.00	0%
DISTRIBUTION CHG.	$	826,559.49	792,693.47	33,866.02	4%
LOAD BALANCING	$	3,460,029.88	3,504,667.40	(44,637.52)	-1%
SALES COMMDTY	$	12,246,796.41	8,808,087.20	3,438,709.21	39%
ANNUAL BILL	$	16,540,857.22	13,112,919.51	3,427,937.71	26%
RIDER C	$	2,261,676.51	(967,115.14)	3,228,791.65	
ANNUAL BILL INCL RIDER C	$	18,802,533.73	12,145,804.37	6,656,729.36	54.8%

RATE 135 — Seasonal Firm

		(A)	(B)	CHANGE (A) - (B)	%
VOLUME	m³	598,567	598,567	0	0%
CUSTOMER CHG.	$	1,380.96	1,380.96	0.00	0%
DISTRIBUTION CHG.	$	8,337.18	8,047.18	290.00	4%
LOAD BALANCING	$	24,278.17	24,685.26	(407.09)	-2%
SALES COMMDTY	$	105,346.00	75,870.76	29,475.24	39%
ANNUAL BILL	$	139,342.31	109,984.16	29,358.15	27%
RIDER C	$	17,711.60	(8,712.74)	26,424.34	
ANNUAL BILL INCL RIDER C	$	157,053.90	101,271.42	55,782.49	55.1%

RATE 145 — Small Industrial Interr.

		(A)	(B)	CHANGE (A) - (B)	%
VOLUME	m³	339,188	339,188	0	0%
CUSTOMER CHG.	$	1,480.08	1,480.08	0.00	0%
DISTRIBUTION CHG.	$	10,334.86	10,071.26	263.60	3%
LOAD BALANCING	$	15,525.53	15,643.34	(117.81)	-1%
SALES COMMDTY	$	59,881.60	43,179.31	16,702.29	39%
TOTAL SALES	$	87,222.07	70,373.99	16,848.08	24%
RIDER C	$	17,292.82	(3,542.48)	20,835.30	
ANNUAL BILL INCL RIDER C	$	104,514.89	66,831.51	37,683.38	56.4%

RATE 170 — Average Ind. Interr. - 75% LF

		(A)	(B)	CHANGE (A) - (B)	%
VOLUME		9,976,120	9,976,120	0	0%
CUSTOMER CHG.		3,351.72	3,351.72	0.00	0%
DISTRIBUTION CHG.		72,513.28	66,995.66	5,517.62	8%
LOAD BALANCING		381,047.00	385,997.09	(4,950.09)	-1%
SALES COMMDTY		1,749,542.10	1,258,297.98	491,244.12	39%
ANNUAL BILL		2,206,454.10	1,714,642.45	491,811.65	29%
RIDER C		401,229.57	(131,475.29)	532,704.86	
ANNUAL BILL INCL RIDER C		2,607,683.67	1,583,167.17	1,024,516.51	64.7%

Witnesses: J. Collier
A. Kacicnik

CME INTERROGATORY #4

INTERROGATORY

What “rate shock” mitigation measures, if any, did EGD consider, having regard to the Board’s prior precedent decisions to the effect that such measures should be considered when a utility proposes rate increases which will produce an annual bill increase in excess of 10%?

RESPONSE

The Company does not understand that the Ontario Energy Board (the “Board”) has any specific policy related to required “rate shock” mitigation measures for gas utilities.

EGD does understand that the Board requires electric utilities to “consider” mitigation where total bill increases for any customer class exceed 10% (see the Renewed Regulatory Framework (“RRF”) Report for Electricity at page 23) but notes that the Board’s description of that policy within the RRFE relates to utilities’ capital and O&M expenditures to ensure those expenditures are paced and prioritized in a manner such that costs are smoothed over the long term.

The Company does not employ any rate mitigation measures as it relates to the rate changes stemming from a QRAM application. The QRAM process prescribed in the Board’s Decision within the EB-2008-0106 Methodologies for Commodity Pricing, Load Balancing and Cost Allocation for Natural Gas Distributors proceeding is designed to flow through price changes to customers on a timely basis. The QRAM process facilitates current market pricing signals and enhances price transparency which facilitates market offerings and allows for a differentiation between system gas and direct purchase options.

In the current April 1, 2014 QRAM case, EGD did not consider that rate mitigation measures are appropriate, and therefore has made no proposal. An approach that spreads the impact of the gas cost increases over time could cause intergeneration equity issues, and could result in customers paying somewhat significant carrying costs. The QRAM process provides that updated gas costs be passed on to customers on a rolling basis in a mechanistic fashion. EGD has employed that approach within this application.

Please also see EGD’s response to Board Staff Interrogatory #3 found at Exhibit I, Tab 1, Schedule 3.

Witnesses: J. Collier
A. Kacicnik

CME INTERROGATORY #5

INTERROGATORY

In EGD's Application for rates for the years 2014 to 2018, evidence has been filed which indicates that EGD's 2013 Rates are too high by an amount in the order of $37M. Assuming that the Board may wish to take these 2013 normalized over-earnings into account when considering ways in which the rate increases being requested in this QRAM Application might be mitigated, please provide an exhibit which will show how the amount of $37M of 2013 over-earnings would be allocated to each rate class, assuming that a Rate Base responsibility factor is used to allocate the amount.

