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December 31, 2008

VIA RESS, EMAIL and COURIER

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

Dear Ms. Walli:

**Re: Ontario Energy Board File No. EB-2008-0106
Commodity Pricing, Load Balancing and Cost Allocation
Methodologies for Natural Gas Distributors**

Pursuant to the Board's Procedural Order No. 2, attached please find Enbridge Gas Distribution's interrogatory responses in the above noted proceeding.

The following interrogatory responses are not included in this package and will be filed shortly, but not later than January 15, 2009:

CME Interrogatory #3;
CCC Interrogatory #3;
Gas Marketers Group Interrogatories #2, 6, 7, and 9;
VECC Interrogatories #1, 4, 5, 6, 7, and 9; and
Board Staff Interrogatories #2 and 5.

The attached evidence has been filed through the RESS and two paper copies are being forwarded to the Board via courier.

Yours truly,

SLSpratt for

Lorraine Chiasson
Regulatory Coordinator

cc: Mr. F. Cass, Aird & Berlis LLP (via email and courier)
EB-2008-0106 Interested Parties (via email)

BOMA INTERROGATORY #1

INTERROGATORY

Ref: Exhibit E1, page 2

If Enbridge were to purchase some of its system gas supply at a fixed price for any of the months included in the next 12 months, would this price and the associated volume be taken into account when setting the gas supply reference price? Please explain.

RESPONSE

EGD does not have a physical fixed price purchasing program in place. EGD discontinued its financial gas supply risk management program in 2007 pursuant to a Board decision on the issue.

EGD budgets its natural gas purchases based on indices and not fixed prices. The gas supply reference price is based upon budgeted volumes from various markets. Normally when the budget is prepared the specific supplier of the gas is not known. If EGD has a supply arrangement with a particular supplier for the budgeting period, then the associated volumes are incorporated at the index price for the appropriate future months.

Witnesses: M. Giridhar
D. Small

BOMA INTERROGATORY #2

INTERROGATORY

Ref: Exhibit E1, page 19 – 20

How will Enbridge determine the volume for the next 12 months that is used to calculate the rate riders associated with the debits/credits that are to be recovered prospectively? Are these volumes based on the most recent Enbridge forecast or fixed at the levels included in the last Board approved IRM filing? Are there separate rate riders and 12 month volume forecasts by rate class?

RESPONSE

Within a fiscal year there are four QRAM rate adjustments. The volume used to develop the Riders within the fiscal year will be based on the Board approved forecast for that fiscal year and therefore will be fixed. There will be a separate rider for each rate class based on the 12 month Board approved forecast for each rate class.

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

BOMA INTERROGATORY #3

INTERROGATORY

Ref: Exhibit E1, page 20

In calculating the effect of a change in the reference price on the revenue requirement, Union Gas includes the changes related to compressor fuel and unaccounted for gas in the Intra-period WACOG deferral account (Exhibit E2, page 12). Does Enbridge include the change in costs related to compressor fuel and/or unaccounted for gas in its calculation of the impact on the revenue requirement?

RESPONSE

Yes. The change in the reference price in relation to unaccounted for gas and compressor fuel is captured within the calculation of the impact on revenue requirement.

Witnesses: K. Culbert
D. Small

BOMA INTERROGATORY #4

INTERROGATORY

Ref: Exhibit E1, page 43

Union appears to include commodity related bad debt expense and the carrying cost on the gas purchase working capital as part of their system administration fee, while Enbridge appears to account for these costs outside of the system gas fee (paragraph 142).

a) Is there any implication in terms of the allocation methodology or any other difference in determining the amount of bad debt expense and/or the carrying cost on the gas purchase working capital outside of the system gas fee which is done on an incremental basis?

b) Why are any costs related to demand forecasting included in the system gas fee? What incremental function related to system gas are these costs related to?

c) How does Enbridge determine the portion of the bad debt expense to allocate to the system gas fee?

d) Does Enbridge allocate any of the investment carrying costs associated with customer deposits to the system gas fee? If not, why not?

e) What is the level of Enbridge's current system gas fee?

f) Does the system gas fee change during an incentive regulation period, or does it only change at a cost of service rebasing application?

g) Does Enbridge adjust the cost related to the commodity-related working cash that would result from a change in the cost of gas? If not, why not?

h) Please confirm that the system gas fee and DPAC fees do not include any allowance for costs or assets used by the employees directly involved in providing these services, such as computer hardware, software, office equipment and furniture.

i) Does the system gas fee include any regulatory costs associated with the preparation, filing and implementation of QRAM filings? If not, please explain why not.

Witnesses: J. Collier
A. Kacicnik
M. Suarez

RESPONSE

a) No. The impact is the same. The difference is that Enbridge breaks out the components of the gas supply charge.

b) Demand forecasting is an integral part of supply planning. By forecasting the demands of the system, Enbridge is able to optimize supply sources and transportation arrangements to ensure availability of gas supply for system gas customers.

c) Bad debt expense is allocated to system gas customers and forms part of their gas supply charge. It is allocated to the gas supply charge based on the proportion of total commodity revenues relative to total revenues. The remaining portion of the bad debt expenses is recovered in the delivery charge from all customers.

d) EGD is not certain what is meant by the term "investment carrying costs for security deposits". If it is intended to refer to the security deposit amounts which form part of rate base then this amount is not allocated to the system gas fee. As mentioned in part c) above, a portion of the bad debt expense which forms part of Company's operating and maintenance expenses is allocated to system gas customers and forms part of their gas supply charge.

e) Enbridge's system gas fee is 0.0185 cents per m^3 based on rates effective from October 1, 2008.

f) Enbridge would propose to update the level of the fee during its Incentive Regulation period as well as during the re-basing year. Please note that the update of such fee is revenue neutral for the Company.

g) Yes, Enbridge reflects any gas cost changes in the commodity-related working cash component during the QRAM process.

h) System Gas and Direct Purchase management costs are determined on an incremental basis which do not include general overhead costs associated with assets or activities that support the general functioning of the utility.

i) The system gas fee does not include any regulatory costs which are treated as general overhead costs. Whether the utility continues to provide system gas or not, the preparation, filing, and implementation of QRAM would continue to reflect other non-commodity gas costs (i.e., non gas supply charge related) and would not be considered incremental to the system gas management function.

Witnesses: J. Collier
A. Kacicnik
M. Suarez

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 #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. These prices are available from a number of industry sources such as Gas Daily which provides NYMEX future contract prices and from Canadian Gas Price Reporter ("CGPR") which provides forecast price point information for a number of locations. Information is also available from 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.

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

MONTHLY PRICING INFORMATION

	Col. 1 21 Day Average Empress CGPR	Col. 2 21 Day Average NYMEX	Col. 3 21 Day Average Chicago	Col. 4 21 Day Average US Exchange	Col. 5 $CAD/$10^3m^3$ Equivalent (Note 1)
	$CAD/GJ	$US/MMBtu	$US/MMBtu	$CAD/$US	
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/$10^3m^3$ = $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 = $/$10^3m^3$

$/MMBtu divided by 1.055056 = $/GJ

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

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

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, K. Culbert, M. Giridhar, A. Kacicnik, D. Small, 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

Filed: 2008-12-30
EB-2008-0106
Exhibit IR5
Schedule 7
Attachment

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 No.		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

Filed: 2008-12-30

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

CCC INTERROGATORY #1

INTERROGATORY

Please provide an estimate of the incremental annual costs that would be incurred if the LDCs were required to move to a monthly price adjustment mechanism.

RESPONSE

Please see the response to Board Staff Interrogatory #1 at Exhibit IR24, Schedule 1.

Witnesses: I. Abbasi
A. Kacicnik

CCC INTERROGATORY #2

INTERROGATORY

Please provide a detailed description of the potential benefits and costs associated with moving to a mechanism that would adjust the commodity cost of gas every six months. Would the LDCs be supportive of such an approach? If not, why not?

RESPONSE

As outlined at the Company's evidence at Exhibit E1, page 2, Paragraphs 6 to 8 the parties established the current QRAM process to achieve an enhanced reflection of gas supply prices on a regular basis while mitigating large annual adjustments to customer bills.

In Enbridge's view a quarterly price adjustment based upon 12 month forecast period provides appropriate balance between the two objectives of price change frequency and retroactive adjustments to customer bills.

A semi-annual price change would represent a partial return to the methodology used prior to the implementation of QRAM when price volatility in the test year was entirely captured in the PGVA and cleared once a year. Consequently, the Company does not see merits that would warrant introducing a semi-annual price change mechanism.

Witnesses: I. Abbasi
M. Giridhar
A. Kacicnik

CCC INTERROGATORY #4

INTERROGATORY

With respect to the QRAM process what changes could be made to create a more competitive market for energy consumers?

RESPONSE

In the Ontario natural gas market customers have a choice between the regulated supply and direct purchase (i.e., competitive) options. This is reflected in about 40% of Enbridge's customers having direct purchase contracts representing about 60% of the annual volume throughput. Customers generally choose between the two options based on their preference / need for a stable price, and therefore a fixed price contract of a specific duration, or willingness to manage price changes / impacts resulting from the QRAM process. Enbridge is neutral as to the customer election of either option and simply fulfills the service option requirements.

In Enbridge's view, ongoing plain language consumer education about marketplace options and associated pros and cons, rights and obligations, would further increase customer awareness about regulated supply and direct purchase (i.e., competitive) options, as well as differentiation among various competitive options.

Witnesses: M. Giridhar
A. Kacicnik
I. MacPherson

CCC INTERROGATORY #5

INTERROGATORY

How can EGD and Union Gas ensure that the “commodity cost” as set out on their bills is comparable to the offerings provided by retail marketer? Are changes required? If, so please explain what changes should be made?

RESPONSE

EGD’s “commodity cost”, as set out on its bills, reflects the forecasted cost of procuring supply at Empress over a twelve month period as per the Board approved QRAM methodology (i.e., the regulated gas supply option). Retail Marketers tend to offer a fixed price for a term of one, three or five years. Enbridge does not have input into or an oversight of retailers’ offerings or their pricing.

Also, see the response to CCC Interrogatory #4 at Exhibit IR7, Schedule 4.

Witnesses: M. Giridhar
A. Kacicnik
I. MacPherson
D. Small

CCC INTERROGATORY #6

INTERROGATORY

Please explain why a 21-day strip is the optimal way to undertake a gas cost forecast relative to other models,

RESPONSE

Typically a gas supply contract trades for a 21-day period. For example, the October 2008 AECO contract traded as the near month contract from August 28, 2008 to September 26, 2008. Using this time frame is representative of the expected price for a future forecast month.

Witnesses: M. Giridhar
D. Small

CCC INTERROGATORY #7

INTERROGATORY

Please provide, to the extent possible, evidence that the 21-day strip approach is used in other jurisdictions. To the extent is not, what are the most common approaches applied?

RESPONSE

Enbridge has not conducted a survey of other jurisdictions with respect to the 21-day strip approach.

As outlined in Enbridge's evidence at Exhibit E1, page 2, the 21-day strip approach, as part of the QRAM process, was originally established by the parties and then approved by the Board on May 30, 2001 as part of RP-2000-0040 and subsequently modified in RP-2002-0133 and RP-2003-0203.

As noted in the response to CCC Interrogatory #6 at Exhibit IR5, Schedule 6, a gas supply contract typically trades for a 21-day period. Using the 21-day time frame is representative of the expected price for a future forecast month.

Witnesses: M. Giridhar
D. Small

CCC INTERROGATORY #8

INTERROGATORY

Please indicate, specifically, how EGD allocates its invoicing and payment processing costs between the system gas fee and the direct purchase administration fee.

RESPONSE

The incremental costs associated with invoicing and payment processing are allocated between the system gas fee and direct purchase administration fee based on the staffing costs associated with supporting either the system gas or direct purchase function. The costs for the system gas function include receiving invoices, verifying accuracy, and submitting payment. The costs for the direct purchase function include verifying and submitting payment for direct purchase agreements.

Witnesses: J. Collier
A. Kacicnik
I. MacPherson
M. Suarez
B. Vari

CCC INTERROGATORY #9

INTERROGATORY

(E1/p. 51) Please provide the detailed back-up calculations for the new DPAC charge of $75.

RESPONSE

The fixed fee was based on what would be a reasonable annual fee for a pool that only had one account; in most cases this represented the customer type pools.

On an annual basis the fee for a one account pool would be approximately $900 per year which represents a fair and reasonable level of incremental cost effort to support.

The fixed fee represents providing all DPAC services for a single account customer for all customer groups. As the number of customers per pool increases, it was considered that the level of administrative services provided would increase proportionately. This is what the variable account fee recovers.

Witnesses: J. Collier
A. Kacicnik
I. MacPherson
M. Suarez
B. Vari

GAS MARKETER GROUP INTERROGATORY #1

INTERROGATORY

Reference: Page 1, Paragraph 1.

Please provide the documentation in which the Ontario Energy Board determined that stakeholders were "largely satisfied with the existing regulatory system and that the natural gas sector would benefit more from specific improvements than from a transformative change". Please provide the document name, section, and quote.

RESPONSE

The source for Paragraph 1 in Enbridge's evidence is the Ontario Energy Board's Natural Gas Forum ("NGF") report titled:

"Natural Gas Regulation in Ontario: A Renewed Policy Framework", issued on March 30, 2005.

Please see "Context of the Current Policy Review" section on page 10 of the Board's NGF report for the Board's conclusion referenced in the question above:

> The Board notes that stakeholders are largely satisfied with many of the current regulatory arrangements, and it has determined that the sector will benefit more from specific, incremental structural improvements than from transformative change.

Witnesses: A. Kacicnik

GAS MARKETER GROUP INTERROGATORY #3

INTERROGATORY

Reference: Page 3, Paragraphs 9-11.

For each of the subcomponents which form the quarterly gas charge, including riders, please provide a full listing of what the price or account balances were on a monthly basis for the last three years. Please also indicate whether any portion of the monthly price or account balance was partly formed by a carry over from previous time periods.

RESPONSE

The attachments represent the projected year-end balance filed as part of the January 1 QRAM for the last three years.

Attachment 1 is the projected December 31, 2008 PGVA balance as filed in the January 1, 2009 at EB-2008-0348, Exhibit Q1-3, Tab 1, Schedule 2, page 3.

Attachment 2 is the projected December 31, 2007 PGVA balance as filed in the January 1, 2008 at EB-2007-0897, Exhibit Q1-3, Tab 1, Schedule 2, page 2.

Attachment 3 is the projected December 31, 2006 PGVA balance as filed in the January 1, 2007 at EB-2006-0288, Exhibit Q1-3, Tab 1, Schedule 2, page 2.

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

ENBRIDGE GAS DISTRIBUTION INC.
PROJECTED YEAR-END PGVA BALANCE
TWELVE MONTHS ENDED DECEMBER 31, 2008

		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 10	Col. 11
Item #	Month	Purchase Cost	10^3m^3	$\$/10^3m^3$	Reference Price	Unit Rate Difference	Forecast Month of PGVA	Forecast YTD PGVA	Forecast Rollover	Inventory Adjustment	Forecast Rider C	Forecast YTD PGVA with Inventory Adjustment
1.1	2007 Forecast PGVA Balance Rollover								(137,659.0)	-	-	(137,659.0)
1.2	January 1/08 Inventory Re-evaluation									32,618.4	-	(105,040.6)
1.3	January	156,258.1	535,200.2	291.962	303.215	(11.253)	(6,022.7)	(6,022.7)	-	-	10,431.3	(100,632.0)
1.4	February	123,950.0	370,446.7	334.596	303.215	31.381	11,625.0	5,602.3	-	-	19,864.6	(69,142.4)
1.5	March	232,215.6	646,643.1	359.109	303.215	55.894	36,143.7	41,746.0	-	-	19,432.0	(13,566.8)
1.6	April	128,340.3	344,310.4	372.746	340.684	32.062	11,039.3	52,785.3	-	(27,782.4)	15,702.7	(14,607.1)
1.7	May	136,743.9	331,913.5	411.987	340.684	71.303	23,666.3	76,451.6	-	-	11,860.2	20,919.4
1.8	June	168,245.1	376,599.0	446.749	340.684	106.065	39,943.8	116,395.4	-	-	8,781.0	69,644.2
1.9	July	169,881.1	356,354.6	476.719	438.790	37.929	13,516.3	129,911.7	-	(127,409.0)	3,210.2	(41,038.4)
1.10	August	150,810.4	438,182.0	344.173	438.790	(94.617)	(41,459.4)	88,452.2	-	-	1,148.2	(81,349.6)
1.11	September	169,216.4	474,940.5	356.290	438.790	(82.500)	(39,182.8)	49,269.5	-	-	1,005.9	(119,526.4)
1.12	October	155,860.1	510,660.3	305.213	387.103	(81.890)	(41,818.1)	7,451.3	-	113,674.7	(1,986.5)	(49,656.4)
1.13	November	106,648.1	330,982.8	322.216	387.103	(64.887)	(21,476.4)	(14,025.1)	-	-	(6,588.1)	(77,720.9)
1.14	December	132,356.0	403,703.1	327.855	387.103	(59.248)	(23,918.8)	(37,943.9)	-	-	(10,113.5)	(111,753.1)
	Sub-Total	**1,830,525**	**5,119,936.1**	**357.529**			(37,943.9)	(37,943.9)	(137,659.0)	(8,898.2)	72,748.0	(111,753.1)
	Impact of TCPL Toll Change on System Supply											-
												(111,753.1)
	January 1/08 Inventory Revaluation			1,620,263.9	20.132			32,618.4				
	April 1/08 Inventory Revaluation			741,475.0	(37.469)			(27,782.4)				
	July 1/08 Inventory Revaluation			1,298,687.0	(98.106)			(127,409.0)				
	October 1/08 Inventory Revaluation			2,199,289.8	51.687			113,674.7				

ENBRIDGE GAS DISTRIBUTION INC.
Projected Year-end PGVA Balance
Twelve Months Ended December 31, 2007

Item #	Month	Col. 1 Purchase Cost $(000)'s	Col. 2 10^3m^3	Col. 3 Unit Rate $/10^3m^3	Col. 4 Reference Price $/10^3m^3	Col. 5 Unit Rate Difference $/10^3m^3	Col. 6 Forecasted Month of PGVA $(000)'s	Col. 7 Forecasted YTD PGVA $(000)'s	Col. 8 Forecasted Rollover	Col. 9 Inventory Revaluation $(000)'s	Col. 10 Forecasted Rider "C" $(000)'s	Col. 11 Adjusted YTD PGVA $(000)'s
1.1	2006 Forecast PGVA Balance Rollover								(106,597.0)			(106,597.0)
1.2	January 1/07 Inventory re-valuation									61,486.1		(45,110.9)
1.3	January	100,941.7	319,487.3	315.949	349.047	(33.098)	(10,574.0)	(10,574.0)			4,099.2	(51,585.7)
1.4	February	110,053.1	304,633.1	361.264	349.047	12.217	3,722.0	(6,852.0)			9,759.2	(38,104.5)
1.5	March	178,404.4	563,034.7	316.862	349.047	(32.185)	(18,121.0)	(24,973.0)			7,841.2	(48,384.3)
1.6	April 1/07 Inventory re-valuation									(8,405.7)		(56,790.0)
1.7	April	165,906.6	538,349.0	308.177	362.982	(54.805)	(29,504.0)	(54,477.0)			14,794.8	(71,499.2)
1.8	May	106,269.1	345,827.4	307.289	362.982	(55.693)	(19,260.0)	(73,737.0)			11,537.0	(79,222.2)
1.9	June	109,818.4	358,462.9	306.359	362.982	(56.623)	(20,297.0)	(94,034.0)			7,086.9	(92,432.4)
1.10	July	106,837.6	381,851.3	279.788	362.982	(83.194)	(31,768.0)	(125,802.0)			7,719.5	(116,480.8)
1.11	August	94,104.8	371,315.7	253.436	362.982	(109.546)	(40,676.0)	(166,478.0)			9,418.9	(147,737.9)
1.12	September	97,681.8	425,152.3	229.757	362.982	(133.225)	(56,641.0)	(223,119.0)			8,986.2	(195,392.8)
1.13	October 1/07 Inventory re-valuation									87,165.3		(108,227.5)
1.14	October	98,302.9	402,376.5	244.306	323.347	(79.041)	(31,804.0)	(254,923.0)			5,428.2	(134,603.2)
1.15	November	128,367.3	464,958.9	276.083	323.347	(47.264)	(21,976.0)	(276,899.0)			12,417.2	(144,162.0)
1.16	December	121,032.4	412,848.0	293.165	323.347	(30.182)	(12,461.0)	(289,360.0)			18,964.0	(137,659.0)
	Sub-Total	1,417,720.1	4,888,297.3	290.023				(289,360.0)	(106,597.0)	140,245.7	118,052.3	(137,659.0)
	January 1/07 Inventory Revaluation Credit			1,883,476.2	32.645			61,486.1				
	April 1/07 Inventory Revaluation Credit			603,207.5	(13.935)			(8,405.7)				
	July 1/07 Inventory Revaluation Credit			1,354,388.6	0.000			-				
	October 1/07 Inventory Revaluation Credit			2,199,182.3	39.635			87,165.3				

