CME INTERROGATORY #1

INTERROGATORY

Issues A – QRAM Review

Ref: November 27, 2008 Technical Conference Transcript, pages 65 to 83

Utility Policies

Would each utility please provide a statement of policy which summarizes the periodic rate adjustment mechanism each of them proposes to apply to reflect changes in the commodity price of “12 month” gas. Please include in these policy statements a brief description of the following items:

(a) The trading point at which changes in the commodity price of “12 month” gas will be measured.

(b) The information and methodology that will be used to measure changes in the commodity price of “12 month” gas at that point.

(c) A list of each of the components of utility rates that will be affected by a change in the commodity price of “12 month” gas at that trading point, such as, for example, the following:

- gas commodity charge
- the carrying cost of gas in inventory, including an identification of the particular component of regulated rates in which that gas-related cost is recovered, i.e. the regulated transportation charge, the load balancing/storage charge and/or commodity charge
- unaccounted for gas, including the identification of the component of rates in which that item of gas-related costs is recovered
- compressor fuel, including an identification of the component rate in which that item of gas-related cost is recovered
- any other gas-related costs and the components of the rates affected thereby

Witnesses: J. Collier
M. Giridhar
A. Kacicnik
D. Small

RESPONSE

a), b), c) See response to CME Interrogatory # 5 at Exhibit IR5, Schedule 5.

Witnesses: J. Collier
M. Giridhar
A. Kacicnik
D. Small

CME INTERROGATORY #2

INTERROGATORY

Issues A – QRAM Review

Ref: November 27, 2008 Technical Conference Transcript, pages 65 to 83

Method for Calculating the Reference Price

Would each utility please describe the precise meaning it ascribes to the phrase "Reference Price".

RESPONSE

EGD uses the term "Reference Price" and "Utility Price" interchangeably. Both represent the unit rate associated with the forecast gas supply acquisition cost which includes gas supply commodity, delivered supplies and transportation costs.

Witnesses: M. Giridhar
D. Small

CME INTERROGATORY #3

INTERROGATORY

Issues A – QRAM Review

Ref: November 27, 2008 Technical Conference Transcript, pages 65 to 83

Utility Products or Services Sold in Competitive Markets

Would each utility please describe the regulated products or services it provides in competition with unregulated gas commodity sellers.

RESPONSE

Gas vendors (i.e., unregulated sellers) provide gas supply and upstream transportation service to customers under a variety of arrangements (price, term).

Enbridge provides default gas supply and upstream transportation service at Board approved rates. The Company determines rates for these services as per the Board approved QRAM methodology. The Company does not promote these services or react competitively to offerings / developments in the marketplace.

For these reasons, the Company does not consider the default regulated gas supply service to be in competition with unregulated market offerings.

Witnesses: J. Collier
M. Giridhar
A. Kacicnik
D. Small

CME INTERROGATORY #4

INTERROGATORY

Issues A – QRAM Review

Ref: November 27, 2008 Technical Conference Transcript, pages 65 to 83

Utility Products or Services Sold in Competitive Markets

Would each utility please produce any advertising materials they have in their possession which reveal how unregulated gas sellers compete with the regulated products and/or services utilities offer in competition with unregulated gas sellers.

RESPONSE

Enbridge does not receive marketing/advertising materials from gas vendors (i.e., unregulated gas sellers).

Witnesses: J. Collier
A. Kacicnik
M. Giridhar
D. Small

CME INTERROGATORY #5

INTERROGATORY

Issues A – QRAM Review

Ref: November 27, 2008 Technical Conference Transcript, pages 65 to 83

Filing Requirements

Would each utility please provide, in point form, a complete step by step summary of the process each of them proposes to follow to
periodically update regulated rates to reflect changes in the commodity price of "12 month" gas. Please attach to the step by step summary description of the process each utility proposes to follow a sample of the gas cost schedules and other schedules each utility proposes to file with the Board.

RESPONSE

Description of QRAM Methodology for the Determination of Gas Costs

Every year the Company prepares a volumetric forecast for the upcoming test year based upon degree days, average customer use, and customer additions.

The gas supply portfolio is developed based on the volumetric forecast. The gas supply portfolio consists of contracted pipeline capacity (i.e., TCPL, Alliance/Vector) and the physical supplies to fill those contracts, delivered supplies and peaking services. The supply portfolio identifies the forecasted volumes to be purchased each month at the various supply basins and/or hubs such as AECO, Empress, Chicago and Dawn.

EGD maintains a database of future market prices for the price points identified above. /r
These prices are derived from a number of industry sources such as Gas Daily and NGX.