RESPONSE

EGD's actual and normalized earnings during any fiscal year are not influenced by variances that occur between EGD's actual versus forecast natural gas reference prices.

By extension, EGD's 2013 normalized earnings and any interpretation of 2013 rates being too high (which EGD does not accept), is not the result of any implication or any difference between the actual versus forecast natural gas reference prices throughout 2013.

The 2013 rates and earnings results include the impacts of Decisions by the Ontario Energy Board (the "Board") for all 2013 Quarterly Rate Adjustment Mechanism ("QRAM") proceedings, which include a structured and mechanistically developed forecast price for natural gas.

Additionally, the Purchased Gas Variance Account ("PGVA") mechanism and required rate rider credits or debits, approved in Decisions by the Board within each QRAM proceeding, are used to record and clear differences between actual natural gas prices versus those that were forecast for inclusion in forward looking rates.

In the Company's view, there is no, nor has there ever been, Board policy which applies prior year earnings to offset future year costs. The Company believes that any changes that alter either the treatment of Gas Costs or the treatment of prior year's earnings would have a fundamental and profound effect on the Company's risk profile. It could also amount to retroactive ratemaking.

Witness: K. Culbert

The Company completely adheres to the Board's Decision within the EB-2008-0106 Methodologies for Commodity Pricing, Load Balancing and Cost Allocation for Natural Gas Distributors proceeding, for determining the natural gas reference price to be used within rates through the QRAM process and the method to be used for the derivation and clearance of the PGVA. Consequently, the Company respectfully declines to provide the information requested as it is not relevant information within the required QRAM process.

IGUA INTERROGATORY #1

INTERROGATORY

At Exhibit Q2-2, Tab 1, Schedule 1, pp 4-5, paragraph 10, EGD explains that if the company had not curtailed its curtailable delivery customers, it would have needed to buy an additional 66.1 $10^6 m^3$ at a cost of $25 million. Understanding the cost of the curtailment (ie. the amount paid by EGD to the curtailed customers to buy the customers' gas in order for EGD to meet its gas supply requirements) would be helpful.

RESPONSE

As per the Rate Handbook in this proceeding (Exhibit Q2-3, Tab 4, Schedule 7, Handbook page 28):

> … if the applicant is supplying its own gas requirements, the gas delivered by the Applicant during the period of curtailment shall be purchased by the Company for the Company's use. The purchase price for such gas will be equal to the price that is reported for the month, in the first issue of the *Natural Gas Market Report* published by Canadian Enerdata Ltd. during the month, as the "current" "Avg" (i.e., average) "Alberta One-Month Firm Spot Prices" for "AECO 'C' and Nova Inventory Transfer" in the table entitled "Domestic spot gas price", adjusted for AECO to Empress transportation tolls and compressor fuel costs."

The price payable in January 2014 and February 2014 is $0.15/$10^3$ m^3 and $0.17/$10^3$ m^3, respectively which equates to approximately $10.0 million paid to curtailable delivery customers for their gas. Curtailable delivery customers are also paid the Seasonal Credit a total of $7.1 million payable annually whether or not curtailment is called. The Annual Seasonal Credit is a dollar amount provided to those customers who have chosen to accept the terms of the interruptible rates.

The reference in the evidence to buying an additional 66.1 10^6 m^3 at a cost of $25 million was an attempt to demonstrate the incremental cost that the Company may have incurred if the interruptible customer did not curtail forcing the Company to purchase additional volumes.

Witness: D. Small

IGUA INTERROGATORY #2

INTERROGATORY

Enbridge has included in the PGVA an amount of $4.2 million for extraction revenue for the period Apr/13 - Nov/13. It is recorded as a reduction to purchased gas costs. In the last ORAM [EB-2013-0406, Exhibit I, Tab 1, Schedule 2] EGD indicated in response to a question from OEB Staff that it was prepared to report extraction revenues separately as follows: (i) in a paragraph in the written evidence and (ii) in the schedule showing the components of the PGVA, indicating the level of extraction revenue for each month. In the instant ORAM, EGD has included information on total extraction revenues in the written evidence at Exhibit Q2-2 , Tab 1, Schedule 1, p. 8, paragraph 17. It has not, however, shown the revenue for each month in the PGVA schedule (Exhibit Q2-3, Tab 1, Schedule 2, p. 1). In its submissions in EGDs previous ORAM IGUA supported OEB Staffs suggestion for separate reporting, and would appreciate it if EGD could acknowledge that, going forward , it will provide reporting of extraction revenues on a monthly basis as previously undertaken.

RESPONSE

EGD acknowledges that going forward it will provide reporting of extraction revenues on a monthly basis. Please see attached table for a monthly breakdown of the current QRAM amount previously filed.

Witness: D. Small

Extraction Revenue

2013	
January	248,055.78
February	208,846.50
March	246,808.37
April	239,116.37
May	229,135.34
June	215,674.89
July	242,299.50
August	251,351.83
September	222,842.66
October	230,833.07
November	647,758.05
December	645,943.22
	3,628,665.58

2014	
January	646,338.32
February - est	630,000.00

note (1) - as per the EB-2013-0046 Settlement Agreement Extraction Revenues were to be included as a reduction to gas acquisition costs for the January 2013 to August 2013 period Extraction Revenues equalled 1,881,288.58

note (2) - the evidence references Extraction Revenue of $4.2 million this is based upon the monthly amounts from above for the months of April 2013 to February 2014