ENBRIDGE GAS DISTRIBUTION INC.
Projected Year-end PGVA Balance
Twelve Months Ended December 31, 2006

Item #	Month	Col. 1 Purchase Cost $(000)'s	Col. 2 10^3m^3	Col. 3 Unit Rate $/$10^3m^3$	Col. 4 Reference Price $/$10^3m^3$	Col. 5 Unit Rate Difference $/$10^3m^3$	Col. 6 Forecasted Month of PGVA $(000)'s	Col. 7 Forecasted YTD PGVA $(000)'s	Col. 8 Prior Year Rollover $(000)'s	Col. 9 Inventory Revaluation $(000)'s	Col. 10 Rider "C" $(000)'s	Col. 11 Adjusted YTD PGVA $(000)'s
1.1	September 05 Rollover								2,800.7			2,800.7
1.2	December 05 Rollover								97,272.7			100,073.4
1.3	January 1/06 Inventory re-valuation									(166,678.1)		(66,604.7)
1.4	January	175,682.3	373,024.5	470.967	484.195	(13.228)	(4,934.0)	(4,934.0)			8,187.1	(63,351.6)
1.5	February	126,642.1	300,532.2	421.393	484.195	(62.802)	(18,874.0)	(23,808.0)			13,640.9	(68,584.7)
1.6	March	109,287.7	271,916.3	401.917	484.195	(82.278)	(22,373.0)	(46,181.0)			13,336.1	(77,621.6)
1.7	April 1/06 Inventory re-valuation									71,756.7		(5,864.9)
1.8	April	94,544.5	307,407.8	307.554	399.582	(92.028)	(28,290.0)	(74,471.0)			8,414.4	(25,740.5)
1.9	May	95,056.8	313,532.5	303.180	399.582	(96.402)	(30,225.0)	(104,696.0)			4,340.3	(51,625.2)
1.10	June	87,183.0	305,332.7	285.534	399.582	(114.048)	(34,822.0)	(139,518.0)			3,058.2	(83,389.0)
1.11	July 1/06 Inventory re-valuation									24,411.5		(58,977.4)
1.12	July	87,533.6	307,666.5	284.508	381.692	(97.184)	(29,900.0)	(169,418.0)			5,712.0	(83,165.4)
1.13	August	108,474.7	360,304.6	301.064	381.692	(80.628)	(29,051.0)	(198,469.0)			7,776.7	(104,439.6)
1.14	September	112,135.7	409,101.5	274.102	381.692	(107.590)	(44,015.0)	(242,484.0)			7,774.1	(140,680.5)
1.15	October 1/06 Inventory re-valuation									-		
1.16	October	111,932.2	493,176.8	226.962	381.692	(154.730)	(76,309.0)	(318,793.0)			23,048.8	(193,940.7)
1.17	November	172,232.9	505,310.5	340.846	381.692	(40.846)	(20,640.0)	(339,433.0)			46,270.4	(168,310.3)
1.18	December	174,617.9	482,648.9	361.791	381.692	(19.901)	(9,605.0)	(349,038.0)			71,318.3	(106,597.0)
	Sub-Total	1,455,323.4	4,429,954.8	328.519				(349,038.0)	100,073.4	(70,509.9)	212,877.4	(106,597.0)

January 1/06 Inventory Revaluation Credit	1,902,109.9	(87.628)	(166,678.1)
April 1/06 Inventory Revaluation Credit	848,057.4	84.613	71,756.7
July 1/06 Inventory Revaluation Credit	1,364,523.3	17.890	24,411.5
October 1/06 Inventory Revaluation Credit	2,112,011.4	0.000	-

GAS MARKETER GROUP INTERROGATORY #4

INTERROGATORY

Reference: Page 3, Paragraph 10

Enbridge currently adjusts its annualized revenue requirement on the reference price resulting from the QRAM. What impacts on the revenue requirement would there be if Enbridge moved to a monthly price for gas? In responding, please indicate all analysis and assumptions.

Has Enbridge considered using any other methods to set adjust its revenue requirement? Please provide the details of the forecasted revenue requirement versus actual revenue for the past three years.

RESPONSE

As outlined in the Company's evidence in relation to Issue 5, regardless of the frequency of a forecast adjustment mechanism in relation to changes in gas prices, the types of impacts within the revenue requirement would remain as a cost to the Company which are driven by changing gas prices. If Enbridge were to move to a monthly adjustment mechanism it would still be faced with the same base type of revenue requirement related cost impacts that it adjusts within the quarterly adjustment mechanism.

Enbridge does not compile data of actual and forecast annual revenue requirements specific to the various changes in gas prices that occur on a quarterly basis and their impacts within related carrying costs.

Witnesses: K. Culbert
M. Giridhar
A. Kacicnik

GAS MARKETER GROUP INTERROGATORY #5

INTERROGATORY

Reference: Page 9, Paragraph 31.

By looking at the 12 month cost of gas for QRAM setting, there seems to be an implied cost/ benefit of storage. Does EGD agree that this is the case? If not, why not?

RESPONSE

The 12 month cost of gas for QRAM reflects the purchasing pattern for system supplies, including load balancing for DP customers, which is made possible due to the availability of storage. This benefit is provided to system gas customers and direct purchase customers.

Witnesses: M. Giridhar
D. Small

GAS MARKETER GROUP INTERROGATORY #8

INTERROGATORY

Reference: Page 11, Paragraph 36.

Would EGD agree that shorter time frame setting of the regulated rate (i.e. MRAM) allows for more accurate matching of actual commodity and gas service costs (transportation and storage) to the actual customers receiving default service? If not, why not?

RESPONSE

EGD does not agree. As noted in Exhibit E1, page 9, Paragraph 31, EGD's monthly purchases do not equal the monthly consumption of its customers, rather annual purchases equal the annual consumption of its customers. Assuming that all gas is purchased in the month that it is consumed would be unrepresentative of how gas is purchased for the actual customers receiving default service.

Witnesses: M. Giridhar
D. Small

GAS MARKETER GROUP INTERROGATORY #10

INTERROGATORY

Reference: Page 12, Paragraph 37.

Please provide a detailed estimate of the costs alluded to in this section for EGDI to change from a Quarterly Rate Adjustment Mechanism (QRAM) to a Monthly Rate Adjustment Mechanism (MRAM). Please also indicate which specific changes would be necessary for each of the following: cost allocation methodology, rate design methodology, IT system billing and communication processes.

RESPONSE

Please see the response to Board Staff Interrogatory #1 at Exhibit IR24, Schedule 1.

Witnesses: I. Abbasi
A. Kacicnik

GAS MARKETER GROUP INTERROGATORY #11

INTERROGATORY

Reference: Page 14, Paragraph 42.

Does Enbridge agree that any deviation from the Alberta price is due to decisions made by the utility, and that such decisions should be reviewed for prudency? If not, why not?

RESPONSE

EGD does not agree with the above statement.

EGD uses a Board approved methodology which is consistent with its procurement practices to derive an Alberta price. If the Ontario reference price uses a different methodology to arrive at an Alberta price it would have consequences for the current cost allocation and rate design methodologies which are also approved by the Board.

Witnesses: M. Giridhar
A. Kacicnik
D. Small

GAS MARKETER GROUP INTERROGATORY #12

INTERROGATORY

Reference: Page 15, Paragraph 44.

a) Does Enbridge believe that an Ontario-wide reference price would allow for greater transparency into Utility procurement practices, and if so why? If not, why not?

b) How would an Ontario Reference Price create a disconnect between a distributor's procurement practice and pricing? Please identify the specific disconnects that Enbridge perceive and what impacts they would have.

c) What impacts would an Ontario Reference Price have on equity between service offerings? In responding to this question, please indicate what Enbridge meant in using the term 'service offerings'.

d) What impacts would an Ontario Reference Price have on retroactive billing? In responding to this question, please indicate all components of the customer's bill that would be impacted, including any subcomponents of the accounts that currently comprise the QRAM. In responding to this question, please clearly indicate how Enbridge is assuming an Ontario Reference Price would be defined and all assumptions of its makeup.

RESPONSE

a) EGD's procurement practices are transparent and addressed in evidence filed with the Board in each rate proceeding. Since geography, physical connectivity and customer load profile dictate each utility's procurement costs, a single Ontario wide reference price applied across Ontario utilities would reduce transparency by creating a disconnect between procurement and pricing.

b) See a) above

c) The term service offerings refers to sales, Western bundled T and Ontario bundled T services. EGD's gas portfolio is designed to procure the commodity for its sales customers, transport for its sales and Western T customers and load balancing for sales, Western T and Ontario T customers. EGD uses a Board approved methodology to allocate the cost of its gas portfolio to these services. For example,

Witnesses: M. Giridhar
D. Small

sales customers pay a commodity charge based on an Empress price. Sales and Western T customers pay a transport cost based on the cost of transporting gas to the franchise area. Sales, Western T and Ontario T customers pay load balancing charges based on the cost of Ontario seasonal and peaking supplies in excess of commodity and average transportation costs. If the Ontario Reference Price deviates from the Company's procurement cost, it would distort the equitable allocation of costs between the different services.

d) If the Ontario Reference Price deviates from the distributor's procurement cost, it would result in additional dollars in the PGVA. This would result in greater retroactive billing as the PGVA captures variances in the commodity, transport and load balancing costs.

Witnesses: M. Giridhar
D. Small

GAS MARKETER GROUP INTERROGATORY #13

INTERROGATORY

Reference: Page 18, Paragraph 53.

Please provide any other evaluations done on alternate clearing frequencies for the PGVA. Please advise if EGD sees any merits in matching the clearing frequency to the rate setting frequency, and if so why? If not, why not?

RESPONSE

EGD is mindfull of harmonization of the methodologies of Union and EGD, whenever possible. Therefore, EGD analysed the adoption of Union's methodology of clearing the PGVA on a rolling 12 month basis. EGD would only see merits in matching the clearing frequency with the rate setting frequency if the rate setting frequency was continued to be based on a 12 month forecast for the reasons stated in its evidence at Exhibit E1, page 9, Paragraph 31.

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

GAS MARKETER GROUP INTERROGATORY #14

INTERROGATORY

Reference: Page 21, Paragraph 62-64.

a) Would carrying costs be reduced for Enbridge if transportation and storage were to be unbundled, and retailers were allowed access to do there own balancing? If not, why not?

b) How are these carrying costs factored into the regulated rate?

c) Does EGD deem it appropriate to allow Retailers to manage these costs for themselves, given the large percentage of core customers they serve? If not, why not?

RESPONSE

a) Unbundling of rates and services shifts (to a large extent, but not completely as Enbridge would have to stand by and fulfill its dual roles of the system operator and supplier of the last resort) obligations, responsibilities and cost incurrence associated with the provision of a (unbundled) service from the utility onto the customer or their gas vendor.

Through a regulated bundled service the utility assumes the responsibility for and incurs the cost of providing the service. The utility then recovers the costs of its services through the Board-approved rates. With unbundling, the responsibility and cost incurrence for the unbundled service is transferred onto the customer or their gas vendor. While costs incurred by the customer or their gas vendor for the unbundled service may not be the same as costs incurred by Enbridge under a bundled scenario, the costs for such a service would be carried by the customer or the customer would pay their gas vendor as per their contractual arrangement. It is also important to note that the utility has the dual obligation of the system operator and supplier of the last resort and, consequently, would incur costs to maintain system integrity/reliability and to ensure the system demand is met each day, including peak day demand.

Witnesses: J. Collier
K. Culbert
M. Girdhar
A. Kacicnik
M. Suarez

Accordingly, Enbridge's carrying costs would be reduced as compared to the current level, but costs to the customer may not be reduced.

b) Gas cost working cash related carrying costs are recovered through the gas supply charge which is paid by system gas customers only. Carrying costs of gas in inventory and tax related impacts are recovered through the load balancing charges which are paid by all system gas and direct purchase bundled customers.

c) With the current level of unbundling retailers themselves manage gas cost working cash related carrying costs. Unbundling of load balancing and storage for bundled general service (i.e., mass market) customers is outside the scope of this proceeding.

Witnesses: J. Collier
K. Culbert
M. Girdhar
A. Kacicnik
M. Suarez

GAS MARKETER GROUP INTERROGATORY #15

INTERROGATORY

Reference: Page 28, Paragraph 89.

> Please elaborate on and provide a proposal for simplified application, timeline and communications processes that would facilitate more frequent rate changes than QRAM. Please include the specific actions that will need to be taken to expedite processes and decisions to modify the current QRAM process.

RESPONSE

Enbridge does not support higher than quarterly price change frequency.

The Company notes however if the Board finds that a higher than quarterly (i.e., QRAM) price change frequency is appropriate, then the current QRAM application requirements, associated timeline, as well as customer communication process, would need to be greatly simplified to accommodate the higher frequency of price changes.

Witnesses: J. Collier
A. Kacicnik

GAS MARKETER GROUP INTERROGATORY #16

INTERROGATORY

Reference: Pages 29-30, Paragraphs 90-96.

a) Please explain the rationale for the lead time indicated (21 day strip ending 30 days prior to QRAM effective date), in light of recent volatility in the wholesale gas market.

b) Would EGD agree that a price reported closer to the delivery time period would most likely be more reflective of the value of physical gas delivered under the period in question? If not, why not?

c) Would EGD agree that Dawn is a liquid trading hub reflective of the cost of delivered gas (transportation adjusted to delivery in each utility franchise area)?

d) Does EGD believe there should be a mechanistic approach using NYMEX contract settlement as the marker price and take mid month basis marks to adjust for the utility supply mix? If not, why not?

e) Is it possible to report the NYMEX settles as the prompt month expires (3 days) prior to flow?

f) Would Enbridge agree that the primary drivers for using the current lead time are related to the timing of the regulatory approvals and notice periods in the current QRAM process?

RESPONSE

a) Current processes require 45 days from start to finish to implement a QRAM price change for a specific effective date. EGD is hopeful that with process improvements the timeline can be reduced to 30 days. EGD still believes however, that the Reference Price should still be based on a 21-day average of forecasted monthly prices because it is representative of the timeframe that a contract is traded for.

Witnesses: M. Giridhar
A. Kacicnik
D. Small

b) As discussed on page 9, paragraph 31 of its evidence, EGD does not believe that the market price of gas in one particular month is reflective of the value of gas consumed by a customer in that particular month. Customers in Ontario have the benefit of storage and EGD plans its gas supply portfolio accordingly.

c) While Dawn has developed over the years such that it has become a very active trading hub, EGD submits that there is not adequate supplies available at Dawn to meet its' entire demand. Even if this were the case there is not enough firm transportation available from Dawn to the CDA and to the EDA. EGD believes that a Utility should maintain a gas supply portfolio that is geographically diverse to eliminate the reliance upon one particular transporter or supply basin. EGD also believes that the role of the Utility is to be able to provide firm service to its customers (except for those that opt for interruptible service) and this cannot be met unless it has, at its disposal, firm transportation contracts to the franchise area.

d) No. As discussed in its' evidence, EGD believes that its rates should be based on the forecasted costs of its' supply portfolio and as such should capture the forecasted indices for all the pertinent price points including the associated transportation costs. This will ensure that rates are set based upon the Board approved cost allocation and rate design and that the subsequent clearing of the PGVA can follow that same cost allocation methodology.

e) Not withstanding that using Nymex is inconsistent with the need to reflect forecast gas costs in rates that are consistent with procurement practice, the timing proposed in this question would not allow sufficient time for preparation of evidence and schedules, regulatory approval, billing implementation and customer communication.

f) See e) above.

Witnesses: M. Giridhar
A. Kacicnik
D. Small

GAS MARKETER GROUP INTERROGATORY #17

INTERROGATORY

Reference: Page 36, Paragraph 118

Please explain how the tools provided by EGD are appropriate for Gas Vendors to manage the customer mobility impacts of GDAR, given that such tools are restricted during the peak winter demand months and the late storage injection season.

RESPONSE

As outlined in the Company's evidence in paragraph 125 and 131, the Company proposes to adopt MDV reestablishment and weather normalized MDV establishment. These two additional mechanisms will help address the customer mobility impacts to a large degree since it will reduce over and under deliveries caused by customer mobility.

Witnesses: M. Giridhar
I. MacPherson
B. Manwaring
D. Small

GAS MARKETER GROUP INTERROGATORY #18

INTERROGATORY

Reference: Page 36, Paragraph 119

a) Please provide an approximate duration in hours or days that that defines the "short notice" reference to replace deliveries on interrupted Suspension as discussed in this paragraph.

b) Would Enbridge consider imposing financial penalties on Direct Purchase customers for failure to deliver on interrupted Suspension?

RESPONSE

a) As the reason for interrupting a Suspension would likely reflect current supply/demand conditions, required actions would be anticipated based on the day ahead gas market. Therefore, in absence of further study, a 24 hour time frame would be an anticipated notice period.

b) There are financial penalties for failing to comply with a contracted requirement. Similar treatment would be envisioned in these cases.

Witnesses: M. Giridhar
A. Kacicnik
I. MacPherson
B. Manwaring
D. Small

GAS MARKETER GROUP INTERROGATORY #19

INTERROGATORY

Reference: Page 37, Paragraphs 122

Is it possible that more frequent balancing could result in reduced cost recovery from ratepayers? If not, why not?

RESPONSE

No. EGD balances all bundled customers on a daily basis for both planned and unplanned consumption. To the extent that load balancing requires gas purchases at peak prices, the return of the molecule at a subsequent time period (even if more frequent than annually) would not have an appreciable effect on customer rates.

Witnesses: M. Giridhar
A. Kacicnik
I. MacPherson
B. Manwaring
D. Small

GAS MARKETER GROUP INTERROGATORY #20

INTERROGATORY

Reference: Page 37, Paragraphs 123

Considering the mobility impacts of GDAR, does EGD believe that more frequent balancing of the system would provide greater efficiency, matching supply more closely with demand and costs, by customer and retailer? If not, why not?

RESPONSE

No. See the responses to Gas Marketer Group Interrogatories #17 and #19 at Exhibit IR8, IR14, IR18, IR19, Schedules 17 and 19, respectively.

Witnesses: M. Giridhar
A. Kacicnik
I. MacPherson
D. Small

GAS MARKETER GROUP INTERROGATORY #21

INTERROGATORY

Reference: Page 38, Paragraph 125

Please provide a detailed breakdown of the "large scale changes" to ENTRAC, contracts, processes, policies, and tariffs required for MDV re-establishment and multi-point balancing.

RESPONSE

In addition to a number of other business requirements, EnTRAC manages the following:

- facilitates the contract administration process
- processes transactions submitted by gas vendors / customers (creation of pools and price point groups, enrollments, transfers and drops) in compliance with GDAR
- establishes the delivery requirement for each pool based upon gas vendor and customer elections
- maintains a Banked Gas Account (BGA) report for each pool
- manages all gas nomination requests
- processes load balancing requests
- tracks all deliveries related to customers attached to pools
- tracks all consumptions volumes related to customers attached to pools
- tracks all gas vendor charges billed in relation to customers attached to pools
- monitors contractual compliance of pools in relation to their gas delivery agreements
- processes BGA disposition requests
- processes and directs payments / remittances to gas vendors / customers
- calculates and invoices (directly or through an interface to the customer billing system) all gas delivery agreement non-compliance charges

All of these business requirements are interrelated and provide a comprehensive solution through user interface screens, engines, reports, system interfaces and in some cases internet transport protocols. To accommodate multi-point balancing, MDV re-establishment and weather normalized MDV's would require significant change to a

Witnesses: I. Abbasi
B. Manwaring

significant portion of the integrated solution components. The analysis to date indicates that approximately 30 screens, 20 engines and 10 reports will require changes or development.

In relation to MDV re-establishment and multi-point balancing, the large scale changes required to EnTRAC involve, but are not limited to, the following:

1. Management of Election Process for Balancing Options

   EnTRAC will be modified to accommodate both Balance Point Options of EGD determined or Customer determined which will be elected at the Pool Level.

2. Checkpoint Value Determination

   An engine is required to calculate the check point value determination which will incorporate;
   - billed consumption to date
   - forecasted consumptions to the check point
   - forecasted weather variance
   - changes to pool composition
   - nominations and accepted load balancing transactions

3. Banked Gas Account ("BGA") Forecasts

   In addition to the current monthly BGA forecasts and final BGA balance at the end of each contract year, EnTRAC will be modified to provide volumetric forecasts for additional balancing points.

   BGA will need to be modified to accommodate the MDV for pools potentially changing on a monthly basis and the forecasting model calculations will need to be significantly modified.

4. Communications

   A mechanism is required to communicate, alert and provide directions of required actions to gas delivery agreement holders and required time lines for checkpoint balancing.

Witnesses: I. Abbasi
B. Manwaring

5. Processing Load Balancing Requests

   It is anticipated that there will be potential changes to the processing of load balancing requests to accommodate new considerations relevant to multi-point balancing.