The process to determine the QRAM reference price is identical for each QRAM. If EGD were to use the October 1, 2008 QRAM as an example (EB-2008-0263) the process would be as follows:

Witnesses:	J. Collier	A. Kacicnik
	K. Culbert	M. Suarez
	M. Giridhar	D. Small

1) Calculate the 21-day average price for each month for each price point for the period of the QRAM. These forecasted monthly prices are provided at Exhibit Q4-3, Tab 1, Schedule 3, page 1.

2) Apply the forecasted monthly prices to the monthly forecasted volumes and determine the forecasted annual acquisition cost for each source of supply. These forecasted annual supply costs are provided at Exhibit Q4-3, Tab 1, Schedule 1, page 1, Item #'s 1 to 5.

3) Include the impact of approved tolls on the contracted capacity levels included in the supply portfolio. This will capture any changes in tolls such as NEB approved TCPL toll changes. These forecasted transportation costs are provided at Exhibit Q4-3, Tab 1, Schedule 1, page 1, Item # 7.

4) Calculate the "Reference Price". Divide the total annual acquisition cost by the forecasted volume. Exhibit Q4-3, Tab 1, Schedule 1, page 1, Item # 10.

5) Calculate the change in the "Reference Price". Exhibit Q4-3, Tab 1, Schedule 1, page 1, Item # 12.

The process for the subsequent QRAM will be to update the pricing forecast for a new 21-day period and then apply that forecast to the same monthly volumetric forecast.

A copy of the October QRAM schedules has been provided as an attachment.

<u>Description of the Determination of the Annualized Revenue Requirement Within the QRAM Methodology.</u>

The Company is not proposing any changes to its current QRAM methodology relating to its determination of the annualized revenue requirement. The methodology described below is consistent with the evidence which is currently filed with each QRAM application.

1) First the forecast change in the gas commodity reference price is applied against the Board approved gas cost volumes to arrive at a forecast annual change in the purchase cost of gas.

2) Next, any change in approved TCPL tolls is incorporated to reflect an associated change in the anticipated T-service credit forecast.

Witnesses:		
	J. Collier	A. Kacicnik
	K. Culbert	M. Suarez
	M. Giridhar	D. Small

3) Next, the forecast change in the reference price is applied against the Board approved gas in storage volumes to determine the forecast change in gas in storage value and within the approved methodology of determining the impact within working cash related rate base elements. The total of these rate base impacts have the Board approved total return on rate base, grossed up for tax purposes, applied against them to determine the associated forecast change in carrying costs to be incorporated within annualized rates.

4) The impact of the forecast change in the gas commodity reference price also results in a change in the level of forecast capital tax associated with storage values which is also incorporated within annualized rates.

Please see the response to CME Interrogatory #8 at Exhibit IR 5, Schedule 8 for the exhibit examples which the Company currently files within its QRAM methodology and proposes to continue using.

This process is outlined in the Company's evidence in relation to Issue 5, pages 20 to 22. This description and the exhibits filed in response to CME Interrogatory #8 are the same as the process which is followed within each of the Company's QRAM applications.

Description of the QRAM Methodology for the Determination of Rates

The Company is not proposing any changes to its current QRAM methodology relating to its cost allocation and rate design process. The methodology described below is consistent with the evidence which is currently filed with each QRAM application.

1) Update the cost allocation model and rate design models relating to the changes in the determination of gas costs and other revenue requirement impacts as outlined above.

2) The gas supply charge is updated to reflect the forecast Empress reference price inclusive of fuel and the associated commodity related working cash requirement. The system gas fee and commodity related bad debt expense which also make up the gas supply charge do not change within a QRAM application.

3) The load balancing charge is updated to reflect change to the return on gas in inventory, discretionary and short term peaking supplies, and capital and large corporation taxes.

Witnesses:	J. Collier	A. Kacicnik
	K. Culbert	M. Suarez
	M. Giridhar	D. Small

4) The transportation charge is updated to reflect changes in upstream transportation costs.

5) The delivery charge is updated to reflect changes in lost and unaccounted for gas.

A further description of the cost allocation and rate design processes can be found in the Cost Allocation portion of the Company's evidence filed at Exhibit E1, Issue C, pages 40 to 47 or in any of the Company's QRAM applications filed at Exhibit Qx-2. Tabs 3 and 4.

For sample cost allocation and rate design schedules, given that they consist of a number of pages, from October 1, 2008 QRAM application please see EB-2008-0263, Exhibit Q4-3, Tabs 3 and 4.