6. Compliance Monitoring

   Revise the compliance engine to monitor the resultant activity at the deadline balancing points. EnTRAC will be required to perform actions triggered from the resultant activity such as BGA balance transfers, invoicing of penalties, and/or Gas Sale/Purchases.

7. Remittance Engine and Report Engines (Funds Imbalance and Invoice Remittance Statements)

   The remittance engine will require modification to accommodate the application of charges and amounts remitted in relation to multi-point balancing. The Funds Imbalance Report and Remittances Statements will also require modifications to include additional information / charge types. The engine that calculates the weighted average price used in the remittance process which has a dependency on MDV will require modifications.

8. Billing System Interface

   If charges need to be applied to customer invoices, EnTRAC upon calculating billing values will require an interface mechanism in order to communicate applicable charges to the billing system and correctly apply them to appropriate general ledger accounts.

9. Administration and Management Reports

   Additional reports will be required to manage the multi-point balancing process for monitoring and execution, as well as MDV re-establishment. For example: with the MDV's for pool's changing more frequently the assignment of FT capacity on TCPL has the potential of changing on a monthly basis. Reports will be required to trigger the updating of TCPL's Dovetail system with the changes to the monthly assignments of Enbridge capacity to third party shippers on TCPL.

Witnesses: I. Abbasi
B. Manwaring

10. MDV Establishment Engine and Screens

    The MDV Establishment Engine will need to be modified to accommodate the business rules applicable to the periodic re-establishment of MDV for pools once triggers are reached (such as pool account composition changes that have reached an agreed threshold).

11. Pool Composition Engine and Report

    The Pool Composition Report and engine will require modifications in order to generate additional Pool Composition Reports to coincide with and provide the lower level detail (such as account composition and account contribution to MDV calculation) supporting the re-established MDV for a Pool.

12. Nomination Engine and Screens

    All screens and engines relating to nomination management will need to be revised to accommodate the periodic change to the MDV of pools. Alerts and message triggers will require modification.

13. Weather Normalization Engine

    Create a data feed mechanism and incorporate a Weather Normalization into the MDV establishment process/calculation.

14. Database Modifications, Data Migration and Archiving Procedures

    Significant changes to the EnTRAC database will be required to accommodate the additional data related to MDR re-establishment, weather normalization data, and multi-point balancing.

.

Witnesses: I. Abbasi
B. Manwaring

GAS MARKETER GROUP INTERROGATORY #22

INTERROGATORY

Reference: Page 38, Paragraph 126

Please confirm/ deny that the $8.5M implementation costs alluded to in this paragraph include both weather normalized MDV re-establishment and multi-point BGA balancing.

RESPONSE

Confirmed, that the $8.5M implementation costs alluded to in this paragraph include both weather normalized MDV re-establishment and multi-point BGA balancing.

Witnesses: I. Abbasi
B. Manwaring

GAS MARKETER GROUP INTERROGATORY #23

INTERROGATORY

Reference: Page 38, Paragraph 126

Please provide a detailed breakdown of the $8.5M costs for the standardization of load balancing mechanisms between Union and Enbridge.

RESPONSE

The following is based on estimates that would result from the adoption of a multi point balancing model. The estimates are high level and the list is not to be interpreted as exhaustive or complete as it was prepared in absence of a formal/detailed evaluation.

Design and Development Including scoping study, transaction rules, programming development, test and warranty	$5,000,000
Infrastructure Changes to internal processes, documents, staffing, controls (Sox), contracts, training and testing, synchronization with other programs	$1,250,000
3rd Party Development, Training and Communications Any impacts from integration and testing with other systems and/or programs such as SAP	$1,250,000
Project Management	$500,000
Contractor Expenses Travel, living, administration	$500.000
Sum	$8,500,000

Witnesses: I. Abbasi
B. Manwaring

GAS MARKETER GROUP INTERROGATORY #24

INTERROGATORY

Reference: Page 38, Paragraph 126

Please explain why $8.5M worth of costs are required to implement multi-point balancing when this process is already done on the anniversary of the contract? Why does facilitating this process at minimum 2 more times per year cause such costs to be incurred?

RESPONSE

While the processes appear to have similar outcomes in truing up differences between estimated and actual consumptions, the functions driven from check points and the contract anniversary are very different and would require the creation of new logic and support.

Downstream functions stemming from the check point requirements would also be new, (please refer to GMG Interrogatory #21 at Exhibit IR8, IR14, IR18, IR19, Schedule 21 for detail) so would require design and testing. Any/all changes would be required to successfully interface with other customer service and support systems that take in metering/consumption information and allow billing.

Recent projects undertaken that have required changes to EnTRAC (such as GDAR and CIS) have proven to be comprehensive in nature. Standardization of the BGA management process would have many of the same requirements of resources as previous projects.

Witnesses: I. Abbasi
I. MacPherson
B. Manwaring

GAS MARKETER GROUP INTERROGATORY #25

INTERROGATORY

Reference: Page 38, Paragraph 127

Please provide a detailed breakdown of the $3.7M cost for weather normalized MDV establishment/ re-establishment.

RESPONSE

The following is based on estimates that would result from adoption of an MDV reestablishment process. These estimates are high level and the list is not to be interpreted as exhaustive or complete as it was prepared in absence of a formal/detailed evaluation.

Design and Development Including scoping study, transaction rules, hardware and software development including development of an appropriate weather normalization program	$2,650,000
Infrastructure Changes to internal processes, documents, contracts	$550,000
Project Management	$250,000
Contractor Expenses Travel, living, administration	$250.000
Sum	$3,700,000

Witnesses: I. Abbasi
B. Manwaring

GAS MARKETER GROUP INTERROGATORY #26

INTERROGATORY

Reference: Page 39, Paragraph 130

a) Considering that Direct Purchase (DP) customers deliver 60% of the supply volumes into the province, and Enbridge controls whether a DP customer can suspend deliveries, please advise if it is possible for Enbridge to draft DP supply.

b) Please advise if system customers, through EGD, experience a benefit/ cost by balancing all customers. If not, why not?

RESPONSE

a) No, for the simple fact that the DP customers continue to consume. In addition, the time of year that EGD does not allow suspensions (usually winter), EGD supplements the DP supply to these customers (and all other bundled ratepayers for that matter) with gas from its load balancing tools.

b) As noted in Enbridge's evidence at Exhibit E1, Paragraph 40, page 13, the supply portfolio serves to meet the twin obligations of the distributor - default supplier to system gas customers (i.e., regulated supply option) as well as system operator for all customers on its system. Because both system and DP customers are treated in the same fashion with respect to the balancing service and recovery of its costs, there is no asymmetrical benefit/cost conveyed to either group of bundled customers.

Witnesses: M. Giridhar
A. Kacicnik
I. MacPherson
B. Manwaring
D. Small

GAS MARKETER GROUP INTERROGATORY #27

INTERROGATORY

Reference: Page 50, Paragraph 173

a) Please provide a detailed breakdown of the $3.18M direct purchase management costs referred to in this paragraph using the incremental accounting approach

b) Please also provide the calculation that translates these costs into the new recovery rates for DPAC charges proposed in paragraph 178.

c) Please explain why Enbridge's proposed monthly account fee of $0.26 is $0.07 higher than Union's fee.

d) Please provide the break down of all elements comprising cost of system gas of $0.88 million using the incremental accounting approach.

e) Please provide the break down of all elements comprising the 2009 estimated system gas fee of $1.14 million using the incremental accounting approach.

f) Please provide the break down of all elements comprising the direct purchase management costs of $1.56 million using the incremental accounting approach.

RESPONSE

a) The breakdown of the $3.18M direct purchase management costs by function for 2009 based on the incremental costing approach is as follows:

	Incremental Cost Estimate for 2009	
	Direct Purchase	
Contract Management	$	1,370,425
Nominations	$	261,368
Invoicing & Payment Processing	$	68,384
Demand Forecasting & Supply Planning	$	36,803
Direct Purchase Billing Adjustments	$	631,123
Total incremental costs for activities	$	2,368,104
Fringe benefits for labour component of incremental costs	$	811,241
TOTAL	$	3,179,345

Witnesses: J. Coillier
A. Kacicnik
I. MacPherson
M. Suarez
B. Vari

b) The cost recovery of the $3.18 M is provided below:

	$ M
1132 Pools @ $75/mth	$1.00
701155 Accounts @ $0.26/mth	$2.18
Total	$3.18

As part of each annual rate adjustment application, the number of pools and accounts levels will be updated. The fixed fee will remain at $75. The amount recovered through the fixed fee will be updated based on the forecast number of pools. The variable fee will be adjusted to reflect the remaining amount to be recovered. The remaining amount will be divided by the forecast number of accounts to arrive at the cost per account (i.e., per account fee).

c) The Company's proposed DPAC structure is set to recover its forecast of incremental costs for this function. The amount of incremental costs recovered through the base charge equals base charge times the forecast number of pools. The remaining costs are recovered based on the variable charge which is determined based on the forecast number of accounts. The account fees of Enbridge and Union Gas are not the same due to the different number of pools and accounts between the two utilities, and different levels of incremental costs that are recovered through the DPAC charges.

d) The functions identified as system gas related pertain to the roles and responsibilities which were performed at that time. The grouping of the responsibilities into functions may not be directly comparable to the 2009 grouping of functions however the overall incremental cost amount is comparable. The breakdown of the existing level of incremental costs for the system gas functions is as follows:

Witnesses: J. Coillier
A. Kacicnik
I. MacPherson
M. Suarez
B. Vari

	Incremental Cost Estimate for 2002	
	System Gas	
Gas Acquisition	$	270,460
Risk Management	$	68,800
Contract Management	$	86,818
Nominations	$	33,907
Invoicing & Payment Processing and reporting	$	142,921
Supervision	$	89,537
Billing	$	6,157
Total incremental costs for activities	$	698,600
Fringe benefits for labour component of incremental costs	$	186,212
TOTAL	$	884,812

e) The breakdown of the $1.14M system gas costs by function for 2009 based on the proposed incremental costing approach is as follows:

	Incremental Cost Estimate for 2009	
	System Gas	
Gas Acquisition	$	257,398
Contract Management	$	200,738
Nominations	$	145,641
Invoicing & Payment Processing	$	115,433
Demand Forecasting & Supply Planning	$	64,708
Direct Purchase Billing Adjustments		N/A
Total incremental costs for activities	$	783,918
Fringe benefits for labour component of incremental costs	$	354,252
TOTAL	$	1,138,169

f) The functions identified as direct purchase administration related pertain to the roles and responsibilities which were performed at that time. The grouping of the responsibilities into functions may not be directly comparable to the 2009 grouping of functions however the overall incremental cost amount is comparable. The breakdown of the existing level of incremental costs for the direct purchase administration function is as follows:

Witnesses: J. Coillier
A. Kacicnik
I. MacPherson
M. Suarez
B. Vari

	Incremental Cost Estimate for 2002	
	Direct Purchase	
Nominations	$	428,833
Direct Purchase Administation	$	301,926
Direct Purchase Contract Management	$	400,530
Statement Preparation	$	24,163
Total incremental costs for activities	$	1,155,453
Fringe benefits for labour component of incremental costs	$	404,547
TOTAL	$	1,560,000

Witnesses: J. Coillier
A. Kacicnik
I. MacPherson
M. Suarez
B. Vari

GAS MARKETER GROUP INTERROGATORY #28

INTERROGATORY

Reference: Page 51, Paragraph 178

Please confirm that actual rate changes to DPAC fees will be addressed in a future Enbridge rate case, and not in these proceedings.

RESPONSE

Yes, the Company would bring forward its proposals to develop and implement the DPAC fee based on an incremental cost approach and new fee structure in its 2010 rate adjustment application.

Witness: A. Kacicnik

GAS MARKETER GROUP INTERROGATORY #29

INTERROGATORY

Reference: Page 52, Issue 9.2

If DP customers were to be provided access to manage their own transportation and storage, could EGD costs related to load balancing decline? If not, why not?

RESPONSE

With the current level of unbundling customers can make their own arrangements for gas supply and associated transportation to Enbridge's franchise area or can do so through a gas vendor. Such arrangements are accommodated through direct purchase options. Regardless of the type of customers' supply arrangements, Enbridge provides load balancing and distribution service to all customers.

Unbundling of load balancing and storage for bundled general service (i.e. mass market) customers is outside the scope of this proceeding.

Witnesses: J. Collier
M. Giridhar
A. Kacicnik
M. Suarez

GAS MARKETER GROUP INTERROGATORY #30

INTERROGATORY

Reference: Page 56, General – Billing Terminology

Does Enbridge agree that harmonized billing terminology amongst natural gas distributors would provide customers province wide with a clearer understanding of materials presented to them from the OEB, Industry, or Media, in support of customer education?

RESPONSE

Enbridge does not agree. As submitted in the evidence, given the current level of consistency amongst natural gas distributors the degree of variance would not be noticeable for the average customer.

Witness: A. Creery

GAS MARKETER GROUP INTERROGATORY #31

INTERROGATORY

Reference: Page 56, Paragraph 195

Please explain why an ongoing mechanism to coordinate bill messaging between Enbridge and Union Gas would be required.

RESPONSE

It is Enbridge's submission that a mechanism would be required to ensure agreement between the utilities on the content of bill messages that correspond to any changes in line item descriptions.

Witness: A. Creery

GAS MARKETER GROUP INTERROGATORY #32

INTERROGATORY

Reference: Page 58, Paragraph 202

Please provide a detailed breakdown of the estimated $100, 000 to change the disposition of PGVA balances over a 12 month rolling period.

RESPONSE

Please refer to the Company's response to Board Staff Interrogatory #9 at Exhibit I24, Schedule 9.

Witnesses: I. Abbasi
A. Kacicnik

GAS MARKETER GROUP INTERROGATORY #33

INTERROGATORY

Reference: Page 59, Paragraph 208

Please provide a detailed breakdown of the estimated $1.0 to $1.5 M per year cost increase to increase the price adjustment frequency.

RESPONSE

Please refer to the Company's response to Board Staff Interrogatories #1 and #9 at Exhibit I24, Schedules 1 and 9, respectively.

Witnesses: I. Abbasi
A. Kacicnik

GAS MARKETER GROUP INTERROGATORY #34

INTERROGATORY

Reference: Page 60, Paragraph 212

Please provide estimated timelines and implementation dates for all system and operational changes alluded to in this section.

RESPONSE

The simpler proposals such as removal of the trigger mechanism and a shift to clearing of PGVA balances over a 12 month rolling period could be implemented perhaps as early as January 2010 depending on when the decision to proceed with these proposals is made.

Proposals that require enhancements to key systems (EnTRAC, CIS) such as MDV re-establishment likely would not be implemented earlier than 2011.

Also, please see the responses to Gas Marketer Group Interrogatories #21 and # 35 at Exhibit IR8, IR14, IR18, IR19, Schedules 21 and 35, respectively.

Witnesses: I. Abbasi
A. Kacicnik

GAS MARKETER GROUP INTERROGATORY #35

INTERROGATORY

Reference: Page 60, Paragraph 213-214

Please provide Enbridge's rationale as to why MDV Re-establishment could not be implemented until sometime in 2011, given that GDAR mobility and load balancing issues need to be addressed expeditiously.

RESPONSE

The Company estimates that changes such as MDV re-establishment with weather normalization would not be implemented earlier than 2011. Enhancements to EnTRAC to incorporate the above changes are comprehensive in nature and require great care in planning and execution to avoid operational disruptions and an error free implementation.

Assuming the Board approval of the MDV re-establishment process, the implementation of the project would commence no earlier than in the 4th quarter of 2009 due to preparatory work required and the limitations on internal and (available) contracted resources. Based on Enbridge's experience with technology projects such as EnTRAC, GDAR, CIS, and NGEIR, implementation of MDV re-establishment would require at least 18 months from start to completion.

Witnesses: I. Abbasi
B. Manwaring

GAS MARKETER GROUP INTERROGATORY #36

INTERROGATORY

Reference: Technical Conference

a) EGD stated that they buy all (or virtually all) of their supply on a ratable basis and then use storage to balance their requirements on their system. Why does EGD deem this to be a preferred system as opposed to attempting to shape their supply and utilize excess pipeline capacity? Please provide the EGD injection and base volume guidelines that detail the rules that EGD must follow in setting daily or monthly injection volumes and monthly and annual storage totals.
b) EGD has stated they contract for some peaking supplies. Would Enbridge consider using more "real time" (Next day, ROM) shaping to account for the reality of available transportation out of the WCSB and other basins?

RESPONSE

a) As a system operator and supplier of last resort, EGD is required to maintain firm supply, transport, and storage to meet its daily, seasonal, and peak requirements. Utilizing firm long haul transport at a 100% load factor in conjunction with market area storage provides reliability of supply in a cost effective manner. EGD presumes that the term shaping supply and using excess pipeline capacity refers to the use of long haul interruptible transport (which has a lower priority of service) on the TransCanada Mainline to match daily demand. EGD does not believe that such procurement is prudent operating practice for a distributor required to balance supply and demand on a daily basis. Further, EGD's concerns about such procurement practices are further addressed in EGD's 2009 Rate Adjustment proceeding at EB-2008-0219, Exhibit C, Tab 1, Schedule 8.

   EGD's injections depend on the following factors: daily scheduled deliveries and daily demand, discretionary purchases, injection rights under third party storage contracts, injection capabilities at Company owned Tecumseh facilities, and storage targets to meet winter space and deliverability requirements.

b) See response to part a) above. EGD's peaking contracts provide firm supplies for a reservation fee. Readily available transport out of WCSB may not be firm. Prudent operating practice and EGD's role as system operator and supplier of last resort constrain it's use of non firm supply services.

Witnesses: M. Giridhar
D. Small

GAS MARKETER GROUP INTERROGATORY #37

INTERROGATORY

Reference: Technical Conference, November 28, 2008, Page 30

a) Please provide the breakdowns for all scenarios referred to above in IR GMG/EGDI #26 (a), (d), (e), and (f) using the fully-allocated costing methodology.
b) Please provide the fully-allocated accounting study conducted several years ago by Elenchus Research

RESPONSE

a) Please see response to Board Staff Interrogatory #5 at Exhibit IR24, Schedule 5.

b) Please see the attached report filed in RP-2003-0203 at Exhibit A3, Tab 5, Schedule 4. The study from Elenchus Research estimated the cost of the system gas function based on a stand alone company.

Witnesses: J. Collier
A. Kacicnik
M. Suarez

RP-2003-0203

Report on
Stand-Alone System Supply Costs

For
Enbridge Gas Distribution
Ontario Energy Savings Income Fund
Superior Energy

Prepared by
Elenchus Research Associates
(www.era-inc.ca)
(John Todd
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Michael Stedman
Judy Kwik)

January 21, 2004

elenchus
Research Associates

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Appendix A: Detailed Breakdown of Stand-Alone Costs A-1

1 BACKGROUND

In 2001, Enbridge Consumers Gas (ECG) agreed to an independent review of the costs of managing its system gas supply as part of a Settlement Proposal to the OEB in RP-2000-0040. Bracken Consulting was hired to "ascertain the costs of managing system gas as a distinct basis and how these costs would vary from the costs allocated to system gas customers..."

In CEED's view the approach taken by the Bracken Study was too limited as it did not capture all of the activities that would be carried out if a stand-alone operator provided system gas independently from the distribution function. In contrast, ECG's position was that the Bracken Study properly identified the functions necessary to manage system gas on a stand-alone basis.

In Decision with Reasons RP-2001-0032, the Board directed the Company to file a study of system gas management costs in two formats,[1] one being the format proposed by the Company and the other being the format proposed by CEED. The Board indicated that it expected both formats to be fully costed and presented in a manner that would enable the Board to make meaningful comparisons between the two approaches.

The specific terms of reference for this study were agreed to by Enbridge Gas Distribution (EGD) and participating intervenors as part of the settlement process in the Company's 2004 rates case.[2] In the words of the settlement proposal:

> *This study will identify and quantify all of the resources used by Enbridge Gas Distribution to bill and collect from system gas customers and to provide balancing services to system gas customers, and will compare these resources to the resources that would be required by a person who provides gas supply to system gas customers on a stand-alone basis; that is, separated from the distribution service per se, in a manner similar to direct purchase gas, instead of integrated with distribution service as is now the case.*

EGD has filed evidence that quantifies the 2005 System Gas Management Costs based on its fully allocated costs (FAC) at Exhibit A3, Tab 5, Schedule 3. Elenchus Research

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[1] Decision with Reasons, RP-2001-0032, paragraph 4.6.4.
[2] The Settlement Proposal is part of the public record in the Ontario Energy Board's ("OEB") RP-2003-0048 Decision.

Associates (ERA) was retained by EGD and the Participating Marketers (Ontario Energy Savings Income Fund and Superior Energy, represented by Macleod Dixon LLP) to conduct the study of the costs of supplying system gas on a stand-alone basis.