MONTHLY PRICING INFORMATION

	Col. 1 21 Day Average Empress CGPR	Col. 2 21 Day Average NYMEX	Col. 3 21 Day Average Chicago	Col. 4 21 Day Average US Exchange	Col. 5 $CAD/10^{3}m^3 Equivalent (Note 1)
	$CAD/GJ	$US/MMBtu	$US/MMBtu	$CAD/$US	
Oct-08	7.8186	9.1553	8.9097	1.0361	
Nov-08	8.2562	9.5191	9.4968	1.0365	
Dec-08	8.7110	9.9143	9.8920	1.0367	
Jan-09	8.8893	10.1365	10.1142	1.0368	
Feb-09	8.9347	10.1405	10.1182	1.0368	
Mar-09	8.8355	9.9696	9.9473	1.0367	
Apr-09	8.2142	9.2760	9.2617	1.0367	
May-09	8.1798	9.2150	9.2007	1.0366	
Jun-09	8.2624	9.3004	9.2861	1.0365	
Jul-09	8.3694	9.3976	9.3833	1.0364	
Aug-09	8.4340	9.4640	9.4497	1.0362	
Sep-09	8.4661	9.4973	9.4830	1.0361	
	8.4476	9.5821	9.5452	1.0365	318.3902
TCPL Fuel Ratio		4.56%			332.9138

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

21 Day Period **18-Jul-08** **to** **15-Aug-08**

Natural Gas Conversions

mcf times 0.028328 = 10^3m^3

1 Dth = 1 mcf

MMBtu times 1.055056 = GJ's

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

$/MMBtu divided by 1.055056 = $/GJ

$/GJ times MJ/m^3 = $/10^{3}m^3

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

Summary of Gas Cost to Operations
Year ended September 30, 2009

Item #		Col. 1 10^3m^3	Col. 2 $(000)	Col. 3 $/$10^3m^3$ (Col.2 / Col.1)	Col. 4 $/GJ (Col.3 / 37.69)	Col. 5 % Change from Previous QRAM
	Western Canadian Supplies					
1.1	Alberta Production	0.0	0.0	0.000	0.000	0.0%
1.2	Western - @ Empress - TCPL	426,592.4	136,013.4	318.837	8.459	-13.4%
1.3	Western - @ Nova - TCPL	358,056.6	112,576.3	314.409	8.342	-13.6%
1.4	Western Buy/Sell - with Fuel	4,515.5	1,484.9	328.838	8.725	-13.4%
1.5	Western - @ Alliance	966,103.9	341,841.1	353.835	9.388	-13.7%
1.6	Less TCPL Fuel Requirement	(34,428.0)	0.0			
1.	Total Western Canadian Supplies	1,720,840.5	591,915.7	343.969	9.126	-13.6%
	Short Term Supplies					
2.	Peaking/Seasonal	56,300.0	30,002.3	532.901	14.139	-9.6%
3.	Ontario Production	1,464.1	531.4	362.926	9.629	-11.3%
	Chicago Supplies					
4.1	Vector 1st Tranche	8,303.0	2,866.6	345.251	9.160	-15.4%
4.2	Vector 2nd Tranche	807,280.4	286,209.5	354.535	9.407	-12.8%
4.3	Vector 3rd Tranche	1,450,877.4	514,387.5	354.535	9.407	-12.8%
4.	Total Chicago Supplies	2,266,460.8	803,463.6	354.501	9.406	-12.8%
	Delivered Supplies					
5.1	Link Supplies	76,840.8	28,473.3	370.550	9.832	-12.7%
5.2	Ontario Delivered	902,349.7	349,377.0	387.186	10.273	-12.7%
5.	Total Other Delivered Supplies	979,190.4	377,850.4	385.880	10.238	-12.7%
6.	Total Supply Costs	5,024,255.8	1,803,763.3	359.011	9.525	-13.0%
	Transportation Costs					
7.1	TCPL - FT - Demand		36,049.2			
7.2	- FT - Commodity	754,736.5	3,510.0	4.651	0.123	-0.8%
7.3	Capacity Discounts		0.0			
7.4	- STS - CDA		4,417.4			
7.5	- STS - EDA		2,775.5			
7.6	- Dawn to CDA Exchange		9,414.5			
7.7	- Dawn to EDA Exchange		14,684.2			
7.8	Union C1 Transportation		0.0			
7.9	Nova Transmission		1,966.4			
7.10	ANR/Michcon Transportation		979.5			
7.11	Link Pipeline		119.8			
7.12	Alliance Pipeline		40,268.1			
7.13	Vector Pipeline - 1st Tranche		8,163.5			
7.14	Vector Pipeline - 2nd Tranche		6,718.7			
7.15	Vector Pipeline - 3rd Tranche		12,075.2			
7.	Total Transportation Costs		141,142.0			
8.	Total Before PGVA Adjustment	5,024,255.8	1,944,905.3	387.103	10.271	-11.8%
9.	PGVA Adjustment		0.0			
10.	Total Purchases & Receipt	5,024,255.8	1,944,905.3	387.103	10.271	
11.	PGVA Reference Price as per EB-2008-0069			438.790	11.642	
12.	Upstream Increase/Decrease on 2008 PGVA Reference Price			(51.687)	(1.371)	
13.	Updated T-Service Credits	6,835,325.0	361,569.4	52.897	1.403	
14.	T-Service Credits - as per EB-2008-0069 Q3-3 T1 S1 p1	6,835,325.0	338,324.0	49.496	1.313	
15.	Upstream Increase on T-Service Credits			3.401	0.090	

CME INTERROGATORY #6

INTERROGATORY

Issues A – QRAM Review

Ref: November 27, 2008 Technical Conference Transcript, pages 65 to 83

Filing Requirements

Using the schedules attached to the response to the previous question, please illustrate each of the changes that will occur in the line items of each schedule with an assumed $1/GJ change in the commodity price of "12 month" gas at Empress.