This report quantifies "the resources that would be required by a person who provides gas supply to system gas customers on a stand-alone basis; that is, separated from the distribution service per se, in a manner similar to direct purchase gas, instead of integrated with distribution service as is now the case." This report also presents a comparison of EGD's fully allocated 2005 System Gas Management Costs to the stand-alone costs.

Section 2 of this report provides an overview of the approach used to estimate the resources required for a stand-alone supplier to serve system gas customers and a high level view of the estimated costs. The detailed description of the cost items included in the analysis, and the basis of the estimate for each cost item, is provided in section 3. Detailed summary tables of the estimated costs appear in Appendix A. Section 4 summarizes the report's conclusions.

2 Overview of the Approach and Results

The details of the operating model to be assumed for the stand-alone supplier of system gas are not set out in the Settlement Proposal. During the course of the study, it became apparent that EGD and the marketers have different views on the assumptions that should be made about the activities that should be considered in quantifying the costs of a hypothetical stand-alone supplier for purposes of the project. In the view of ERA, both views are consistent with the Terms of Reference for the project.

ERA has addressed this dilemma by developing costs estimates for all activities that are relevant to the positions of either party. The sponsors of this work disagree on whether certain of the activities should be included in deriving the total costs of the stand-alone supplier. In ERA's view, the assumptions that are appropriate to make in this regard are a matter of policy and should be determined by the Board based on the use to be made of the estimated resource costs for a hypothetical stand-alone supplier.

In order to ensure that the Board can make a direct comparison between the FAC approach and the stand-alone approach, and to make the costs of the stand-alone supplier transparent for a variety of credible operational assumptions, ERA has quantified the stand-alone costs in two ways.

- Comparable Activity Approach: This approach includes in the costing of the stand-alone supplier only those activities that are currently performed by EGD in its capacity as the supplier of gas for system customers. The activities, or functions, considered in this approach correspond to the functions that are included in EGD's 2005 System Gas Management Costs. ERA estimates that the costs for these comparable activities would be:
    - For the Gas Management function: $955,182.
    - For the Billing and Customer Care function: $19,084,701.
    - Total: $20,039,883.
- Comprehensive Activity Approach: This approach includes in the costing of the supplier all activities that are currently performed by suppliers of direct purchase gas. Although some of these activities may not be necessary for a stand-alone supplier of system gas (depending on various operational assumptions), this approach ensures that the presumption that the stand-alone supplier operates "in a manner similar to direct purchase gas" is fully addressed in the study. ERA estimates that the cost that would be incurred by a stand-alone supplier for these additional functions would be:
    - Administration of customer contracts: $735,097.
    - Other operating costs: $69,780.
    - Load balancing: $17,578,105.
    - Marketing: $6,500,000.
    - Licensing compliance: $364,100.

  In addition, the cost of Comparative Activities would increase by $512,803 due to increases in customer service activity and common costs. The total costs of the

Comprehensive Activity Approach are therefore $45,799,768, an increase of $25,759,884 compared to the Comparable Activities Approach.

The Comparable Activity Approach provides the most direct comparison between EGD's fully allocated System Gas Management Costs and the cost of performing essentially the same activities on a stand-alone basis. The Comprehensive Activity Approach provides the most complete comparison to the costs incurred by retailers based on the way in which they operate in Ontario at this time.

The ERA study team developed its estimate of the annual costs of performing these functions using a bottom-up approach. That is, staff requirements were identified for the hypothetical stand-alone supplier and the associated salaries, benefits, office space, office equipment, etc that would be necessary for the business to operate were estimated. Details of the cost components are set out in Section 3 and Appendix A.

Having developed the total costs of the stand-alone supplier using this bottom-up approach, the cost items were arranged and grouped so that sub-totals could be derived that correspond to the functions included in EGD's 2005 System Gas Management Costs (the FAC study). These results are presented in Section 4.

It should be noted that the parties do not necessarily endorse the specific methods used by ERA to quantify the resources associated with specific activities, or the resulting quantum of costs. Where more than one reasonable method was available to estimate the costs associated with an activity, ERA attempted to select an approach that reflects the mid-range between approaches that would produce high and low costs.

It is therefore ERA's view that, on balance, the costs figures set out in this report are reasonable estimates that balance factors that could increase, and decrease, the costs that would be borne by a real-world stand-alone supplier of system gas.

2.1 DISAGGREGATING SYSTEM CUSTOMER AND SYSTEM OPERATIONAL GAS

In considering the activities that would be performed by a stand-alone supplier, it is necessary to recognize that the system gas function currently performed by EGD involves more than supplying system customers with gas. It is therefore necessary to separate conceptually EGD's existing system supply function into two components:

- provision of gas to system supply customers, and
- operational load balancing for the distribution system on a daily basis (i.e., using peaking gas and daily or monthly gas requirements to maintain "system integrity").

Costs associated with the latter function would be incurred by EGD even if 100% of customers were to sign up with retailers (or be served by a combination of retailers and a stand-alone supplier) and the current terms and conditions for retailers supplying gas to EGD were unchanged. Hence, daily load balancing would continue to be the responsibility of EGD even if gas for system customers were supplied on a stand-alone basis. Furthermore, because this service is provided for both direct purchase and system supply customers, the associated costs would be allocated to rate classes and would be recovered from all customers through the EGD delivery charge.

For purposes of this study, it is therefore assumed that the stand-alone supplier delivers gas to EGD on the same basis as retailers currently deliver gas (essentially at 100% load factor). As a result, costs related to daily load balancing are excluded from the assessment of the costs attributable to the hypothetical stand-alone supplier. This approach ensures consistency with the direction contained in the terms of reference that the stand-alone supplier operates "in a manner similar to direct purchase gas".

2.2 THE COMPARABLE ACTIVITIES APPROACH

This section compares the results of EGD 2005 System Gas Management Costs to ERA's estimate of performing the comparable activities on a stand-alone basis. The details of the approach used to derive each line item contributing to the estimated cost of Comparable Activities are provided in section 5.

EGD has filed evidence in the current proceeding, in compliance with the Settlement Proposal and the Board's RP-2001-0032 Decision, that derives its 2005 System Gas Management Costs using its fully allocated costing methodology at Exhibit A3, Tab 5, Schedule 3. The evidence identifies 13 cost categories (10 functions plus three additional cost categories). For ease of comparison with the stand-alone costs, EGD's fully allocated costs are presented in Table 1, below, reorganized and sub-totalled so as to facilitate a direct comparison with the stand-alone costs derived by ERA for the comparable Gas Management and Billing & Customer Care functions.

Table 1: 2005 System Gas Management Costs (FAC Method) and Stand-alone System Supply Costs (Comparable Activities)

	Function	Integrated Cost (FAC Method)	Comparable Stand-alone Cost
1.	Gas Acquisition	548,748	
2.	Risk Management	127,863	
3.	Contract Management	322,707	
4.	Nominations	509,663	
	Subtotal – Gas Management	**1,508,981**	**955,182**
5.	Invoice Processing & Payment	72,470	
6.	Reporting	24,157	
7.	Billing	4,499,159	
8.	Credit & Collection	6,639,473	
9.	CIS Fee	633,216	
10.	Call Center	1,247,473	
11.	A&G Overhead and Benefits	100,000	
	Subtotal	**13,215,948**	
	Commodity Elements		
12.	Return on Rate Base*	1,230,000	
13.	Bad Debt Expense*	8,140,000	
	Subtotal – Customer Care	**22,585,948**	**19,084,701**
	Total System Gas Management Costs	**24,094,929**	**20,039,883**

* Return on rate base and bad debt expense are not recovered by EGD through the System Gas Fee.

Based on the ERA estimate of costs, the stand-alone costs for the Gas Management function are $554,000 (i.e., about 37%) less than EGD's fully allocated cost for the comparable functions. The stand-alone costs for the Billing and Customer Care function are $3.5 million (i.e., about 15%) less than EGD's fully allocated costs for comparable functions. It should be noted that 82% of the stand-alone Billing and Customers Care costs are accounted for by the ABC billing charge ($15.6 million of the $19.1 million total stand-alone cost). As a result, the stand-alone costs are quite sensitive to the level of the EGD's ABC billing fee.

The total stand-alone cost for Comparable Activities is $4 million, or about 17%, less than EGD's fully allocated 2005 System Gas Management Costs.

2.3 *THE COMPREHENSIVE ACTIVITIES APPROACH*

The Comprehensive Activities Approach includes in the total costs of the hypothetical stand-alone supplier several activities that are currently integral to the operations of retailers in the Ontario market that are supplying direct purchase gas to customers.

Table 2: 2005 System Gas Management Costs (FAC Method) and Stand-alone System Supply Costs (Comprehensive)

	Function	Integrated Cost (FAC Method)	Comprehensive Stand-alone Cost
1.	Gas Acquisition	548,748	
2.	Risk Management	127,863	
3.	Contract Management	322,707	
4.	Nominations	509,663	
	Subtotal – Gas Management	**1,508,981**	**983,332**
5.	Invoice Processing & Payment	72,470	
6.	Reporting	24,157	
7.	Billing	4,499,159	
8.	Credit & Collection	6,639,473	
9.	CIS Fee	633,216	
10.	Call Center	1,247,473	
11.	A&G Overhead and Benefits	100,000	
	Subtotal	**13,215,948**	
	Commodity Elements		
12.	Return on Rate Base*	1,230,000	
13.	Bad Debt Expense*	8,140,000	
	Subtotal – Customer Care	**22,585,948**	**19,569,355**
	Additional Retailer Functions		
14.	Customer Contract Admin		735,097
15.	Other Operating Costs		69,780
16.	Load Balancing		17,578,104
17.	Marketing		6,500,000
18.	OEB Licensing/Compliance		364,100
	Subtotal – Additional Functions		**25,247,081**
	Total System Gas Management Costs	**24,094,929**	**45,799,768**

* Return on rate base and bad debt expense are not recovered by EGD through the System Gas Fee.

These costs are, in the view of some parties, relevant costs to include in the determination of the "resources that would be required by a person who provides gas supply to system gas customers on a stand-alone basis; that is, separated from the distribution service per se, in a manner similar to direct purchase gas, instead of integrated with distribution service as is now the case" (emphasis added).

It should be noted that Comprehensive Stand-alone Costs differ somewhat from the Comparative Stand-alone Costs for the Gas Management and Billing & Customer Care functions. The difference relates to an increase in the estimated call centre costs resulting from the inclusion of the additional retailer functions. The associated staff additions also increase common costs. Furthermore, the increase in Customer Care costs reduces the allocation of common costs to the Gas Management function.

Based on the ERA estimate of costs, the inclusion of the additional retail functions increases the stand-alone costs from $20.0 million to $45.8 million, a 129% increase relative to the Comparable Activities Approach.

3 COST ESTIMATION METHODOLOGY

The detailed breakdown of the costs included in the estimated stand-alone system supply costs for Comparable Activities is provided in Appendix A, Table A-1. This table consists of three pages showing respectively:

- Gas management costs,
- Billing & customer care costs, and
- Common costs.

The allocation of common costs to the Gas Management and the Billing & Customer Care functions is shown at the end of the table (page A-3). Page 3 also shows the total cost for Comparable Activities.

Table A-2 in Appendix A provides the detailed breakdown of the costs included in the estimated stand-alone system supply costs for the Comprehensive Activities Approach. Table A-2 contains a fourth page detailing the additional stand-alone costs associated with activities that are currently integral to the operations of retailers in the Ontario market that are supplying direct purchase gas to customers.

This section explains the approach used for each category of stand-alone costs. Numerical references are to the line numbers appearing in the tables in Appendix A.

3.1 DATA SOURCES

The sources of information used in establishing costs for the stand-alone model include:

- Expert Opinion of the ERA Team on costs associated with performing the functions on a stand-alone basis;
- Bracken Study filed in the EGD rate case RP-2001-0032 as Exhibit A, Tab 14, Schedule 6;
- EGD information;
- Information provided by the marketers involved in the discussions on the Stand-alone System Supply model;
- Service suppliers (e.g Customer Expressions, NYMEX, etc.)

3.2 GAS MANAGEMENT (1.0.0 AND 5.0.0)

3.2.1 SALARY & BONUSES (1.1.0 AND 5.1.0)

The Gas Management salary and bonus figures rely on the Bracken Study which contains salary and bonus information derived from a Towers Perrin Market Salary Survey of Oil and Gas Marketers and Producers. These salary and bonus levels are intended to reflect competitive levels for the energy procurement skills. The bonus levels used ranges from 5% for the analyst/clerk level to 25% for the Director (General Manager in the Bracken Study) and Senior Buyer level. Table 2, Salaries, Bonuses, Benefits and Payroll Costs, of the Bracken Study is reproduced here.

Bracken Study's Table 2- Salaries, Bonuses, Benefits and Payroll Costs

	Salary & Bonus			Benefits & Payroll Costs				
	Salary	Bonus	**Sub Total**	Benefits	CPP	EI	EHT	**Sub Total**
General Manager	120,000	30,000	**150,000**	30,784	1,673	839	1,905	**35,201**
Senior Buyer	95,000	23,750	**118,750**	18,010	1,673	839	1,508	**22,030**
Contract Specialist	68,000	10,200	**78,200**	13,900	1,673	839	993	**17,405**
Costing analyst	65,000	6,500	**71,500**	13,450	1,673	839	908	**16,870**
Analyst/clerical	45,000	2,250	**47,250**	10,162	1,673	839	600	**13,274**
	$393,000	$72,700	**$465,700**	$86,306	$8,366	$4,195	$5,914	**$104,781**

The Bracken Study's General Manager's salary, bonus, benefits and payroll costs have been applied to the Gas Management Director's position and the Costing Analyst's cost levels have been applied to the Senior Gas Supply Planner's position. The Transportation/Regulatory Specialist has been assigned costs half way between those of the Senior Buyer and the Contract Specialist.

3.2.2 EMPLOYEE BENEFITS (1.2.0 AND 5.2.0)

The benefit-to-salary-plus-bonus ratio of 22.5% used for staff matches that used in the Bracken Study. The benefits assumptions used in the Bracken Study are as follows.

- Pension/retirement plan cost of 5% of salary, based on RSP matching.
- Health and dental insurance including travel coverage at an average cost of $105 per month per employee.
- Life insurance of $28 per month per employee.
- Association dues and education subsidies of $2,000 per employee.
- Staff social functions costs of $200 per employee.
- EHT is 1.27% of payroll up to $5 million.

In addition, benefit costs include stock option and car allowance for the Director.

3.2.3 OTHER OPERATING EXPENSES (1.3.0 AND 5.3.0)

Subscriptions

Costs for subscriptions includes the Gas Daily Online for four users ($7,106) as well as subscriptions identified in the Bracken Study ($2,043) to Priceline Daily, Canadian Gas Price Reporter, newspaper and magazines.

NYMEX Fees and Installation

The NYMEX user fee is $843/month for three users. The NYMEX installation charge is $2,000 and the system is assumed to be in place for 5-years. The annualized cost is based on a cost of capital of 9.6%.

Employee Expenses

The Employee Expenses presented in the Bracken Study were used to derive these costs and include the following costs per 5 employees:

Travel to Calgary	$11,288	4 trips/year unrestricted economy
Hotel - Calgary trip	$ 1,320	4 x 2 nights
Meals	$ 1,000	4 x 2 days x $125
Local Meals/Entertainment	$ 2,400	
Conferences	$ 3,000	
Other	$ 1,000	
Total	$20,008	

Based on this data, the expense figure used is $4,000/employee for five employees.

3.3 BILLING AND CUSTOMER CARE (2.0.0 AND 6.0.0)

3.3.1 SALARY AND BONUSES (2.1.0 AND 6.1.0)

The stand-alone cost estimate assumes that 4 supervisors will be required for the call centre to ensure coverage, assuming that it operates weekday evenings and on the weekend as well as during business hours. In addition, a manager would be required.

Salaries for supervisory positions were estimated using the salary scales in the Bracken Report. The Manager - Call Centre was assigned a salary of $80,000 and the bonus level used was the mid-point of the 5 to 25% bonus range presented in the Bracken Study (i.e., 15%). The four Supervisors - Call Centre were assigned salaries of $60,000 plus bonus levels at 5%.

The salaries, bonuses, benefits and payroll costs for Billing and Customer Care staff, other than the Customer Service Representatives (CSRs) are summarized in the table below. The CRS costs are captured under Customer Service cost, in section 3.3.4.

Billing and Customer Care (Call Centre) - Salaries, Bonuses and Benefits								
	Salary	Bonus	Subtotal	Benefits	CPP	EI	EHT	Subtotal
Manager	80,000	12,000	92,000	7,796	1,673	839	1168	11,476
Supervisor	60,000	3,000	63,000	6,796	1,673	839	800	10,108
Total	140,000	15,000	155,000	14,592	3,346	1678	1968	21,584

3.3.2 EMPLOYEE BENEFITS (2.2.0 AND 6.2.0)

See section 3.2.2, above.

3.3.3 CUSTOMER INFORMATION SYSTEM (2.3.0 AND 6.3.0)

The capital and maintenance costs for purchasing and maintaining a customer information system vary dramatically based on. Based on the experience of the ERA team, a reasonable range for the CIS costs for the stand-alone supplier would be $2 million to $6 million. The average cost of $4 million has been used in this study. These costs are amortized over 5 years. Ongoing support/maintenance costs were similarly established at $250,000. Hardware costs obtained from Executive Communications Limited for a business communications management system (ACD equipment) was at $37,000. In addition, $100,000 was included under hardware for systems processors. The amortization period for hardware was also set at 5 years.

3.3.4 OTHER OPERATING EXPENSES (2.4.0 AND 6.4.0)

ABC (Agent Billing Collection) Cost

This cost was calculated based the ABC rates that EGD charges per bill to marketers. A weighted average cost was calculated based on the customer forecast data (by rate class) EGD expects to file for the 2005 Fiscal Year Budget for system customers multiplied by the appropriate ABC charge. The customer numbers are somewhat higher than historical experience based on the high level of customers that returned to system this past year.

Customer Service Costs

The direct cost of Customer Service Representatives (CSRs) is reflected in this line item (2.4.2 and 6.4.2). It represents the labour cost involved in outbound and inbound telephone calls with customers. The number of CSRs required was based on the average call volumes, average handle time, customer service representative costs, etc. reported by the marketers. Full details of salary levels, etc. are not included in this report as this information was provided on a confidential basis by the marketers.

It is estimated the stand-alone supplier's call centre would require about 20 call positions (34 staff) to deal effectively with the estimated call volumes under the Comparable Activities approach. An additional five positions (8 staff) would be required under the Comprehensive Activities approach. Customer service representatives could be a combination of part-time and full-time employees. The normal business practice is to schedule employees based on expected call traffic.

Office space and office expenses are based on the estimated number of positions.

Employee Expenses – Call Centre

Training and other expenses of $800 per call centre customer service representative are assumed.

Employee Expenses - Other

The Employee Expenses presented in the Bracken Study were used to derive a cost of $4,000 per employee (see Section 3.2.3). This cost per employee was applied to all non-CSR staff.

3.4 COMMON COSTS (3.0.0 AND 7.0.0)

3.4.1 LEASE PAYMENT (3.1.0 AND 7.1.0)

The office lease costs are based on locating the office in the area between the Toronto Pearson Airport and the Enbridge Consumers Gas head office location in North York. The location is ideal for meetings, which would be required between the stand-alone supplier and EGD. Further, close proximity to the Airport is practical for business travel to Calgary where many of the gas supply companies are located.

A survey of lease prices suggests that an average lease payment plus average TMI cost is approximately $17.00 per square foot in North York.

The office space requirement is consistent with the Bracken Study space requirement with the addition of workstations for Call Centre Representatives. The lease cost for the Comparative Activities approach was derived as follows:

Office space per staff 10' x 12'	12 offices	1,440 sq. ft.
Call Centre Workstation 10 x 8'	20 workstations	1,600 sq. ft.
Meeting Room areas 15' x 15'	2 meeting rooms	450 sq. ft.
Reception and Hallways 775	2 X Bracken Study	1,550 sq. ft.
	Total Space	5,040 sq. ft.
	@ $17.00/sq.ft.	$85,680

For the Comprehensive Activities approach, an additional 15 offices would be required for 12 staff handling Customer Contract Administration (se section 3.5.1) and the three managing Marketing (see section 3.5.5). In addition, 5 additional workstations would be required in the Call Centre. Lease payment costs would therefore be:

Office space per staff 10' x 12'	27 offices	3,240 sq. ft.
Call Centre Workstation 10 x 8'	25 workstations	2,000 sq. ft.
Meeting Room areas 15' x 15'	2 meeting rooms	450 sq. ft.
Reception and Hallways 775	2 X Bracken Study	1,550 sq. ft.
	Total Space	7,240 sq. ft.
	@ $17.00/sq.ft.	$123,080

3.4.2 FURNITURE AND OFFICE EQUIPMENT (3.2.0 AND 7.2.0)

Desktop Computers

Costs used in the Bracken Study were used to derive Desktop Computer costs in this study. In the Bracken Study the total cost is estimated at $20,250 for 5 employees, with a useful life of 3 years. The cost per employee for Desktop Computers used in this study therefore is $4,050 for three years. For the Call Centre, the number of computers was based on the number of workstations, not employees.