RESPONSE

It would be virtually impossible for there to be a $1/GJ commodity price change that would affect only Empress. It is also unlikely that a $1/GJ at Empress would translate into an equivalent price change at other receipt points i.e. Chicago and Dawn. However, for the purposes of the attached schedules the Company has assumed a $1/GJ change for all gas supplies, excluding transportation tolls.

As identified at Item # 12 of the attached schedule a $1/GJ commodity price increase results in a $37.94/10^3 m^3 increase versus the October 1, 2008 QRAM Reference Price.

Witnesses: J. Collier A. Kacicnik
K. Culbert D. Small
M. Giridhar M. Suarez

Summary of Gas Cost to Operations
Year ended September 30, 2009

Item #		Col. 1 10^3m^3	Col. 2 $(000)	Col. 3 $\$/10^3m^3$ (Col.2 / Col.1)	Col. 4 $/GJ (Col.3 / 37.69)
	Western Canadian Supplies				
1.1	Alberta Production	0.0	0.0	0.000	0.000
1.2	Western - @ Empress - TCPL	426,592.4	152,091.7	356.527	9.459
1.3	Western - @ Nova - TCPL	358,056.6	126,071.5	352.099	9.342
1.4	Western Buy/Sell - with Fuel	4,515.5	1,655.1	366.528	9.725
1.5	Western - @ Alliance	966,103.9	378,253.6	391.525	10.388
1.6	Less TCPL Fuel Requirement	(34,428.0)	0.0		
1.	Total Western Canadian Supplies	1,720,840.5	658,071.8	382.413	10.146
	Short Term Supplies				
2.	Peaking/Seasonal	56,300.0	32,124.3	570.591	15.139
3.	Ontario Production	1,464.1	586.5	400.616	10.629
	Chicago Supplies				
4.1	Vector 1st Tranche	8,303.0	3,179.5	382.941	10.160
4.2	Vector 2nd Tranche	807,280.4	316,635.9	392.225	10.407
4.3	Vector 3rd Tranche	1,450,877.4	569,071.0	392.225	10.407
4.	Total Chicago Supplies	2,266,460.8	888,886.5	392.191	10.406
	Delivered Supplies				
5.1	Link Supplies	76,840.8	31,369.5	408.240	10.832
5.2	Ontario Delivered	902,349.7	383,386.6	424.876	11.273
5.	Total Other Delivered Supplies	979,190.4	414,756.0	423.570	11.238
6.	Total Supply Costs	5,024,255.8	1,994,425.1	396.959	10.532
	Transportation Costs				
7.1	TCPL - FT - Demand		36,049.2		
7.2	- FT - Commodity	754,736.5	3,510.0	4.651	0.123
7.3	Capacity Discounts		0.0		
7.4	- STS - CDA		4,417.4		
7.5	- STS - EDA		2,775.5		
7.6	- Dawn to CDA Exchange		9,414.5		
7.7	- Dawn to EDA Exchange		14,684.2		
7.8	Union C1 Transportation		0.0		
7.9	Nova Transmission		1,966.4		
7.10	ANR/Michcon Transportation		979.5		
7.11	Link Pipeline		119.8		
7.12	Alliance Pipeline		40,268.1		
7.13	Vector Pipeline - 1st Tranche		8,163.5		
7.14	Vector Pipeline - 2nd Tranche		6,718.7		
7.15	Vector Pipeline - 3rd Tranche		12,075.2		
7.	Total Transportation Costs		141,142.0		
8.	Total Before PGVA Adjustment	5,024,255.8	2,135,567.1	425.051	11.278
9.	PGVA Adjustment		0.0		
10.	Total Purchases & Receipt	5,024,255.8	2,135,567.1	425.051	11.278
11.	PGVA Reference Price as per EB-2008-0263			387.103	10.271
12.	Upstream Increase/Decrease on 2008 PGVA Reference Price			37.948	1.007

CME INTERROGATORY #7

INTERROGATORY

Issues A – QRAM Review

Ref: November 27, 2008 Technical Conference Transcript, pages 65 to 83

Filing Requirements

Using the response to the previous question, please describe and attach schedules to show how changes in the utility cost of gas arising from an assumed $1/GJ change in the commodity cost of “12 month” gas at Empress are affected by the cost allocation process and, in particular, describe and attach schedules to show how the utility cost of gas is allocated between commodity costs, transportation costs, and storage and/or load balancing costs.

RESPONSE

The attached table shows the allocation of an assumed $1/GJ increase in gas supply costs, as compared to October 1, 2008 QRAM, presented in the response to CME Interrogatory #6 at Exhibit IR5, Schedule 6.

Col. 1 shows the allocation of the gas cost change between commodity, transportation, load balancing, storage and distribution components.

Col. 15 denotes recovery of unit rate changes from the assumed change in gas costs as compared to October 1, 2008 QRAM through the gas supply, transportation, load balancing or delivery charges.

Please see Exhibit E1, Issue C: Cost Allocation for a further description for the Company’s cost allocation methodology and the response to CME Interrogatory #5 at Exhibit IR5, Schedule 5.

Witnesses: J. Collier
K. Culbert
M. Giridhar
A. Kacicnik
D. Small
M. Suarez

CALCULATION OF UNIT RATE CHANGE FROM $1 /GJ PRICE INCREASE ON OCTOBER 1, 2008 RATES
BY CUSTOMER CLASS
($millions)

		COL. 1	COL. 2	COL. 3	COL. 4	COL. 5	COL. 6	COL. 7	COL. 8	COL. 9	COL. 10	COL. 11	COL. 12	COL. 13	COL. 13	COL. 14	COL. 15
		TOTAL	RATE 1	RATE 6	RATE 9	RATE 100	RATE 110	RATE 115	RATE 125	RATE 135	RATE 145	RATE 170	RATE 200	RATE 300	RATE 300 Int	FACTORS Q3-3.3.4	Change in Rates
	ALLOCATION OF GAS COSTS																
1.1	ANNUAL COMMODITY	189.51	110.46	64.26	0.08	3.49	0.95	1.83	0.00	0.13	1.22	2.46	4.62	0.00	0.00	1.1	
1.2	PIPELINE PEAK	(0.12)	(0.06)	(0.05)	0.00	(0.01)	(0.00)	(0.00)	0.00	0.00	0.00	0.00	(0.00)	0.00	0.00	3.1	
1.3	PIPELINE SEASONAL	(0.95)	(0.44)	(0.38)	0.00	(0.05)	(0.01)	(0.01)	0.00	0.00	(0.01)	(0.02)	(0.01)	0.00	0.00	3.2	
1.4	PIPELINE ANNUAL	(7.29)	(2.84)	(2.36)	(0.00)	(0.41)	(0.38)	(0.57)	0.00	(0.03)	(0.14)	(0.46)	(0.09)	0.00	0.00	1.2	
1.5	DISTRIBUTION COMMODITY	1.40	0.55	0.45	0.00	0.08	0.07	0.11	0.00	0.01	0.03	0.09	0.02	0.00	0.00	1.2	
1.6	SPACE	0.86	0.40	0.35	0.00	0.05	0.01	0.01	0.00	0.00	0.01	0.02	0.01	0.00	0.00	3.2	
1.7	DELIVERABILITY	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	3.1	
		-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----		
1.	TOTAL	183.41	108.06	62.26	0.08	3.14	0.64	1.38	0.00	0.10	1.11	2.09	4.55	0.00	0.00		
	ALLOCATION OF RETURN AND TAXES																
2.1	ANNUAL COMMODITY	0.24	0.14	0.08	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.00	0.00	1.1	
2.2	SEASONAL SPACE	4.47	2.09	1.80	0.00	0.24	0.07	0.03	0.00	0.00	0.06	0.12	0.06	0.00	0.00	3.2	
		-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----		
2.	TOTAL	4.71	2.23	1.89	0.00	0.24	0.07	0.04	0.00	0.00	0.07	0.12	0.06	0.00	0.00		
	TOTAL																
3.1	ANNUAL COMMODITY	189.75	110.60	64.34	0.08	3.49	0.95	1.84	0.00	0.13	1.22	2.47	4.63	0.00	0.00	1.1	
3.2	PIPELINE PEAK	(0.12)	(0.06)	(0.05)	0.00	(0.01)	(0.00)	(0.00)	0.00	0.00	0.00	0.00	(0.00)	0.00	0.00	3.1	
3.3	PIPELINE SEASONAL	(0.95)	(0.44)	(0.38)	0.00	(0.05)	(0.01)	(0.01)	0.00	0.00	(0.01)	(0.02)	(0.01)	0.00	0.00	3.2	
3.4	PIPELINE ANNUAL	(7.29)	(2.84)	(2.36)	(0.00)	(0.41)	(0.38)	(0.57)	0.00	(0.03)	(0.14)	(0.46)	(0.09)	0.00	0.00	1.2	
3.5	DISTRIBUTION COMMODITY	1.40	0.55	0.45	0.00	0.08	0.07	0.11	0.00	0.01	0.03	0.09	0.02	0.00	0.00	1.2	
3.6	SEASONAL SPACE	4.47	2.09	1.80	0.00	0.24	0.07	0.03	0.00	0.00	0.06	0.12	0.06	0.00	0.00	3.2	
3.7	SPACE	0.86	0.40	0.35	0.00	0.05	0.01	0.01	0.00	0.00	0.01	0.02	0.01	0.00	0.00	3.2	
3.8	DELIVERABILITY	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	3.1	
		-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----		
3.	TOTAL	188.12	110.29	64.15	0.08	3.38	0.71	1.41	0.00	0.10	1.17	2.21	4.61	0.00	0.00		
	UNIT RATE CHANGE ($ per 10^3m^3)																
4.1	ANNUAL COMMODITY	39.74	39.74	39.74	39.74	39.74	39.74	39.74	0.00	39.74	39.74	39.74	39.74	0.00	0.00		Gas Supply Charge
4.2	PIPELINE PEAK	(0.01)	(0.01)	(0.01)	0.00	(0.01)	(0.00)	(0.00)	0.00	0.00	0.00	0.00	(0.01)	0.00	0.00		Load Balancing Charge
4.3	PIPELINE SEASONAL	(0.08)	(0.10)	(0.10)	0.00	(0.08)	(0.02)	(0.01)	0.00	0.00	(0.06)	(0.03)	(0.08)	0.00	0.00		Load Balancing Charge
4.4	PIPELINE ANNUAL	(0.63)	(0.63)	(0.63)	(0.63)	(0.63)	(0.63)	(0.63)	0.00	(0.63)	(0.63)	(0.63)	(0.63)	0.00	0.00		Transportation Charge
4.5	DISTRIBUTION COMMODITY	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.00	0.12	0.12	0.12	0.12	0.00	0.00		Delivery Charge
4.6	SEASONAL SPACE	0.38	0.46	0.48	0.00	0.36	0.11	0.04	0.00	0.00	0.29	0.16	0.38	0.00	0.00		Load Balancing Charge
4.7	SPACE	0.07	0.09	0.09	0.00	0.07	0.02	0.01	0.00	0.00	0.06	0.03	0.07	0.00	0.00		Delivery Charge
4.8	DELIVERABILITY	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00		Delivery Charge
		-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----		
5.0	TOTAL SALES	39.60	39.67	39.69	39.23	39.58	39.34	39.27	0.00	39.23	39.52	39.39	39.59	0.00	0.00		
6.0	TOTAL T-SERVICE	(0.14)	(0.07)	(0.05)	(0.51)	(0.16)	(0.40)	(0.47)	0.00	(0.51)	(0.22)	(0.35)	(0.15)	0.00	0.00		