Computer Support

The cost of computer support is based on ERA's annual Computer Support cost per computer of $766.

Furniture

The following backup data to the Bracken Study on Furniture Cost was used to derive the cost of Furniture for the stand-alone supplier.

Workstation	$ 2,700
Chairs	$ 1,512
Desk Lamps	$ 205
Waste Basket	$ 130
Meeting Table	$ 540
Meeting Chairs	$ 1,115
Guest Chairs	$ 1,672
Book Cases	$ 578
Filing Cabinets	$ 1,701
Speaker Phones	$ 756
Total	$10,908

The useful life used in the Bracken Study and applied to the costs is 5 years.

Other Office Equipment

The Bracken Study's costs for Other Office Equipment were used to derive the costs for this study. These costs cover printer, photocopying and fax equipment.

Printer	$ 2,221
Photocopier/Fax/Printer	$ 4,639
Total	$ 6,859

Since the Bracken Study's costs are for 5 employees a cost per employee of $1,372 was used assuming similar usage of the equipment in this category per employee/ workstation. A useful life of 3 years is used.

3.4.3 MISCELLANEOUS (3.3.0 AND 7.3.0)

In this cost category, where expenses are incurred for each employee, the cost is calculated based on the total number of employees, including CSRs. Hence, for costs driven by total staff, as opposed to offices/workstations, the number of units is 46 for the Comparable Activities Approach and 69 for the Comprehensive Activities Approach.

Office Cleaning

The Office Cleaning cost of $6,500 for 1,600 square feet of office space used in the Bracken Study is the basis for the $4.06/sq.ft cleaning cost used. The cost is applied to the total rental space in each Approach.

Office Supplies

The Bracken Study's cost of $3,600 for Office Supplies for 5 employees, is the basis for the $720 per employee cost used in this study. This cost is applied to the total number of employees.

Internet

The Internet service cost is based on Bell Internet High Speed Service[3] which provides high-speed modem rental, five e-mail addresses, high-speed Internet access and 20 hours free remote dial-up access for $89.95 per month for a one-year contract. This cost is applied to the number of computers.

Telephone

The Telephone service cost is based on Bell's business line bundled service[4] at $46.45 per month per line. This cost is applied to the number of non-CSR staff plus workstations.

Cell Phone

The Cell Phone costs are based on a Rogers ATT[5] business plan that includes a cell phone at $49.99 and service for $40/month that provides 350 weekday minutes with

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[3] http://www.bell.ca/shop/application/commercewf?origin=*.jsp&event=link(goto)&content=/jsp/content/business/internet/highspeed/alacarte.jsp
[4] http://www.bell.ca/shop/application/commercewf?origin=*.jsp&event=link(goto)&content=/jsp/content/business/voice/localaccess/indbuzline/pricing.jsp
[5] http://www.shoprogers.com/business/wireless/gbm/plans/overview.asp?shopperID=47NDBR8N4TA59HD3JKJCG7EJ2CKB92C1

unlimited evening and weekend use for a 24-month service agreement. All staff except call centre staff were allotted cell phones.

Postage and Courier

Based on the Bracken Study's Postage and Courier costs of $1,200 for 5 employees, this study uses $240/employee for Postage and Courier service assuming activities carried out by each employee requires, on average, this level of Postage and Courier services. This cost is applied to the total number of employees.

Legal Services

The cost of legal services is based on Jim Bracken's assumption in his backup data of 1 day per month to review contracts at $2,800 per day.

General Insurance

The General Insurance for SAS is based on ERA's general insurance cost of $800 for a 3,000 sq. ft. office for 14 employees. Four-times this rate was used as the General Insurance cost for the stand-alone supplier's office.

Human Resources and Payroll Services

The Human Resources and Payroll Services cost is based on ERA's cost per employee of $108/employee (Ceridian payroll service). This cost is applied to the total number of employees.

Consulting Fees

$15,000/year Consulting Fees are included to cover studies such as gas supply outlook and risk management reviews.

3.4.4 WORKING CAPITAL ALLOWANCE (3.5.0 AND 7.5.0)

Working capital requirement was derived by applying the OEB's working capital allowance in rate base for electricity distribution utilities described in the Electricity

Distribution Rate Handbook. The working capital allowed is 15 per cent of the sum of the cost of power and the electricity distribution utility's controllable expenses, which covers approximately 2-months of the supply cost and 1½ month of controllable expenses. Discussions with the marketers indicated that the billing lag (differential between revenue receipt and payment to the suppliers) is negligible. Therefore, for the stand-alone supplier, 1 ½ months of its costs are used as its working capital requirement. Using the OEB's allowed working capital allowance as a proxy, the cost included for stand-alone suppliers working capital is 12.5% of the annual cost subtotal in the Stand-alone System Supply Costs Table. To obtain the working capital allowance EGD's rate of return of 9.6% for 2004 was used.

3.4.5 ALLOCATION OF COMMON COSTS (3.7.0 AND 7.7.0)

Common costs were allocated to the Gas Management and Billing & Customer Care functions on the basis of the Salary and Bonus of each function. The Salary and Bonuses Subtotal for the Gas Management ($599,250 under the Comparable Activities approach) was used for that function. For the Billing and Customer Care function, the manager and supervisor salaries were added to the cost of customer service reps. (i.e., $1,556,200 in the Comparable Activities approach).

3.5 ADDITIONAL STAND-ALONE COSTS (8.0.0)

3.5.1 SALARY AND BONUSES (8.1.0)

There is considerable administration involved in initiating and maintaining direct purchase contracts and tracking the associated dollars, gas volumes and customer adds and deletions that are involved. There are also several different contracts involved in every Direct Purchase Agreement. The work involves significant manual input for both the marketer and for EGD and as a result tends to be error prone. Enbridge is implementing the Entrac system to help facilitate some of the administration involved. This system has some added flexibility but there will continue to be significant ongoing administration required by the marketers. A reasonable cost proxy for this item appears to be to base it on the number of employees in the EGD Contract Management Group as they administer all of the direct purchase contracts and deal with most direct purchase administration issues. Provision has been made for one of the positions to be a senior contract administrator given the size of the group.

The Manager-Contract Administration was assigned a salary of $80,000 and the bonus level used was the mid-point of the 5 to 25% bonus range presented in the Bracken Study, of 15%. The Senior Contract Administrator was assigned $55,000 plus a 5% bonus, and the 10 Contract Administrators were assigned salaries of $45,000 plus 5% bonuses.

Contract Administration - Salaries, Bonuses and Benefits

	Salary	Bonus	Subtotal	Benefits	CPP	EI	EHT	Subtotal
Manager	80,000	12,000	92,000	7,796	1,673	839	1168	11,476
Senior Administrator	55,000	2,750	57,750	6,546	1,673	839	733	9,791
Administrator	45,000	2,250	47,250	6,046	1,673	839	600	9,158

3.5.2 Employee Benefits (8.1.0)

See section 3.2.2.

3.5.3 Other Operating Costs (8.2.0)

Direct Purchase Administration Charge

This fee would be paid to EGD by a stand-alone supplier, operating like a supplier of direct purchase gas, each Direct Purchase Agreement (DPA). For costing purposes 12 agreements (one for each month) have been assumed. The cost per DPA is $815.

3.5.4 Load Balancing (8.3.0)

Operationally How a Marketer May Manage Year-end Load Balancing

As discussed in Section 2.1, a stand-alone supplier operating in a manner similar to existing marketers would not be responsible for daily load balancing. Daily load balancing would continue to be the responsibility of EGD as the system operator. Like marketers, the stand-alone supplier would be required to meet EGD's daily obligated deliveries and the year-end load balancing requirement. The obligation for year-end load balancing is determined by the difference between the actual consumption and the total annual gas nominated at the end of the contract year. The difference must either be removed from the system or brought into the system to balance within 180 days following the end of the contract. EGD's policy on year-end load balancing limits the balancing to plus or minus 5% of the contracts annual gas requirement.

The stand-alone supplier, like existing marketers, would have to recover the costs associated with year-end load balancing in the price of the commodity that it supplies its customers. A marketer could lock in the risk (Load Balancing cost) immediately or it could decide to manage the risk operationally throughout the term of the contract. In practice, a marketer would be likely to wait 6-8 months into the contract to assess the imbalance between gas delivered to EGD and the gas consumed by its customers and then assess how to manage the risk at least cost. There are many different ways in which a marketer may operationally manage this risk.

For example, a marketer could manage any imbalances physically. If it discovered that the position was long gas, it would either seek to sell gas off the EGD system when the Utility allowed suspensions/diversions prior to the end of the contract or wait until the end of the contract and sell the gas. If a marketer was short gas it would attempt to bring gas into the EGD system prior to the end of the contract or bring in the shortfall after the end of the contract.

An alternate approach would be to manage the risk financially through an option, then exercise the Put or Call Option after the end of the contract. The marketer may wait 6-8 months into a contract to identify a short or long position and then purchase a Call or Put option for the end of the contract.

There are other practical approaches through which a marketer can manage the Load Balancing requirements. For purposes of this study, however, it is necessary to assume an approach to load balancing that quantify in a reasonably straightforward manner the cost of year-end load balancing. In ERA's view, the best way to derive a year-end load balancing cost for purposes of this study is to assume the cost is incurred at the beginning of the contract year by way of purchasing options. This approach creates a transparent cost for a specified level of risk protection. For purposes of the study, it is assumed that options that protect against variances of up to 5% of the expected volumes. The cost is scalable, however, in that the cost can be increased or decreased proportionately to determine the cost of purchasing options to protect against greater or lesser variances.

The intention is to use the cost of the options as a proxy for the cost of all volumetric risks and therefore to eliminate any speculation related to volumetric variances and price variances due to market changes. By assuming that risk is addressed at any time after the commencement of the contract year, there would be a risk that the volume forecast or market prices could change; hence, risk could not be mitigated fully.

Call and Put Options

An option in the natural gas business is the right but not the obligation to buy gas (Call Option) or sell gas (Put Option) at a specific price for a specific time. At the end of the contract term the supplier would have the ability to exercise the option to manage its long or short position. The term "exercise" is used to describe the purchaser ability to demand the seller of the Call Option or Put Option to purchase or deliver natural gas at the exercise price. The option only has value for a defined period of time after which the underlying option will not be exercisable. The option premium is a value that will change over time based on volatility in the marketplace.

Assumption Used for an Initial Quote

The following assumptions were used in obtaining quotes:

- The term of the contract is one year. For the quotes below the contract start is December 1, 2003.
- A Put Option and a Call Option is secured at the start of the contract.
- 5% imbalance requirements are managed after the end of the contract. Assume the imbalance information is not validated until two months after the end of the contract.

- Exercise the Put or Call evenly over the third month at Dawn. In this case January 2005.
- The option is secured "at the money" for the month of January 2005. "At the Money" in the energy business is defined as an option where the strike price is the same as the current market price of the natural gas commodity. In this case the future price of the commodity today for the month of January 2005 is the same as the price one would pay or sell the commodity in January 2005.

The costs for a Call Option and a Put Option are quotes on November 20, 2003. A US exchange rate of 0.7674 and heat rate conversion of 37.69 $GJ/103m^3$ were used. A range of call and put option costs were then derived as follows:

Price of Commodity =	$5.050	US/MMBTU					
	$6.240	CND/GJ					
	$0.235	CND/M3					
			Range				
Quote: Call & Put	$1.020	US/MMBTU		$1.120	US/MMBTU		
	$1.260	CND/GJ	to	$1.384	CND/GJ		
	$0.048	CND/M3		$0.052	CND/M3		
Assume customer use at		**3,064**	M3/yr				
Assume number of customers		**1,151,302**					
Amount of Protection Required		**5**	%				
						Mid-Point	
Cost for Call Option =	$8,378,349	to	$9,199,756			**$ 8,789,052**	
Cost for Put Option =	$8,378,349	to	$9,199,756			**$ 8,789,052**	
Total Cost Option =	**$16,756,698**	**/yr**	**$18,399,511**	**/yr**		**$17,578,105**	**/yr**

The quote above is one quote for one contract starting December 1, 2003. The ideal method to assess the costs of Load Balancing is to repeat this quote over a twelve month period for contracts starting each month of the year. The volume used for each month would be the volumes in each contract. In the example above the volume would be reduced to reflect only the volume in the December contract.

For this study the mid-point of the call and put option ranges in the example above were used as the load balancing cost.

3.5.5 MARKETING COSTS (8.4.0)

Marketers in Ontario traditionally incur costs to acquire customers from door to door sales or through acquisition of another marketer's contracts. The hypothetical stand-alone supplier operating "in a manner similar to [a supplier of] direct purchase gas" can therefore be deemed to incur costs that are comparable to the costs that would be incurred by a marketer. The marketing cost figure attributable to the stand-alone supplier can be determined by multiplying the number of customers by the marketing cost per customer.

Cost per Customer

The acquisition costs incurred by Ontario marketers are, in many instances, a matter of public record. These acquisition costs have varied considerable, however, reflecting significant differences in the assets being acquired and the value of the specific assets being acquired.[6] As a result, reported acquisition costs do not provide a clear valuation of the customer contracts as distinct from other assets such as gas supply, storage and transportation contracts.

As a result, the marketing cost per customer used in this study was derived based on publicly available annual reports that include marketing cost details. A review of this information indicates that an average cost of $130 per new customer is reasonable.[7]

Number of Customers

The annual marketing cost for the stand-alone supplier that would be comparable to other marketers would be based on EGD's average annual customers growth (i.e. 50,000 customers).

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[6] For example, Energy Savings Income Trust carries an amortised annual amount approximately $47 million in its financial statements, with recent acquisition in Ontario having values ranging from about $70 to $235 per RCE (residential contract equivalent). This range driven by the underlying value of not only the customers acquired, but also gas supply contracts that may be "in or out of the money" and possibly other assets.

[7] Energy Savings Income Trust's financial reports were relied on as they provided the most accessible information.

Potentially, an initial start-up cost for the stand-alone supplier could be calculated reflecting an acquisition of the initial base of system customers. This figure has not been included for in ERA's estimate of the costs of the hypothetical stand-alone supplier. It is not clear whether the marketing cost derived above (i.e., $130) would be an appropriate basis for valuing customers transferred to the stand-alone marketer, nor how that hypothetical acquisition cost should be treated for purposes of the valuation of the costs of a stand-alone supplier of system gas. It should be noted, nevertheless, that from a financial accounting perspective such costs could be recognized and amortised over the expected life of the supplier's relationship with the average system gas customer.

Other Marketing-Related Costs

Marketing (related to end use customer marketing) would also require a manager. In addition, a marketing (research) analyst and marketing co-ordinator at a minimum would be required. The marketing salaries have not been included as these costs are captured in the marketing cost calculation above. However, three positions are assumed for purposes of determining incremental Common Costs for the Comprehensive Activities Approach, relative to the Comparable Activities Approach (i.e., for office space and other office requirements and costs).

3.5.6 OEB LICENSING AND COMPLIANCE COSTS (8.5.0)

The main cost items that are not covered as part of marketing costs (i.e. reaffirmation costs) are the cost for the complaint resolution process and renewal requirement costs. The complaint resolution costs are paid by marketers to Customer Expressions in Ottawa to help pay for the process. Cost is based primarily on each marketer's "track record" of calls. This cost has been calculated based on an average of 500 calls per month ($35 on average to resolve) plus a flat fee of $100 per month. This information was obtained from the service provider. Calls tend to be much higher during marketing campaigns but then drop dramatically after they are completed. The information provided was considered an appropriate average for to use for this cost study.

The renewal requirements for customer supply contracts currently involve sending a letter to customers in advance of their contract renewal date to inform them of their options and the contract rate going forward. Follow-up calls may result but these are included in the Customer Service costs. For the Stand-alone Supplier, an average contract length of 4 years was assumed because large marketers focus on selling 3 and 5-year contracts. Accordingly, about 275,000 letters would be produced and mailed over the course of a year. The main cost element is postage. The bulk rate for postage is currently 36 cents per letter.

This mailing could be outsourced for about $152,400 annually. Almost two-thirds of the costs are for postage ($99,000). Paper, envelopes, data and mail processing would cost an additional $53,400 annually.

A few additional compliance items were identified. Affirmation calls to customers are included in the customer service costing and are not reflected here. The cost of fraud investigations was considered minor and not predictable. Hence no cost has been included for this item.

4 SUMMARY OF CONCLUSIONS

Table 3 summarizes the high level comparison of EGD's 2005 fully allocated System Gas Management Costs to the estimates costs of a stand-alone supplier of system gas using both the costs Comparable Activities and Comprehensive Approaches.

Table 3: Summary of System Gas Management Costs

	Function	Integrated Cost (FAC Method)	Comparable Approach	Comprehensive Approach
	Gas Management	**1,508,981**	**955,182**	**983,332**
	Customer Care	**22,585,948**	**19,084,701**	**19,569,355**
	Additional Retailer Costs			**25,247,081**
	Total System Gas Costs	**24,094,929**	**20,039,883**	**45,799,768**

Appendix A: Detailed Breakdown of Stand-Alone Costs

Table A-1: Stand-alone System Supply Costs - Comparable Activities Approach

	Cost Component	Annualized Cost	Useful Life	Total Cost	Number of units	Cost per unit	Data Source
1.0.0	**GAS MANAGEMENT**						
1.1.0	**Salary & Bonuses**						
1.1.1	Director	150,000	1	150,000	1	150,000	Bracken Study
1.1.2	Senior Buyer	118,750	1	118,750	1	118,750	Bracken Study
1.1.3	Contract Specialist	78,200	1	78,200	1	78,200	Bracken Study
1.1.4	Analyst/Clerical Support	47,250	1	47,250	1	47,250	Bracken Study
1.1.5	Senior Costing Analyst	35,750	1	35,750	0.5	71,500	Bracken Study
1.1.6	Senior Gas Supply Planner	71,500	1	71,500	1	71,500	ERA
1.1.7	Transporation/Regulatory Specialist	97,800	1	97,800	1	97,800	ERA
1.1.8	**Subtotal**	**599,250**					
1.2.0	**Employee Benefits**						
1.2.1	Director	35,201	1	35,201	1	35,201	Bracken Study
1.2.2	Senior Buyer	22,030	1	22,030	1	22,030	Bracken Study
1.2.3	Contract Specialist	17,405	1	17,405	1	17,405	Bracken Study
1.2.4	Analyst/Clerical Support	10,631	1	10,631	1	10,631	Bracken Study
1.2.5	Senior Costing Analyst				0.5	16,870	Bracken Study
1.2.6	Senior Gas Supply Planner	16,870	1	16,870	1	16,870	ERA
1.2.7	Transporation/Regulatory Specialist	19,718	1	19,718	1	19,718	ERA
1.2.8	**Subtotal**	121,855					
1.3.0	**Other Operating Expenses**						
1.3.1	Subscriptions	9,149	1	9,149	1	9,149	Bracken Study
1.3.2	NYMEX -User Fee	10,008	1	10,008	12	834	ERA
1.3.3	NYMEX Installation	522	5	2,000			NYMEX, ERA
1.3.4	Employee Expenses	28,000	1	28,000	7	4,000	Bracken Study
1.4.0	**Subtotal: Gas Management**	**768,784**					
1.5.0	**Allocation of Common Costs**	**186,397**					
1.6.0	**Total: Gas Management**	**955,182**					

Table A-1: Stand-alone System Supply Costs - Comparable Activities Approach

	Cost Component	Annualized Cost	Useful Life	Total Cost	Number of units	Cost per unit	Data Source
2.0.0	**BILLING AND CUSTOMER CARE**						
2.1.0	**Salary & Bonuses**						
2.1.1	Manager - Call Centre	92,000	1	92,000	1	92,000	Marketers, ERA
2.1.2	Supervisors - Call Centre	252,000	1	252,000	4	63,000	Marketers, ERA
2.2.0	**Employee Benefits**						
2.2.1	Manager - Call Centre	11,476	1	11,476	1	11,476	Marketers, ERA
2.2.2	Supervisors - Call Centre,	40,432	1	40,432	4	10,108	Marketers, ERA
2.3.0	**Customer Information System**						
2.3.1	a. Capital/purchase costs	1,044,429	5	4,000,000	1	4,000,000	Marketers input, ERA
2.3.2	b. Average maintanence costs	250,000	1	250,000	1	250,000	Marketers input, ERA
2.3.3	c. Hardware requirements	35,772	5	137,000	1	137,000	
2.4.0	**Other Operating Expenses**						
2.4.1	ABC billing charge from EGD	15,608,735	1	15,608,735	1,151,302	13.56	EGD ABC fee
2.4.2	Customer Service(CS) Costs	1,212,200	1	1,212,200			Marketers, ERA
2.4.3	Employee Expenses-Call Centre	33,600	1	33,600	42	800	ERA
2.4.4	Employe Expenses - Other	20,000	1	20,000	5	4,000	Bracken Study
2.5.0	**Subtotal: Billing & Customer Care**	**18,600,644**					
2.6.0	**Allocation of Common Costs**	**484,058**					
2.7.0	**Total: Billing & Customer Care**	**19,084,701**					