ITEM 3.1 = ITEM 1.1 + ITEM 2.1
ITEM 3.2 = ITEM 1.2
ITEM 3.3 = ITEM 1.3
ITEM 3.4 = ITEM 1.4
ITEM 3.5 = ITEM 1.5
ITEM 3.6 = ITEM 2.2
ITEM 3.7 = ITEM 1.6
ITEM 3.8 = ITEM 1.7
ITEM 4.1 = ITEM 3.1/ANNUAL SALES
ITEM 4.2 - ITEM 3.2/BUNDLED ANNUAL DELIVERIES
ITEM 4.3 = ITEM 3.3/BUNDLED ANNUAL DELIVERIES
ITEM 4.4 = ITEM 3.4/BUNDLED ANNUAL DELIVERIES
ITEM 4.5 = ITEM 3.5/TOTAL ANNUAL DELIVERIES
ITEM 4.6 = ITEM 3.6/BUNDLED ANNUAL DELIVERIES
ITEM 4.7 = ITEM 3.7/BUNDLED ANNUAL DELIVERIES
ITEM 4.8 = ITEM 3.8/BUNDLED ANNUAL DELIVERIES

CME INTERROGATORY #8

INTERROGATORY

Issues A – QRAM Review

Ref: November 27, 2008 Technical Conference Transcript, pages 65 to 83

Other Revenue Requirement Items

Would each utility please provide a step by step description of the manner in which a change in the commodity cost of “12 month” gas at the reference point affects the other gas-related revenue requirement items in rates such as the carrying cost of gas and inventory, unaccounted for gas, compressor fuel, etc. Please attach schedules to the response to illustrate how a $1/GJ change in the commodity cost of gas affects each of these components of rates.

RESPONSE

The Company provided a step by step description of its process within the response to CME Interrogatory #5 at Exhibit IR5, Schedule 5. The attached example exhibits show the impact of a $1/GJ assumed increase in the gas reference price within each of the described and affected revenue requirement related items.

Witnesses: J. Collier
K. Culbert
M. Giridhar
A. Kacicnik
D. Small
M. Suarez

Annualized Impact of a $1 per GJ change to the October 1, 2008 Gas Cost Reference Price
on the Company's F2008 Test Year Revenue Requirement

Line No.	Impact of cost change on utility operations	Item Numbers	NOTE	Col.1 Exhibit Reference	Col.2 Volume	Col. 3 Change in Unit Rates	NOTE	Col. 4 Quarterly Rate Adjustment Impact
					(10^3 M^3)	($/$10^3$ M^3)		($000)
1.	Forecast volumes from EB-2007-0615	(4.1, 4.2, 4.3, & 4.6)	**B**	C.T1.S2.p2	4 774 663.8	37.948	**A**	181,188.9
2.	Forecast Company use volume	(4.7)	**B**	C.T1.S2.p2	6 284.9	37.948	**A**	238.5
3.	Forecast unbilled and unaccounted for volume	(4.8 & 4.9)	**B**	C.T1.S2.p2	29 663.9	37.948	**A**	1,125.7
4.	Forecast lost and unaccounted for volume	(4.11)	**B**	C.T1.S2.p2	23 763.5	37.948	**A**	901.8
5.	EB-2007-0615 approved utility gas costs volume - excluding T-service				4 834 376.1			
6.	Gross upstream pass-on of change in purchase cost of gas							183,454.9
						($000)		
7.	Impact of upstream pass-on of T-service credits			Q4-3.T1.S1, item 13		361,569.4		
8.	T-service credits excluding upstream pass-on			Q4-3.T1.S1, item 13		361,569.4		-
9.	Total impact of upstream pass-on change in purchase cost of gas							183,454.9
10.	Impact on carrying cost requirement as a result of upstream pass-on impact on rate base			Q4-3.T2.S2				4,531.6
11.	Impact on capital taxes			Q4-3.T2.S3				182.0
12.	Increase (decrease) in revenue requirement							188,168.5

Note : A

Line		Exhibit Reference	Docket No.	
13.	PGVA reference price, Oct.08 changed by $1/GJ			425.051
14.	PGVA reference price approved and effective October 1, 2008	Q4-3.T1.S1, item 10	EB-2008-0263	387.103
15.	Change in price			37.948

Note : B

16. Volumes are from Exhibit C, Tab 1, Schedule 2, page 2,
Filed: 2007-09-04, within EB-2007-0615 (Decision Date, 2008-02-11).

Annualized Impact of a $1 per GJ change to the October 1, 2008 Gas Cost Reference Price on Rate Base and its Associated
Gross Carrying Cost

Line No.	Impact of cost change on utility operations	Col.1 Exhibit Reference	Col.2	Col.3
				($000)
1.	Effect on gas in storage of the pass-on of the gas purchase unit rate change	Q4-3.T2.S6	1 207 174.0	
2.	Gas purchase unit rate change applied to the volume of gas in storage	Q4-3.T1.S1	$37.948	45,809.8
3.	Effect on working cash allowance of the upstream pass-on			
3.1	a) Net change in purchase cost of gas	Q4-3.T2.S1	$183,454.9	
3.2	b) Net lag-days calculated	Q4-2.T3.S1.p1	4.2	
3.3	c) Dollar days		770,510.6	
3.4	d) Number of operating days		366	2,105.2
4.	Effect on Goods and Services Tax of the upstream pass-on	Q4-2.T3.S1.p1		500.0
5.	Change in Rate Base			48,415.0
6.	Gross return component	Q4-3.T2.S4		9.36%
7.	Effect on carrying cost requirement			4,531.6

Annualized Impact of a $1 per GJ change to the October 1, 2008 Gas Cost Reference Price
on Capital Taxes

Line No.	Impact of cost change on utility operations		Col.1 Exhibit Reference	Col.2	Col.3 ($000)
1.	Year end forecast of gas in storage volume	(10^3 M^3)	Q4-3.T2.S6	1 641 530.5	
2.	Gas purchase unit rate change applied to the year end forecast of gas in storage volume	(\$/10^3 M^3)	Q4-3.T1.S1	$37.948	
3.	Year end gas in storage rate base change	($000)		62,292.8	
4.	Effect on capital taxes of the upstream pass-on				
4.1	a) Year end gas in storage change		(line 3, col.2 above)	62,292.8	
4.2	b) Working cash allowance & GST level changes		Q4-3.T2.S2	1,572.1	
4.3	c) Taxable Capital base change			63,864.9	
4.4	d) Provincial capital tax rate			0.285%	
4.5	e) Provincial capital tax change, does not require gross up tax treatment				182.0