Table A-1: Stand-alone System Supply Costs - Comparable Activities Approach

	Cost Component	Annualized Cost	Useful Life	Total Cost	Number of units	Cost per unit	Data Source
3.0.0	**COMMON COSTS**						
3.1.0	**Lease Payment**	85,680	1	85,680	5,040	17	ERA Survey
3.2.0	**Furniture and Office Equipment**						
3.2.1	Desktop computers	51,747	3	129,600	32	4,050	Bracken Study
3.2.2	Computer Support	24,512	1	24,512	32	766	ERA's cost
3.2.3	Furniture	91,141	5	349,056	32	10,908	Bracken Study
3.2.4	Other Office Equipment	17,528	3	43,898	32	1,372	Bracken Study
3.3.0	**Miscellaneous**						
3.3.1	Office Cleaning	26,309	1	26,309	6,480	4.06	Bracken Study
3.3.2	Office Supplies	33,120	1	33,120	46	720	Bracken Study
3.3.3	Internet	6,912	1	6,912	32	216	Bell Internet Service
3.3.4	Telephone	17,837	1	17,837	32	557	Bell Bundled Service
3.3.5	Long Distance	2,304	1	2,304	28,800	0.08	Bell Long Distance,
3.3.6	Cell Phones	6,060	2	12,120	12	1,010	ATT Wireless Service.
3.3.7	Postage and Courier	11,040	1	11,040	46	240	Bracken Study
3.3.8	Legal Services	33,600	1				Bracken Study
3.3.9	Memberships/donations	1,070	1				OEA Membership
3.3.10	General Insurance	4,000	1	4,000		57	Based on ERA's cost
3.3.11	Human resources and payroll services	4,968	1	4,968	46	108	Based on ERA's cost
3.3.12	Consulting Fees	15,000	1				ERA
3.4.0	**Subtotal: Common Costs**	**432,828**					
3.5.0	**Working Capital Allowance**	**237,627**					12.5 % of expenses
3.6.0	**Total: Common Costs**	**670,455**					
3.7.0	**Allocation of Common Costs**						
3.7.1	Gas Management	**186,397**					
3.7.2	Billing & Customer Care	**484,058**					
4.0.0	**TOTAL: COMPARABLE COST**	**20,039,883**					

Table A-2: Stand-alone System Supply Costs - Comprehensive Activities Approach

	Cost Component	Annualized Cost	Cost Differential	Useful Life	Total Cost	Number of units	Cost per unit	Data Source
5.0.0	**GAS MANAGEMENT**							
5.1.0	**Salary & Bonuses**							
5.1.1	Director	150,000	-	1	150,000	1	150,000	Bracken Study
5.1.2	Senior Buyer	118,750	-	1	118,750	1	118,750	Bracken Study
5.1.3	Contract Specialist	78,200	-	1	78,200	1	78,200	Bracken Study
5.1.4	Analyst/Clerical Support	47,250	-	1	47,250	1	47,250	Bracken Study
5.1.5	Senior Costing Analyst	35,750	-	1	35,750	0.5	71,500	Bracken Study
5.1.6	Senior Gas Supply Planner	71,500	-	1	71,500	1	71,500	ERA
5.1.7	Transporation/Regulatory Specialist	97,800	-	1	97,800	1	97,800	ERA
5.1.8	**Subtotal**	**599,250**						
5.2.0	**Employee Benefits**							
5.2.1	Director	35,201	-	1	35,201	1	35,201	Bracken Study
5.2.2	Senior Buyer	22,030	-	1	22,030	1	22,030	Bracken Study
5.2.3	Contract Specialist	17,405	-	1	17,405	1	17,405	Bracken Study
5.2.4	Analyst/Clerical Support	10,631	-	1	10,631	1	10,631	Bracken Study
5.2.5	Senior Costing Analyst					0.5	16,870	Bracken Study
5.2.6	Senior Gas Supply Planner	16,870	-	1	16,870	1	16,870	ERA
5.2.7	Transporation/Regulatory Specialist	19,718	-	1	19,718	1	19,718	ERA
5.2.8	**Subtotal**	121,855						
5.3.0	**Other Operating Expenses**							
5.3.1	Subscriptions	9,149	-	1	9,149	1	9,149	Bracken Study
5.3.2	NYMEX -User Fee	10,008	-	1	10,008	12	834	ERA
5.3.3	NYMEX Installation	522	-	5	2,000			NYMEX, ERA
5.3.4	Employee Expenses	28,000	-	1	28,000	7	4,000	Bracken Study
5.4.0	**Subtotal: Gas Management**	**768,784**	-					
5.5.0	**Allocation of Common Costs**	**214,547**	28,150					
5.6.0	**Total: Gas Management**	**983,332**	28,150					

Table A-2: Stand-alone System Supply Costs - Comprehensive Activities Approach

	Cost Component	Annualized Cost	Cost Differential	Useful Life	Total Cost	Number of units	Cost per unit	Data Source
6.0.0	**BILLING AND CUSTOMER CARE**							
6.1.0	**Salary & Bonuses**							
6.1.1	Manager - Call Centre	92,000	-	1	92,000	1	92,000	Marketers, ERA
6.1.2	Supervisors - Call Centre	252,000	-	1	252,000	4	63,000	Marketers, ERA
6.2.0	**Employee Benefits**							
6.2.1	Manager - Call Centre	11,476	-	1	11,476	1	11,476	Marketers, ERA
6.2.2	Supervisors - Call Centre,	40,432	-	1	40,432	4	10,108	Marketers, ERA
6.3.0	**Customer Information System:**							
6.3.1	a. Capital/purchase costs	1,044,429	-	5	4,000,000	1	4,000,000	Marketers input, ERA
6.3.2	b. Average maintanence costs	250,000	-	1	250,000	1	250,000	Marketers input, ERA
6.3.3	c. Hardware requirements	35,772	-	5	137,000	1	137,000	
6.4.0	**Other Operating Expenses**							
6.4.1	ABC billing charge from EGD	15,608,735	-	1	15,608,735	1,151,302	13.56	EGD ABC fee
6.4.2	Customer Service(CS) Costs	1,515,250	303,050	1	1,515,250		1.25	Marketers, ERA
6.4.3	Employee Expenses-Call Centre	33,600	-	1	33,600	42	800	ERA
6.4.4	Employe Expenses - Other	20,000	-	1	20,000	5	4,000	Bracken Study
6.5.0	**Subtotal: Billing & Customer Care**	**18,903,694**	303,050					
6.6.0	**Allocation of Common Costs**	**665,661**	181,603					
6.7.0	**Total: Billing & Customer Care**	**19,569,355**	484,653					

Table A-2: Stand-alone System Supply Costs - Comprehensive Activities Approach

	Cost Component	Annualized Cost	Cost Differential	Useful Life	Total Cost	Number of units	Cost per unit	Data Source
7.0.0	**COMMON COSTS**							
7.1.0	**Lease Payment**	123,080	37,400	1	123,080	7,240	17	ERA Survey
7.2.0	**Furniture and Office Equipment**							
7.2.1	Desktop computers	84,090	32,342	3	210,600	52	4,050	Bracken Study
7.2.2	Computer Support	39,832	15,320	1	39,832	52	766	ERA's cost
7.2.3	Furniture	148,104	56,963	5	567,216	52	10,908	Bracken Study
7.2.4	Other Office Equipment	28,483	10,955	3	71,334	52	1,372	Bracken Study
7.3.0	**Miscellaneous**							
7.3.1	Office Cleaning	29,394	3,086	1	29,394	7,240	4.06	Bracken Study
7.3.2	Office Supplies	49,680	16,560	1	49,680	69	720	Bracken Study
7.3.3	Internet	11,232	4,320	1	11,232	52	216	Bell Internet Service
7.3.4	Telephone	28,985	11,148	1	28,985	52	557	Bell Bundled Service
7.3.5	Long Distance	2,304	-	1	2,304	28,800	0.08	Bell Long Distance,
7.3.6	Cell Phones	13,635	7,575	2	27,270	27	1,010	ATT Wireless Service.
7.3.7	Postage and Courier	16,560	5,520	1	16,560	69	240	Bracken Study
7.3.8	Legal Services	33,600	-	1				Bracken Study
7.3.9	Memberships/donations	1,070	-	1				OEA Membership
7.3.10	General Insurance	4,000	-	1	4,000		57	Based on ERA's cost
7.3.11	Human resources and payroll services	7,452	2,484	1	7,452	69	108	Based on ERA's cost
7.3.12	Consulting Fees	15,000	-	1				ERA
7.4.0	**Subtotal: Common Costs**	**636,501**	203,673					
7.5.0	**Working Capital Allowance**	**243,708**	6,081					12.5 % of expenses
7.6.0	**Total: Common Costs**	**880,208**	209,753					
7.7.0	**Allocation of Common Costs**							
7.7.1	Gas Management	**214,547**	28,150					
7.7.2	Billing & Customer Care	**665,661**	181,603					

Table A-2: Stand-alone System Supply Costs - Comprehensive Activities Approach

	Cost Component	Annualized Cost	Cost Differential	Useful Life	Total Cost	Number of units	Cost per unit	Data Source
8.0.0	**ADDITIONAL RETAILER COSTS**							
8.1.0	**Customer Contract Admin.**							
	Salaries							
8.1.1	Manager, Contract Administration	92,000	92,000	1	92,000	1	92,000	Marketers, ERA
8.1.2	Senior Contract Administrator	57,750	57,750	1	57,750	1	57,750	ERA
8.1.3	Contract Administrator	472,500	472,500	1	472,500	10	47,250	EGD
	Benefits							
8.1.4	Manager, Contract Admin	11,476	11,476	1	11,476	1	11,476	Marketers, ERA
8.1.5	Senior Contract Adminstrator	9,791	9,791	1	9,791	1	9,791	ERA
8.1.6	Contract Administrator	91,580	91,580	1	91,580	10	9,158	ERA
8.1.7	**Subtotal: Contract Admin**	**735,097**	**735,097**					
8.2.0	**Other Operating Costs**							
8.2.1	Direct Purchase Admin charge	9,780	9,780	1	9,780	12	815	EGD DPAC fee
8.2.1	Employee Expenses	60,000	60,000	1	60,000	15	4,000	Bracken Study
8.3.0	**Load Balancing**							
8.3.1	Call Option	8,789,052	8,789,052	1	8,789,052	3,100m^3	1,151,302	Quote for 20/11/03
8.3.2	Put Option	8,789,052	8,789,052	1	8,789,052	3,100m^3	1,151,302	Quote for 20/11/03
8.4.0	**Marketing Costs**	6,500,000	6,500,000	1	6,500,000	50,000	130	Cost/customer based on
8.5.0	**OEB Licensing/Compliance Costs**							
8.5.1	a. licence cost	500	500	One	500	1	500	OEB
8.5.2	b. reaffirm contracts							Marketers
8.5.3	c. fraud reporting and investigation							
8.5.4	d. complaint resolution costs	210,000	210,000	1	210,000	6,000	35	Customer Expression
8.5.5		1,200	1,200	1	1,200	12	100	Customer Expression
8.5.6	e. renewal requirements cost	152,400	152,400	1	152,400			Mediamix
8.5.7	f. GDAR requirements							
8.5.8	**Subtotal: License Compliance**	**364,100**	**364,100**					
8.6.0	**Total Additional Costs**	**25,247,081**	**25,247,081**					
9.0.0	**TOTAL: COMPREHENSIVE COST**	**45,799,768**	**25,759,884**					

EGDI - FRPO IR10

FRPO INTERROGATORY #1

INTERROGATORY

Ref: Exhibit E1, page 31, para. 99 "In calculating the delivery requirement for General Service customers (Rates 1and 6), Enbridge uses the most recent 12 months of actual consumption, unadjusted."

Development of Forecast

a) Under what circumstances would Enbridge adjust the last 12 months actuals prior to providing customers with their monthly forecast for MDV establishment?

b) Please provide the Enbridge approved forecast and actual for FRPO DPA6331 for the gas years of November 1st - October 31st for the periods of 2004/05, 2005/06, 2006/07.

RESPONSE

a) If a billing or consumption adjustment was made early enough in the year that enabled EnTRAC to account for it, the adjustment value would be considered in the determination of the new MDV. However, if an adjustment happens too late in the contract term for EnTRAC to consider it before the pool MDV locks for flow and the customer/broker doesn't alert Enbridge to it, the MDV will be established without having considered the adjustment. Once a pool locks for flow (30 days prior to its flow date) we wouldn't allow further adjustment to the MDV.

b) The following table shows the consumption estimates that would have been provided by DPA 6331 as compared to the actual consumption.

Pool Term	Annual Estimated Consumption	Annual Actual Consumption
Nov 1/04 – Oct 31/05	21,201,040	20,786,782
Nov 1/05 – Oct 31/06	20,487,812	19,326,542
Nov 1/06 – Oct 31/07	18,448,618	17,116,640

Witnesses: I. MacPherson
B. Manwaring

FRPO INTERROGATORY #2

INTERROGATORY

Ref: Exhibit E1, page 35, para. 113 “Enbridge DP customers must take specific actions at the end of their DP contract to bring their BGA into balance although they have an opportunity to do so during the year with some restrictions depending on the time of year.

DP Balancing

a) What criteria are used by Enbridge to determine if Direct Purchase customers have an opportunity to suspend? Please specify the attributes that are considered in the determination.

b) Please provide the actual periods of restriction in the past 4 years.

c) Please provide a table of the “BGA Disposition Gas Purchase and Sales Rates” on a monthly basis from Oct. 31/05 to Oct. 31/07.

d) If gas in excess of the 20 days limit is purchased by the company, how are the volumes and costs treated?

e) If additional gas is needed to bring the DPA up to 20 days short, where is the gas provided from and how are the revenues and costs treated?

RESPONSE

a) As explained at the Technical Conference (Tr. p. 146 to 149) there is a cross-functional team that meets on a regular basis to review near term projections of supply and demand, make decisions to adjust the levels of seasonal supply if necessary. This team reviews the BGA positions to determine if there is a need for suspensions and/or makeups. The team, after looking at the near term projections of supply and demand, determines whether we can offer suspensions and/or makeups without affecting storage targets and meeting customers’ demands and establishes a level of suspensions and/or makeup that will be made available on a go forward basis which is then allocated to the DP customers on a first come first served basis.

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

b) The actual periods of restriction in the past years are noted in the table below commencing with the implementation of Phase 2 of EnTRAC in January of 2005. A zero indicates that no allowance was available in that month. A numeric entry represents the total cubic meter volume that would have been made available on a first come, first served basis.

	Empress makeup	CDA makeup	EDA makeup	Empress suspension	CDA suspension	EDA suspension
Jan 2005	6,200,000	13,708,200	6,854,100	0	0	0
Feb 2005	5,600,000	9,286,200	9,286,200	0	0	0
Mar 2005	7,685,000	9,617,850	9,617,850	0	0	0
Apr 2005	7,950,000	9,949,500	9,949,500	7,950,000	41,726,744	1,393,368
May 2005	4,929,000	15,500,000	5,062,300	8,215,000	40,300,000	806,000
Jun 2005	4,770,000	15,000,000	4,899,000	7,950,000	19,140,000	750,000
Jul 2005	4,929,000	15,500,000	5,062,300	8,215,000	20,783,000	2,952,400
Aug 2005	3,289,968	15,500,000	5,062,300	6,579,967	19,778,000	775,000
Sep 2005	3,183,840	15,000,000	4,899,000	6,367,710	18,568,000	1,322,000
Oct 2005	3,289,968	15,500,000	5,062,300	6,579,967	27,900,000	886,600
Nov 2005	3,183,840	15,000,000	4,899,000	6,367,710	18,434,000	4,221,000
Dec 2005	3,289,968	15,500,000	5,062,300	4,092,000	10,638,000	1,702,000
Jan 2006	3,289,968	15,500,000	5,062,300	9,490,000	23,600,000	0
Feb 2006	3,065,456	14,000,000	4,564,000	0	0	0
Mar 2006	589,000	15,500,000	5,062,300	4,245,120	19,103,040	2,387,880
Apr 2006	3,183,840	14,909,100	3,000,000	7,959,600	31,838,670	3,979,800
May 2006	3,289,968	15,406,070	3,100,000	8,224,920	43,687,277	5,662,460
Jun 2006	3,183,840	8,976,741	323,652	11,939,430	45,507,990	2,250,000

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

	Empress makeup	CDA makeup	EDA makeup	Empress suspension	CDA suspension	EDA suspension
Jul 2006	3,289,968	7,182,259	366,435	16,449,840	42,444,123	6,913,000
Aug 2006	3,289,968	8,990,713	385,764	16,449,840	57,526,489	6,482,326
Sep 2006	3,183,840	15,437,823	1,267,658	11,939,490	58,657,140	8,482,500
Oct 2006	3,289,968	9,748,409	285,764	12,337,473	33,376,097	7,051,344
Nov 2006	3,979,830	8,939,490	3,000,000	7,959,660	25,838,670	6,000,000
Dec 2006	4,112,491	9,237,473	3,100,000	0	13,266,125	0
Jan 2007	4,112,491	9,237,473	3,100,000	0	18,359,750	4,722,978
Feb 2007	2,971,612	8,343,524	2,800,000	5,943,224	33,272,568	11,301,584
Mar 2007	3,289,999	9,237,473	3,100,000	4,112,491	11,544,408	793,096
Apr 2007	3,979,830	11,939,490	0	7,959,660	11,939,490	0
May 2007	4,112,491	8,380,013	6,716,782	8,702,574	32,899,959	12,337,504
Jun 2007	3,979,830	403,620	1,620	7,959,660	23,879,010	11,939,520
Jul 2007	6,579,998	0	0	6,579,998	35,951,162	12,337,504
Aug 2007	6,579,998	0	0	8,224,982	46,139,564	8,490,315
Sep 2007	3,979,830	0	0	3,979,830	39,002,400	3,979,830
Oct 2007	4,112,491	0	0	8,224,982	33,297,942	8,030,213
Nov 2007	0	0	0	3,449,186	6,898,372	3,151,304
Dec 2007	4,112,491	4,112,491	3,588,682	0	0	0

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

c) The table below provides the “BGA Disposition Gas Purchase and Sales Rates” on a monthly basis from October 31, 2005 to October 31, 2007.

12 Months Ending	EnTRAC BGA Gas Purchase Price Using 80% daily average AECO price less T-Service Credit For 12 months ending $ / m^3	EnTRAC BGA Gas Sale Price Using 120% daily average AECO price For 12 months ending $ / m^3
31-Oct-2005	0.198131	0.360755
30-Nov-2005	0.211293	0.379438
31-Dec-2005	0.220927	0.392795
31-Jan-2006	0.235475	0.413696
28-Feb-2006	0.240787	0.420834
31-Mar-2006	0.242980	0.423202
30-Apr-2006	0.241483	0.420284
31-May-2006	0.239287	0.416294
30-Jun-2006	0.236615	0.411612
31-Jul-2006	0.233127	0.405684
31-Aug-2006	0.229640	0.399758
30-Sep-2006	0.221145	0.386342
31-Oct-2006	0.202707	0.358384
30-Nov-2006	0.187200	0.334833
31-Dec-2006	0.179284	0.322659
31-Jan-2007	0.166405	0.303041
28-Feb-2007	0.163287	0.298092
31-Mar-2007	0.164886	0.300190
30-Apr-2007	0.166515	0.302889

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

12 Months Ending	EnTRAC BGA Gas Purchase Price Using 80% daily average AECO price less T-Service Credit For 12 months ending $ / m^3	EnTRAC BGA Gas Sale Price Using 120% daily average AECO price For 12 months ending $ / m^3
31-May-2007	0.168523	0.306165
30-Jun-2007	0.172098	0.311784
31-Jul-2007	0.173479	0.314119
31-Aug-2007	0.171145	0.310883
30-Sep-2007	0.168222	0.306753
31-Oct-2007	0.170011	0.309893

d) Gas in excess of the 20 day limit is purchased by the Company and is captured in the PGVA.

e) EGD presumes that FRPO is referring to the customer's BGA in this Interrogatory. It is the customer's responsibility to manage their BGA balance. If additional gas is required to bring it up to or within the 20 days tolerance, the customer would use the standard BGA management mechanisms of Make Up deliveries, Title Transfers, or Enhanced Title Transfer.

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

FRPO INTERROGATORY #3

INTERROGATORY

Ref: Exhibit E1, page 33, para. 109
“Enbridge uses a variety of tools to meet seasonal and peak winter demands:
- company and DP daily pipeline deliveries;
- gas in storage space and associated deliverability;
- peaking and seasonal supplies; and
- gas supplies from curtailed (interruptible) large volume customers.

System Gas Management

a) Does Enbridge bring in planned system gas deliveries in equal daily deliveries throughout the year?

b) If not, are additional winter deliveries planned and procured? How are the winter premium costs treated from an allocation point of view?

RESPONSE

a) As part of the gas supply plan, EGD budgets to use its long haul transportation contracts at 100 % load factor (e.g., TCPL, Alliance and Vector). This component of supply is planned to be received in equal daily deliveries throughout the year.

b) The gas supply plan also includes other seasonal and peaking supplies to meet winter demand and summer storage injection requirements. Premium paid for these supplies are recovered from load balancing charges for all customers.

Witnesses: J. Collier
A. Kacicnik
M. Suarez

FRPO INTERROGATORY #4

INTERROGATORY

Ref: Exhibit E1, page 33, para. 109
"Enbridge uses a variety of tools to meet seasonal and peak winter demands:

- company and DP daily pipeline deliveries;
- gas in storage space and associated deliverability;
- peaking and seasonal supplies; and
- gas supplies from curtailed (interruptible) large volume customers.

Forecast of Functional Requirements

a) To meet the expected requirements for volumes of gas to get through the winter season, does Enbridge forecast the monthly volume requirements of the respective functions of system gas, load balancing gas (both system and DP balancing) and company used gas separately?

b) How is the storage allocation for each function determined?

c) Are the actual storage balances for each function maintained separately?

RESPONSE

a) No, the gas supply planning is done in aggregate but takes into account the DP customers MDV deliveries. The adoption of check point balancing in the management of BGAs would not change the gas supply planning in aggregate (i.e., bundled System and DP customers).

b) n/a

c) No, because there is no need to do so. EGD does the load balancing for all bundled customers and DP customers return gas molecule through the annual BGA disposition process.

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

FRPO INTERROGATORY #5

INTERROGATORY

Ref: Exhibit E1, page 33, para. 109
"Enbridge uses a variety of tools to meet seasonal and peak winter demands:
- company and DP daily pipeline deliveries;
- gas in storage space and associated deliverability;
- peaking and seasonal supplies; and
- gas supplies from curtailed (interruptible) large volume customers.

System Gas Balancing

a) What criteria are used to manage the integrated pool to determine if it is long or short?

b) If the integrated pool is short gas relative to forecast, how does Enbridge determine which function has caused the apparent insufficiency?

c) Does Enbridge have a published protocol in evidence?

d) Is there discretion afforded management to determine the underlying source of difference to forecast?

RESPONSE

a) By "integrated pool" EGD interprets this to mean the aggregate bundled system and DP customers. The gas in storage targets established as part of the gas supply plan are the main criteria used to determine any changes to planned seasonal purchases.

b) Enbridge provides load balancing for all its ratepayers and takes corrective action in its seasonal supplies acquisitions. If EGD is short or long on supplies it is usually due to weather variations relative to the plan. Both DP and system customers consumption would be different to that assumed in the plan and both groups would be out in the same direction. Please also see the response to IGUA Interrogatory 3(b) at Exhibit IR11, Schedule 3.

c) There is no protocol per se. There are gas supply planning processes and ongoing operational processes to ensure that the firm demand of all its customers are met in a cost effective manner.

d) Please see response in b) above.

Witnesses: M. Giridhar
D. Small

FRPO INTERROGATORY #6

INTERROGATORY

Ref: Exhibit E1, page 33, para. 109
"Enbridge uses a variety of tools to meet seasonal and peak winter demands:

- company and DP daily pipeline deliveries;
- gas in storage space and associated deliverability;
- peaking and seasonal supplies; and
- gas supplies from curtailed (interruptible) large volume customers.

Functionalization and Allocation of Balancing Costs

a) If gas is sold or purchased to meet the established criteria, how is the cost consequences of any discounts or premiums tracked?

b) If a deferral account is used, what criteria is in place to ensure the cost causality principle for the system gas program and the distribution functions?

c) Are those criteria published in evidence?

RESPONSE

a) Cost premiums or discounts for gas purchases relative to the reference price are recorded in the PGVA. Enbridge does not sell gas other than to its retail customers, rather it holds enough flexibility in the form of discretionary Dawn supplies in its portfolio to respond to lower (or higher) than forecast demand.

b) The cost causality principle is maintained by ensuring that the composition of deferral / variance accounts and the methodology used to determine deferral / variance account balances are directly linked to how such costs are recovered in rates in the first place.

c) Please see Enbridge's evidence at Exhibit E1, Issue 4: Deferral and variance accounts and disposition methodology, Paragraphs 47 to 57, pages 15 to 20.

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

FRPO INTERROGATORY #7

INTERROGATORY

Ref: Exhibit E1, page 33, para. 109
"Enbridge uses a variety of tools to meet seasonal and peak winter demands:

- company and DP daily pipeline deliveries;
- gas in storage space and associated deliverability;
- peaking and seasonal supplies; and
- gas supplies from curtailed (interruptible) large volume customers.

System Gas Transportation Implications

a) If the system gas program is long gas in the winter period, what is Enbridge's planned approach to dealing with the transportation associated with the unneeded gas supply?

b) If UDC is incurred, does the system supply program pay for the cost or is it paid for by a distribution or transportation account?

c) Was Enbridge required to shed system supply gas in the winter of 2006-2007?

d) Was UDC incurred?

e) How was it paid?

f) Was the transport used by any other functional area of Enbridge?

g) If so, which area?

h) If not, did Enbridge sell the rights in the secondary market and what were the resulting cost consequences?

RESPONSE

a) and b)

When EGD develops its supply portfolio it uses a combination of contracted long haul capacity and a level of uncontracted seasonal supplies. If it is warmer than budget, EGD will not acquire seasonal supplies so that we are able to maintain operating our long haul pipeline contracts at 100% and thereby not incur UDC.

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

b) EGD operated its long haul contracts at 100 % during the winter of 2006-07

c) No, it was not required.

d) n/a

e) n/a

f) n/a

g) n/a

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

FRPO INTERROGATORY #8

INTERROGATORY

Ref: RP-2003-0203, Tab 5, Sch 3, page 2, para. 4 "The Company identified and included the following functions which support the management of system gas based on fully allocated costing: Gas Acquisition, Risk Management, Contract Management, Nominations, Invoicing, Payment and Reporting, Billing (including CIS hosting costs), Collections, and Call Center. The Billing, Collection, and Call Center functions and their associated costs have been included in the fully allocated costing approach. The inclusion of these functions in the determination of the fully allocated cost recognizes that some of the activities, carried out for all distribution services, also support system gas sales. However, the costs associated with these functions are not incremental to the Company and would still be incurred in the event the Company no longer managed system gas. Based on a fully allocated costing methodology, the 2005 system gas service cost would be $14,725,000.

Level Playing Field between Administration Costs of System Gas and Retail

a) Please provide the scope of recovery for the system gas management fee.

b) Please provide the scope of recovery for the Agency, Billing and Collection (ABC) service for retailers who choose ABC.

c) Please provide the scope of recovery for the Direct Purchase Administration Charge.

d) Please provide current rates for each of the above services.

e) Please provide a comparison to the system gas fee that demonstrates the principle of level playing field between system gas customers and direct purchase customers who pay the DPAC and ABC charges.

RESPONSE

a) and c)

Please see Enbridge's evidence at Exhibit E1, Page 47, Issue 9.1: What activities and underlying costs should be incorporated into the regulated gas supply and direct purchase options.

b) ABC is a non-utility service and outside the scope of this proceeding.

Witnesses: J. Collier
A. Kacicnik
M. Suarez

d) System Gas Charges: As per October 1, 2008 QRAM (EB-2008-0263) for Rate 1 (i.e. residential) customers:

System gas fee = 0.0185 c/m3.

A unit rate fee inclusive of commodity-related bad debt expense and working cash requirement as well as the system gas fee = 0.2213 c/m3

Gas supply charge (commodity plus unit rate fee from above) = 33.7551 c/m3

Direct Purchase Administration (DPAC) Charges:

Base Charge = $50.00 per pool per month
Maximum Charge = $815.00 per pool per month

Account Charge
New Accounts = $0.50 per month per account
Renewal Accounts = $0.15 per month per account

ABC Charges (note: ABC is a non-utility service):

Rate 1 = $1.05 per account per month
Rate 6 = $2.00 per account per month
All other = $5.00 per account per month

e) Enbridge's gas supply charges besides commodity costs also recover commodity-related bad debt expense and working cash requirement as well as the system gas fee. These charges recover the costs of providing the regulated system gas supply option. The DPAC recovers the incremental cost of facilitating the direct purchase supply option. ABC is a non-utility service. Gas vendors can outsource billing and collection to the utility using ABC service. Note that gas vendors operate in an unregulated marketplace and can choose to perform these functions themselves or outsource them to a service provider.

The regulated supply and direct purchase options are separate and different. The approach described in the paragraph above provides for no cross subsidy / level playing field between the system gas (i.e., the regulated supply option) and direct purchase options.

Witnesses: J. Collier
A. Kacicnik
M. Suarez

FRPO INTERROGATORY #9

INTERROGATORY

Ref: Exhibit E1, page 49, para. 170 "In contrast, a fully-allocated approach to costing would necessitate the recovery of other costs through system gas and DPAC fees which are not directly related to the service. Should a fully-allocated approach be pursued in the costing of system supply and direct purchase management, if customers opted to select one option versus the other, fully allocated costs would not be recovered because the elimination of the service would not eliminate the cost. Ref: RP-2003-0203, Tab 5, Sch 3, page 2, para. 4 (included above)

Utility Risk of Under-Recovery

a) Please provide the total annualized cost of system gas for 2006 and 2007.

b) Please provide any more recent cost study figure for the fully allocated and incrementally allocated cost of the gas supply administration fee.

c) If, after establishment of a QRAM price, system gas volumes decreased by 5% due to customer migration in that quarter relative to forecast yet the cost of gas was exactly the same as forecast leading to an under-recovery of around 5%, would Enbridge be at risk for non recovery of that amount?

RESPONSE

a) The total annualized forecast cost of system gas, inclusive of commodity costs, commodity-related bad debt expense, and working cash requirement, as well as system gas fee, are provided below. These costs are recovered through the gas supply charge which is paid by system gas customers only.

2007 = $1,621,543 thousand (Final Board Order, EB-2006-0034)
2006 = $2,114,691 thousand (Final Board Order, EB-2005-0001)

b) Please see the Company's evidence at Exhibit E1, Paragraph 173, page 50 for an illustration of 2009 system gas fee on incremental cost basis. The Company has not conducted a fully allocated study regarding system gas fees since Enbridge's 2005 Test Year Rate Case, RP-2003-0203.

Witnesses: J. Collier
A. Kacicnik
M. Suarez

c) No, Enbridge makes adjustments to its system gas supplies to reflect actual migration to or from the direct purchase option on an ongoing basis. The PGVA captures the variance between Enbridge's actual cost of gas purchases and the forecast.

Witnesses: J. Collier
A. Kacicnik
M. Suarez

IGUA INTERROGATORY #1

INTERROGATORY

Issue 4.3

Ref: Exhibit E1, pages 16-18

a. EGD indicates at paragraph 53 that under its proposal to adopt Union's methodology for disposing of amounts in the PGVA, it will identify on a quarterly basis the elements of the PGVA attributable to commodity, transportation and load balancing and then determine individual riders to apply to sales service, western bundled T-service and Ontario T-service customers. Please list the elements of the PGVA that would be included in the riders for western bundled T-service customers and for Ontario T-service customers.

b. With reference to paragraph 51, please provide for the years 2005 to 2007 the amounts by PGVA component that were determined to be attributable to direct purchase customers. Please provide an estimate of these same components for 2008.

c. Has EGD discussed with its large-volume T-service customers, its proposal to adopt Union's methodology for disposing of amounts in the PGVA? If yes, please summarize the feedback received from those customer discussions. If no, what are EGD's plans for communicating with its customers on this proposal?

RESPONSE

a) Please see the response to Board Staff Interrogatory #3 at Exhibit IR24, Schedule 3.

b) Please see the total year end PGVA balance which was cleared as a year end adjustment to customers and the amount attributable to direct purchase customers for the years 2005, 2006 and 2007. The Company does not have the information available for 2008.

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

COMMODITY	(87,988)	-
SEASONAL PEAKING-LOAD BALANCING	6,254	3,108
SEASONAL DISCRETIONARY-LOAD BALANCING	3,528	1,854
TCPL TOLL CHANGE	4,454	2,152
CURTAILMENT REVENUE	(347)	(173)
RIDER ADJUSTMENT DIRECT ALLOCATION	126,209	-
INVENTORY ADJUSTMENT	(58,594)	-
Total PGVA	(6,484)	6,941

2006 PGVA Balance Including Interest

	Total PGVA ($000)	Direct Purchase ($000)
COMMODITY	660	-
SEASONAL PEAKING-LOAD BALANCING	(1,257)	(637)
SEASONAL DISCRETIONARY-LOAD BALANCING	(22,536)	(11,918)
LINK PIPELINK-LOAD BALANCING	(288)	(90)
CURTAILMENT REVENUE	(336)	(336)
RIDER C ADJUSTMENT DIRECT ALLOCATION 2006	33,256	-
INVENTORY ADJUSTMENT	8,128	-
TCPL TRANSPORTATION CAPACITY CREDIT	(73)	(35)
Total PGVA	17,554	(13,016)

2007 PGVA Balance Including Interest

	Total PGVA ($000)	Direct Purchase ($000)
COMMODITY	(21,502)	-
SEASONAL PEAKING-LOAD BALANCING	340	180
SEASONAL DISCRETIONARY-LOAD BALANCING	3,663	1,947
LINK PIPELINE	(93)	(56)
TCPL TOLL CHANGE	17	8
CURTAILMENT REVENUE	(19)	(19)
RIDER C 2007 DIRECT ALLOCATION	20,925	-
INVENTORY ADJUSTMENT	4,286	-
Total PGVA	7,617	2,060

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

c) No, the Company has not had discussions with its large volume customers. The Company is proposing to implement any changes relating to the proposed PGVA clearing as part of its 2010 rate adjustment application (this would be the earliest opportunity depending on the timing of the Board decision in this proceeding). If approved, the Company would inform its large volume customers during its annual large volume customer meetings which are typically held in June.

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

IGUA INTERROGATORY #2

INTERROGATORY

Issues 5.1 and 5.2

Ref: Exhibit E1, pages 20-25

Please list all of the components of the revenue requirement that are adjusted as part of the quarterly rate adjustment mechanism and categorize them according to delivery, load balancing, transportation, and gas supply.

RESPONSE

As part of a QRAM application, the following rate base related components of revenue requirement are adjusted and classified in the following manner.

Expense	Classification
Return in Gas in Inventory	Load Balancing
Gas Costs Working Cash and GST	Gas Supply
Capital and Large Corporation Taxes	Load Balancing

Witnesses: J. Collier
K. Culert
A. Kacicnik

IGUA INTERROGATORY #3

INTERROGATORY

Issue 8.1

Ref: Exhibit E1, pages 31-39

a. In paragraphs 101 and 104, EGD refers to gas being purchased or sold at a price that compensates EGD for sourcing or disposing of gas remaining in a customer's BGA. Please demonstrate how the formula for pricing this gas compensates EGD.

b. With reference to paragraphs 110 and 111, please confirm that if half of the Rate 110 or Rate 115 customers by volume took substantially more than forecast in a cold period of the winter season while the other half took exactly their forecast volumes, all Rate 110 or Rate 115 customers would share equally in the cost of balancing.

c. With reference to paragraph 115, direct purchase customers of Union generally have an obligation to deliver gas at Union CDA. Please explain in what material way a suspension/make-up at Union CDA differs from a suspension/make-up at Enbridge CDA with respect to the benefits of trading at Dawn.

d. With reference to paragraph 120, for a February checkpoint for example, mandatory mitigation would be make-up (incremental supply) since a customer can be long but not short. Please explain how this mitigation measure would put the system supply at risk.

e. With reference to paragraph 122, please explain how there would be no benefit to ratepayers with an approach to load balancing that results in customers who have balanced their loads not having to share the cost of balancing other customers' loads.

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

RESPONSE

a) As indicated at Exhibit E1, paragraphs 101 through 105, direct purchase customers are encouraged to manage the Banked Gas Account ("BGA") balances throughout the course of a year. At the end of the contract year, if a customers BGA balance exceeds the tolerance of +/- 20 times their Mean Daily Volume ("MDV"), the Company deems to have purchased or sold that amount of gas from/to the customer. Similarly, any volume within the tolerance band must be disposed of within 180 days of the contract expiry date or it also is deemed to have been purchase or sold from/to the customer by the Company. The purchase price is Board approved, as listed in the Rate Handbook, and is equal to 80% of the average price over the contract year, based on the published index price for the Monthly AECO/NIT supply adjusted for Nova's AECO to Empress transportation tolls and compressor fuel costs, less the average Ontario Transportation Service Credit over the contract year. If the gas is deemed to have been sold it is priced at 120% of the average price over the contracted year, based on the published index price for the Monthly AECO/NIT supply adjusted for Nova's AECO to Empress Transportation tolls and compressor fuel costs. The intent of this pricing is to not only keep EGD and rate payers whole with respect to its gas costs purchases but to encourage customers to actively manage their BGA balances.

b) All customers within a rate class pay the same per unit rate for load balancing. This reflects the fact that rates are developed based on class rate making principles. These principles reflect cost causality, load/cost characteristics of each rate class, and ensure that revenues from each rate class recover costs incurred to serve each rate class. The same class rate making principles are used to determine the responsibility of a rate class as it relates to the disposition of the PGVA account. Any load balancing purchase variances between forecast and actual gas costs would get captured in the PGVA and disposed of to both system gas and direct purchase customers. All system gas and direct purchase customers within a rate class would be charged the same unit rate from PGVA disposition which would be applied to their actual volumes from the previous year.

   This approach is further illustrated below by discussing the specific scenario posed in question b).

   The average annual demand is met through MDV deliveries (i.e., the amount of gas being delivered into the franchise area through upstream pipelines is the same each and every day of the year). Hence, Enbridge needs to take action every day to balance supply and demand (see Enbridge's evidence at Exhibit E1, page 34, Figure 2).

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

Further, direct purchase market works on the principles of MDV deliveries and BGA management rules which ensure total deliveries match consumption at the end of each contract year (other than the BGA tolerance). Enbridge provides load balancing and distribution service to both system gas and direct purchase customers.

The load of Rate 110 and Rate 115 customers comprises of: heat load (i.e., heating of their manufacturing facilities/work halls and office space), base load (such as water heating) and process load (i.e. use of natural gas in a manufacturing process).

If winter is colder than the forecast, then the heating demand of Rate 110 and Rate 115 customers will be higher than the forecast. Accordingly, Enbridge will need to adjust upward seasonal/spot supplies to meet the demand of its customers each day of the colder than forecast period.

Please note that for half of Rate 110 and Rate 115 customers to take exactly their forecast loads, these customers would have to scale back their base and process loads in order to remain on forecast. Such action would not reflect practical experience.

The cost of the adjusted (i.e., additional) seasonal/spot purchases is captured in the Purchased Gas Variance Account (PGVA). These costs are passed onto both system gas and direct purchase customers through the clearing of the PGVA which is disposed off as per the Board approved methodology.

In the example above, the winter was colder then the forecast. Consequently, the demand of Rate 110 and Rate 115 customers was higher than the forecast. This would create a balance in a direct purchase customers' BGA at the end of the contract year as MDV deliveries would not match consumption over the course of the contract year. Customers can address balances in their BGAs through the mechanisms the Company provides such as make ups, title transfers, enhanced title transfers, or disposition of the BGA balances at the end of the contract year. As discussed in the response to part a), direct purchase customers are encouraged to manage their BGA balances throughout the course of a year.

c) The evidence of Union Gas at Exhibit E2, pages 43, 47 and 48 elaborates on features that allow them to offer check point balancing in the South, but not in the North. The liquidity at Dawn allows Union South customers to make alternate arrangements if their suspensions or make ups to the delivery area are interrupted. Similar to Union North, Enbridge's access to Dawn is via Union's Dawn Trafalgar system <u>and</u> TransCanada's system. Enbridge contracts for this capacity based on its peak day requirements. Accommodation of make ups and suspensions is subject to Enbridge's ability to meet franchise demand. On a peak day, if a DP customer, who suspended its deliveries, fails to deliver by not adhering to an interruption to the suspension, then Enbridge would be short of supply and unable to meet firm demands because of its lack of transportation capacity. In order to back stop suspensions and make ups, Enbridge would have to over contract in transportation capacity (and Enbridge has no intention/plans of doing so).

d) Paragraph 120 makes reference to a suspension that is interrupted. See point c) above.

e) Paragraph 122 states that there would not be an appreciable benefit to ratepayers of one approach over the other. Also see the response to part b) above.