Calculation of the Gross Rate
of Return on Rate Base

Line No.		Col.1 Capital Structure Component (Note 1)	Col.2 Indicated Cost Rate (Note 1)	Col.3 Net Return Component (Note 1)	Col.4 Reciprocal of the Tax rate (Note 2)	Col.5 Gross Return Component
		%	%	%		%
1.	Long-term debt	59.65	7.31	4.36		4.36
2.	Short-term debt	1.68	4.12	0.07		0.07
3.	Tax shielded	61.33		4.43		4.43
4.	Preference shares	2.67	5.00	0.13	0.6388	0.20
5.	Common equity	36.00	8.39	3.02	0.6388	4.73
6.	Non tax shielded	38.67		3.15		4.93
7.		100.00		7.58		9.36

Note 1: The source for Columns 1 to 3 is the cost of capital found in the EB-2006-0034, Final Rate Order, Appendix A, Schedule 4, Columns 2 to 4, Dated: 2007-09-24 as explained at Exhibit Q4-2, Tab 2, Schedule 1, paragraph 7.

Note 2: A Board Approved 2007 corporate income tax rate of 36.12% is to be used within the gross return calculation for 2008-2012. The impacts of forecast income tax rate changes for the years 2008-2012 and any variances from forecast tax rate changes are handled within the Board Approved 2008 Incentive Regulation - ADR Settlement Agreement, Appendix D.

CME INTERROGATORY #9

INTERROGATORY

Issue B – Load Balancing Review

Ref: November 27, 2008 Technical Conference Transcript, pages 123 to 138

Utility Policies

Would each utility please provide a statement of policy which summarizes the load balancing services they propose to provide to direct purchasers using bundled delivery services. Please include in these policy statements a concise description of the manner each utility proposes to establish and re-establish the Daily Contract Quantity (“DCQ”) or the Mean Daily Volume (“MDV”) of direct purchasers acquiring bundled delivery services from each utility.

RESPONSE

Enbridge meets the load balancing needs of both its system gas and direct purchase bundled customers using a variety of tools in a cost effective manner, as outlined in Enbridge’s evidence at Exhibit E1, Paragraphs 108 to 111, pages 33 to 34.

Also stated in the above noted evidence at Paragraph 99, page 31, is the current methodology used by Enbridge to establish the MDV/DCQ. For a description of the manner in with Enbridge proposes to re-establish the MDV/DCQ, please see the response to IGUA Interrogatory #4, a) at Exhibit IR11, Schedule 4.

Witnesses: J. Collier
M. Giridhar
A. Kacicnik
B. Manwaring
D. Small

CME INTERROGATORY #10

INTERROGATORY

Issue C – Cost Allocation Review

Ref: November 28, 2008 Technical Conference Transcript, pages 18 to 27

Methodology for Identifying and Allocating Costs between System Gas Customers and Direct Purchasers

Would each utility please provide a concise description of the cost allocation methodology it proposes to apply to determine the charges to be recovered from system gas customers as a System Gas Administration Fee and the charges to be recovered from direct purchasers as a Direct Purchase Administration Fee.

RESPONSE

As outlined in its evidence at Exhibit E1, pages 40 to 54, the Company uses the incremental costing approach to determine the appropriate level of costs related to system gas and direct purchase functions. This methodology examines which operating costs would be avoided or eliminated if the Company were no longer required to support system gas or direct purchase options. The costs are either directly identifiable as being system gas or direct purchase related or in instances where a function supports both service options, full time equivalents (FTEs) are used to allocate between system gas and direct purchase.

Please see the response to Gas Marketers Group Interrogatory #27 at Exhibit IR8, IR14, IR18, IR19, Schedule 27 which identifies the functions and related costs associated with the existing and proposed system gas and direct purchase fees.

Witnesses: J. Collier
A. Kacicnik
M. Suarez

CME INTERROGATORY #11

INTERROGATORY

Issue C – Cost Allocation Review

Ref: November 28, 2008 Technical Conference Transcript, pages 18 to 27

Methodology for Identifying and Allocating Costs between System Gas Customers and Direct Purchasers

Please list each of the activities or resources that is considered when applying the cost allocation methodology described in response to the previous question and provide a step by step description of the manner in which the costs of each activity or resource attributable to system gas customers and to direct purchasers are identified and allocated.

RESPONSE

Please see the response to CME Interrogatory #10 at Exhibit IR5, Schedule 10.

Witnesses: J. Collier
A. Kacicnik
M. Saurez

CME INTERROGATORY #12

INTERROGATORY

Issue C – Cost Allocation Review

Ref: November 28, 2008 Technical Conference Transcript, pages 18 to 27

Methodology for Identifying and Allocating Costs between System Gas Customers and Direct Purchasers

Would each utility please specify how frequently they propose to update their System Gas Administration and Direct Purchase Administration Fees.

RESPONSE

Please see the response to BOMA Interrogatory #4 filed at Exhibit IR4, Schedule 4 part f).

Witnesses: J. Collier
A. Kacicnik
M. Suarez