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

IGUA INTERROGATORY #4

INTERROGATORY

Issue 8.4

Ref: Exhibit E1, page 39; Technical Conference Transcript (November 27, 2008), page 158

a. Please list the provisions associated with EGD's proposed MCV re-establishment process; e.g., who initiates the re-establishment, how is the re-establishment initiated, under what circumstances, the threshold level, etc.

b. If the provisions requested in part (a) are not available, please indicate when the specifics of the proposal will be available and on what their development depends.

RESPONSE

a) The MDV re-establishment process envisioned by Enbridge would be incorporated into the EnTRAC operation making it completely automated. The trigger for a change to the MDV would be the result of a predetermined threshold of change having taken place to the pool, for example number of customers or value of load having migrating to or from a pool. Discussion to determine the criteria for changing the MDV have not yet taken place and will not take place until the Board has determined if Enbridge should proceed. This decision is not anticipated until after April of 2009. Should the Board determine Enbridge should proceed, Enbridge would seek input from interested parties and stakeholders.

b) The provisions requested in part (a) are not available. Enbridge requires a decision by the Board to allow Enbridge to recover the costs of designing, developing and implementing such a program. Commencing the process would not be possible prior to the 4th quarter of 2009 (considering current CIS implementation time lines) due to limitations on internal and (required) contracted resources.

Witnesses: I. MacPherson
B. Manwaring

SEM INTERROGATORY #1

INTERROGATORY

Would you agree that the current QRAM structure uses a simple average of the forward curve, and that that simple average does not give any weight to the variations in consumption that customers experience throughout the seasons?

RESPONSE

The Company does not agree. The derivation of the commodity charge is based on a simple average of the 12 month forward prices at Empress. The methodology does not give weight to the variations in consumption through out the year, rather it reflects the assumption that the annual consumption is purchased equally over twelve months. This methodology is consistent with the requirement for direct purchase customers that they deliver a mean daily volume of gas equal to annual consumption/365 days and with the fact that long haul transport that is used to transport gas from Empress is used at a 100% load factor.

Witnesses: M. Giridhar
D. Small

SEM INTERROGATORY #2

INTERROGATORY

Reference: General

The term “Load Following Calculation” as it is used in the context of the next question refers to a calculation of the forward curve that weights the future monthly prices against the projected consumption requirements for that month. Would you agree that a Load Following Calculation would be more appropriate as an indication of what customers can expect to pay?

RESPONSE

The Company does not agree that the Load Following Calculation, as described above is representative of what customers can expect to pay. This is because EGD does not necessarily purchase the projected consumption requirements of its customers in the same month. The fallacy of this approach is shown at Exhibit E1, page 11.

Witnesses: M. Giridhar
D. Small

SEM INTERROGATORY #3

INTERROGATORY

Reference: Page 3, pp 9-11

Would you agree that the current QRAM does not carry within it any projected amount for the future cost of storage, transportation, and load balancing (‘Additional Non-Commodity Costs’, for the purpose of this question) for the forecast period? Would you agree that Additional Non-Commodity Costs would be a more appropriate indicator of what customers should compare to the marketplace than smoothed blended historical costs for out of phase periods?

RESPONSE

The Company does not agree. The forecast cost of storage and load balancing is adjusted through the current QRAM process and is recovered through rates applicable to system supply and bundled service direct purchase customers. The forecast cost of transportation is also adjusted through the current QRAM process and recovered through rates applicable to system supply and Western T service customers. Unforecast storage, transportation and load balancing costs are recovered through deferral account disposition.

Witnesses: M. Giridhar
D. Small

SEM INTERROGATORY #4

INTERROGATORY

Reference: General

In the consideration of an Ontario Wide Reference Price, is there any merit, from your perspective, in considering locational pricing for the various delivery zones in Ontario? If not, what obstacles do you see for such a consideration?

RESPONSE

EGD does not believe that an Ontario Wide Reference Price is appropriate precisely because the delivered cost of gas varies based on each utility's location within the province.

Witnesses: M. Giridhar
A. Kacicnik
D. Small

SEM INTERROGATORY #5

INTERROGATORY

Reference: General

In the consideration of an Ontario Wide Reference Price, is there any merit, from your perspective, in considering locational pricing for the various delivery zones in Ontario? If not, what obstacles do you see for such a consideration?

RESPONSE

Please see the response to SEM Interrogatory #4 at Exhibit IR19, Schedule 4.

Witnesses: M. Giridhar
A. Kacicnik
D. Small

SEM INTERROGATORY #6

INTERROGATORY

Can an Ontario Reference Price be created with the current level of unbundling and assignment of storage and transportation, including load balancing? If not, what are the specific steps which would need to be taken?

RESPONSE

As stated at Exhibit E1, Paragraphs 39 to 43, page 12 and14 the limitations to a single Ontario reference price relate to geography and the requirement to pass through incurred gas costs rather than the level of unbundling and load balancing.

The issue of greater unbundling and assignment of storage and related transport is not an issue in this proceeding.

Witnesses: M. Giridhar
D. Small

VECC INTERROGATORY #2

INTERROGATORY

Reference: Issue 4.1, Enbridge Evidence para.47

Preamble: It appears from the discussion that balances in Enbridge's single PGVA are allocated (i) amongst rate classes and (ii) between sales, Western Bundled T, and Ontario Bundled T customers, on the basis of established principles. Under Union's structure, however, given the nature of its services, all PGVA balances are allocated to sales customers.

Requests:

(a) Would Enbridge be able to disaggregate its current PGVA into separate accounts that would individually track variances to be allocated to sales, Western Bundled T, and Ontario Bundled T customers? Why or why not?

(b) Please discuss the advantages and disadvantages of adopting the suggested approach.

RESPONSE

a) EGD disaggregates the balance in the PGVA into commodity, transportation and load balancing components and then allocates those amounts to Sales, Western Bundled T and Ontario T-Service customers by rate class in accordance with its cost allocation methodology. Tracking the PGVA balance into separate accounts (which could not be done until an analysis of the account is performed) is unnecessary and would provide no benefit.

b) See response to part a) above.

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

VECC INTERROGATORY #3

INTERROGATORY

Reference: Enbridge Evidence para. 53

Preamble: Enbridge proposes to adopt Union's approach to clearing the PGVA by clearing the account quarterly based on a 12 month forward volume forecast, with individual riders applicable to sales, Western Bundled T, and Ontario Bundled T services.

Request: If the Union approach is adopted, so that new rates and applicable riders would be determined for each type of service quarterly, is it necessary to state, and is there any purpose for stating, the adjusted rate and adjusted rider separately for billing purposes? Why or why not? Would there be any advantage, from the perspective of bill presentation and customer acceptance, of combining the rates and applicable riders for presentation purposes? Why or why not?

RESPONSE

QRAM rate changes and applicable riders capture different impacts, are derived differently and, consequently, need to be stated separately. QRAM rate changes capture impacts stemming from changes in the forecast of gas costs. The gas cost adjustments (i.e., applicable riders) reflect the difference between the forecast gas costs collected in rates and the actual cost of gas. The difference is tracked in the Purchased Gas Variance Account ("PGVA") which provides the means of ensuring ratepayers and the Company are held whole with respect to gas costs.

Therefore, stating applicable rates and applicable rate adjustments (i.e., riders) separately on customer bills is necessary and provides for an easy reconciliation of charges and/or impacts.

Witnesses: J. Collier
A. Kacicnik

VECC INTERROGATORY #8

INTERROGATORY

Reference: General

Requests:

(a) Please provide a breakdown of residential customers over the last five years indicating the number of sales (system) customers and the number of direct purchase customers. Please also indicate approximately what percentage of Enbridge's residential customers are served via (i) sales service, (ii) Western Bundled T service, (iii) Ontario Bundled T Service and (iv) unbundled service.

(b) If known or if the information is available, for each of the last five years please provide the number of residential customers that migrated from being system sales customers to become direct purchase customers.

(c) If known or if the information is available, for each of the last five years please provide the number of residential customers that returned to system sales service from the direct purchase option.

RESPONSE

(a) Please see Table 1 on the next page for the requested information. Due to a limitation in the legacy billing system, Table 1 only presents the information by sales service and total direct purchase (or total bundled T-service). As the Company does not provide unbundled services to residential customers, there are no residential unbundled customers on the system.

Witness: I. Chan

TABLE 1 - RESIDENTIAL CUSTOMER METERS
2003-2007 ACTUAL

Item No.		Col. 1 2003 Customers (Average)	Col. 2 2004 Customers (Average)	Col. 3 2005 Customers (Average)	Col. 4 2006 Customers (Average)	Col. 5 2007 Customers (Average)
General Service						
1.1.1	Residential - Sales	882 007	941 826	972 744	981 599	1 019 738
1.1.2	Total Residential - Direct Purchase	608 079	599 474	613 199	648 637	650 448
1.1	Total Residential	1 490 086	1 541 300	1 585 943	1 630 236	1 670 186

Item No.		2003 Customers (Percentage)	2004 Customers (Percentage)	2005 Customers (Percentage)	2006 Customers (Percentage)	2007 Customers (Percentage)
General Service						
2.1.1	Residential - Sales	59.19%	61.11%	61.34%	60.21%	61.06%
2.1.2	Total Residential - Direct Purchase	40.81%	38.89%	38.66%	39.79%	38.94%
2.1	Total Residential	100.00%	100.00%	100.00%	100.00%	100.00%

(b) The information is not available.

(c) The information is not available.

BOARD STAFF INTERROGATORY #1

INTERROGATORY

Ref: Exhibit E1, page 12, paragraph 37

a) Please provide an estimate, with supporting explanatory comment, of the regulatory, administrative, IT billing system, and communication costs that would arise as a result of introducing a monthly reference price adjustment based on a 12 month forecast period, and a 12 month deferral disposition period.

RESPONSE

The Company is not supportive of a monthly price adjustment frequency.

Should the Board decide in favor of a monthly price change frequency, the Company estimates it would incur incremental annual expenses of at least $1.5 - $2.0 million. A high-level breakdown of these estimated costs is as follows:

Customer Care:	
Incremental Employee Salaries	$100K
Application Support	$240K
CCSA Charges (Call Centre: estimated 100,000 calls @ $5.00/Call)	$500K
Customer Communication (Bill Messages, inserts, website updates)	$30K
Public and Government Affairs:	
Incremental Employee Salaries	$100K
Design Work	$15K
Translation	$5K
Printing	$450K
Recycling	$5K
Regulatory Affairs:	
Incremental Employee Salaries	$300K
Gas Cost:	
Incremental Employee Salaries	$100K
Margin Budgets and Accounting:	
Incremental Employee Salaries	$100K

Witnesses: I. Abbasi
A. Kacicnik

In addition to the above recurring costs, the Company estimates a one time expense of $35K for a two panel insert to communicate to customers the Board decision to introduce monthly price change frequency.

Also, the revenue the Company generates from third party bill inserts would be impacted by the monthly price change frequency if the current rule stipulating no third party inserts with rate notices continues to apply. Third parties using bill insert service would also be impacted.

Witnesses: I. Abbasi
A. Kacicnik

BOARD STAFF INTERROGATORY #3

INTERROGATORY

Ref: Exhibit E1, page 18, paragraph 53

a) Please provide in detail the methodology that EGD would use to determine the balances in the PGVA that are attributable to commodity, transportation and load balancing costs.

b) Please provide an illustrative example of how this methodology would be applied.

RESPONSE

a) EGD's methodology for disposing of costs in its PGVA is consistent with the manner in which these costs are recovered in rates. EGD would use its existing Board approved methodology which it uses to clear the balances of its PGVA at fiscal year end. The existing methodology is to clear the projected balance in this account on an interim basis through a sales service rider (Rider C), through quarterly rate adjustments (QRAMs). The one-time year end adjustment allows for a true up of interim collections and a detailed analysis of the variances in individual components of the PGVA and their allocation to different types of service, including sales service. The Company's proposal is to prepare the analysis of the individual components of its PGVA within each QRAM application.

The Board approved methodology for clearing each component of the PGVA is as follows:

The account records:

i) variances in the purchases of commodity;

ii) variances in TransCanada PipeLines ("TCPL"), Alliance and Vector tolls;

iii) amounts related to electronic bulletin boards;

iv) voluntarily incurred Unabsorbed Demand Charges ("UDC");

v) variances related to TransCanada Storage Transportation Services ("STS");

vi) variance in the Inventory Valuation Adjustment Rider ("Rider C");

Witnesses: M. Giridhar
A. Kacicnik
D. Small
M. Suarez

vii) unforecast penalty revenues received from interruptible customers who did not comply with the Company's curtailment requirements and unauthorized overrun gas revenue;

viii) costs consequences associated with Vector and Alliance pipelines, net of revenues from the sale of excess capacity to third parties; and

ix) Banked Gas Account Balance disposition amounts.

Any variance associated with the commodity cost of gas, exclusive of the seasonal supply component identified below, including variances arising as a result of indexed pricing, use of electronic bulletin boards, and voluntarily incurred UDC. These variances will be cleared to all system supply customers, including buy/sell customers on a volumetric basis.

Any variance associated with seasonal supplies within the commodity component of the PGVA will be separated into a commodity and a load balancing component, based on the methodology established for the classification of purchases and receipts. This methodology essentially consists of deeming the commodity component of all supplies in its portfolio to be equal to the amount derived by reducing its FT-WACOG by the TCPL 100% load factor demand and commodity tolls. The seasonal supplies are defined as the sum of the forecast variance associated with peaking supplies and Ontario and U.S. discretionary supplies offset by unauthorized overrun gas revenue. The load balancing portion of seasonal service supplies will be cleared to all customers, including T-service customers. The load balancing variance associated with peaking supplies will be classified as peak and allocated based on the rate class responsibility for bundled peak deliveries. The load balancing variance related to discretionary supplies will be classified as pipeline seasonal and allocated to all customers using the seasonal space allocator. The remaining seasonal commodity balance will be cleared to system sales customers on a volumetric basis.

Any variance in TCPL tolls will be cleared to all customers except for non ABC Ontario Bundled T-service customers since they already have been subjected to the new transportation tolls and have been compensated for transportation at the Company's budgeted level through the Transportation Service Rider. The commodity and demand toll variance will be allocated volumetrically to the above group of customers.

Witnesses: M. Giridhar
A. Kacicnik
D. Small
M. Suarez

Non-compliance revenues included in the PGVA will be applied as an offset to the peaking supply variance and to interruptible customers, using a 50/50 ratio. This recognizes that as a result of non-compliance, in the case of both curtailment for seasonal and daily balancing, additional delivered supplies may be purchased, the incremental costs of which are included in the PGVA. Failure to comply could also cause additional curtailment on the part of other complying interruptible customers. The relative proportions to which each of these options is employed will vary depending on the particular circumstances experienced and is virtually impossible to quantify. This methodology directs the non-compliance revenues to both firm and interruptible customers. The revenues offsetting the peaking supply variance will be allocated to all customers using the bundled peak delivery allocator. The revenues flowing to interruptible customers will be apportioned between Rate 145 and Rate 170 prorata to their respective global contract demand, as the use of the bundled peak delivery allocator for these rate classes would result in allocating disproportionate benefits to Rate 145.

The variance stemming from STS will be cleared to all customers using the deliverability allocator.

The forecast amounts to be collected from (or refunded to) all customers through Rider C during the QRAM process will be allocated to customers by component. These components include forecast commodity variance and the forecast inventory adjustment. The forecast commodity variance is allocated to system and buy/sell customers based on volumetric consumption. The forecast inventory adjustment is allocated to system and buy/sell customers based on the rate class responsibility for inventory space. The actual amounts recovered through Rider C will be directly assigned to the applicable customer rate class and credited to all customers.

Vector and Alliance costs will be recorded as an offset to the revenue received for marketing its capacity to third parties through its Transactional Service offerings. The net balance will be classified and allocated on the basis of 100% annual deliveries.

b) Please see the response to IGUA Interrogatory #1 at Exhibit IR11, Schedule 1, part b) for an illustrative example.

Witnesses: M. Giridhar
A. Kacicnik
D. Small
M. Suarez

BOARD STAFF INTERROGATORY #4

INTERROGATORY

Ref: Exhibit E1, page 36, paragraph 117

a) Please provide the proposed threshold for changes to the MDV and the rationale for the proposed threshold.

b) If the proposed threshold is not available at this time, please indicate when Enbridge expects that it will become available.

c) Is Enbridge proposing that the threshold be set at its discretion? If so, what is the benefit of that approach relative to an approach where the threshold would be pre-defined?

RESPONSE

a) A threshold has not been developed at this time.

b) It is expected that a threshold would be determined (after having sought input from stakeholders and interested parties) during design sessions which would not be scheduled until Enbridge has received approval to proceed with this initiative by the Board. Enbridge is cognizant of harmonization objective, so anticipate establishing the threshold at similar or the same value as Union's threshold unless there are considerations that make doing so impractical.

c) See response to b).

Witnesses: B. Manwaring
D. Small

BOARD STAFF INTERROGATORY #6

INTERROGATORY

Ref: Exhibit E1, page 50, paragraph 173

a) Please confirm that Enbridge will be seeking Board approval to adjust the system gas fee and direct purchase management costs in its 2010 rate adjustment application.

RESPONSE

The Company supports the incremental costing approach and will seek Board approval of its updated system gas and direct purchase management fees in its 2010 rate adjustment application.

Witnesses: J. Collier
A. Kacicnik

BOARD STAFF INTERROGATORY #7

INTERROGATORY

Ref: Exhibit E1, page 51, paragraph 178

a) Please confirm that Enbridge will be seeking Board approval to adjust the DPAC structure in its 2010 rate adjustment application.

RESPONSE

This is confirmed.

Witnesses: J. Collier
A. Kacicnik

BOARD STAFF INTERROGATORY #8

INTERROGATORY

Ref: Exhibit E1, page 55, paragraph 193

a) Did the focus group discussions include feedback on the line item of the bill that deals with the disposition of the PGVA (i.e. gas cost adjustment)?

b) If so, what was the outcome?

RESPONSE

a) & b)
The focus groups were provided sample bills for system gas and direct purchase customers that included various combinations of pay as you go, budget billing, pre-authorized payment and charges from other energy companies. Enbridge tested the description of all bill charges. Focus groups did not include scenarios with gas cost adjustment.

Witness: A. Creery

BOARD STAFF INTERROGATORY #9

INTERROGATORY

Ref: Exhibit E1, page 58, paragraphs 202-209

a) Please provide all calculations and supporting documentation in respect of the estimated implementation costs provided under Issue 11.1.

RESPONSE

Trigger Mechanism:

The elimination of the trigger mechanism will not lead to additional costs or savings as the Company will continue to follow processes that it normally carries out every quarter.

Deferral and Variance Accounts and Disposition Methodology:

The Company is proposing to dispose of PGVA balances using a 12-month rolling rider methodology. This change will require communication with customers to inform them about the change. While the Company would use regular communication channels to convey the changes to ratepayers, an additional one time expense of approximately $100,000 is anticipated to cover the incremental printing, design, and communication costs.

Multipoint Balancing:

The following is based on estimates that would result from adoption of a multi point balancing model. These estimates are high level and the list is not to be interpreted as exhaustive or complete as it was prepared in absence of a formal/detailed evaluation. As noted in the Company's evidence at Section B, the Company is not proposing to implement multipoint balancing.

Design and Development	
Including scoping study, transaction rules, programming development, test and warranty.	$5,000,000

Witnesses: I. Abbasi
A. Kacicnik

Infrastructure Changes to internal processes, documents, staffing, controls (Sox), contracts, training and testing, synchronization with other programs	$1,250,000
3rd Party Development, Training and Communications Any impacts from integration and testing with other systems and/or programs such as SAP	$1,250,000
Project Management	$500,000
Contractor Expenses Travel, living, administration	$500.000
Sum	$8,500,000

MDV Re-establishment:

The following is based on estimates that would result from adoption of an MDV re-establishment process. These estimates are high level and the list is not to be interpreted as exhaustive or complete as it was prepared in absence of a formal/detailed evaluation.

Design and Development Including scoping study, transaction rules, hardware and software development including development of an appropriate weather normalization program	$2,650,000
Infrastructure Changes to internal processes, documents, contracts	$550,000
Project Management	$250,000
Contractor Expenses Travel, living, administration	$250.000
Sum	$3,700,000

Witnesses: I. Abbasi
A. Kacicnik

Price Adjustment Frequency:

Please see the response to Board Staff Interrogatory #1 at Exhibit I24, Schedule 1.

Billing Terminology:

Costs to implement Billing Terminology changes would be at least $0.6 million. This would include system changes to change Enbridge's current terminology to match with Union Gas (or terminology determined by the Board). Additionally, updates would be required to all of Enbridge's existing communication materials such as new customer packages, changes to the Company's website and change to the Rate Handbook. Training of Company's service providers would also be required.

A high-level breakdown of the estimated costs is as follows:

System Change	100,000	Implementation of code changes
Communication	247,000	Bill inserts re: description of changes
Update Existing Materials	100,000	Cost of updating plus French translation service
Training of Service Providers	200,000	Training costs
	647,000	

Witnesses: I. Abbasi
A. Kacicnik