Enbridge Gas
2007 Test Year Rate Case

EB-2006-0034

EXHIBIT LIST

Exh. K	**Exhibits filed at the Hearing**	**Date Filed**
	No exhibits and undertakings were filed	**January 22, 2007**
K 2.1	TABLE FORMING PART OF ENBRIDGE'S INTERROGATORY NO. 3 TO ENERGY PROBE, AND TABLE 1 AT EXHIBIT L, TAB 5, SCHEDULE 1 FROM THE PREFILED EVIDENCE OF TOM ADAMS	**January 29, 2006**
K 2.2	EXTRACT FROM NATURAL GAS FORUM DOCUMENT ENTITLED "NATURAL GAS REGULATION IN ONTARIO: A RENEWED POLICY FRAMEWORK", PROVIDED BY MR. BUONAGURO	
K2.3	THREE-PAGE DOCUMENT FROM PREVIOUS UNION RATES CASE, ENTITLED "RISK MANAGEMENT IMPACT ON WACOG AND PGVA"	
K2.4	ENERGY PROBE COMPENDIUM OF DOCUMENTS, ENTITLED "CROSS-EXAMINATION MATERIAL ON RISK MANAGEMENT, ENERGY PROBE RESEARCH FOUNDATION, JANUARY, 2007"	
K2.5	ENBRIDGE CUSTOMER SURVEY ON RISK MANAGEMENT	
K2.6	SPREADSHEET TITLED "ANALYSIS OF REVENUE TO COST RATIOS FOR RATE 1 AND ANALYSIS OF REVENUE TO COST RATIOS FOR RATE 6."	

Enbridge Gas
2007 Test Year Rate Case

EB-2006-0034

J	Undertakings	Response Filed
	January 29, 2007	
2.1	ADVISE WHAT STEPS, IF ANY, HAVE BEEN TAKEN BY EGD TO EDUCATE CUSTOMERS IN RATES 100 OR HIGHER ABOUT THE COMPANY'S RISK MANAGEMENT PROGRAM AND THE NECESSITY, IF ANY, FOR THOSE CUSTOMERS TO UNDERTAKE THEIR OWN RISK MANAGEMENT	
2.2	ADVISE WHETHER EGDI OBTAINS FINANCIAL INSTRUMENTS OR MECHANISMS FOR RISK MANAGEMENT PROGRAM FROM ANY AFFILIATES OR RELATED	

K2.1

Original
EB-2006-0034
Exhibit I
Tab 31
Schedule 3
Page 2of 5

d)

Impact of Risk Management on PGVA Reference Price
2002 -2006

Date	PGVA Reference Price $/10^3 m^3$	Quarterly Price Change $/10^3 m^3$	PGVA Reference Price without Risk Management $/10^3 m^3$	Quarterly Price Change $/10^3 m^3$	Variance $/10^3 m^3$	% Reduction in Quarterly Price Change
1-Jan-02	220.462		218.221			
1-Apr-02	193.523	26.94	188.783	29.44	(2.50)	8.5
1-Jul-02	252.875	59.35	254.208	65.43	(6.07)	9.3
1-Oct-02	237.963	14.91	237.963	16.25	(1.33)	8.2
1-Jan-03	259.519	21.56	259.115	21.15	0.40	(1.9)
1-Apr-03	312.877	53.36	313.439	54.32	(0.97)	1.8
1-Jul-03	n/a *	n/a	n/a	n/a	-	-
1-Oct-03	280.181	32.70	280.075	33.36	-	-
1-Jan-04	263.197	16.98	262.337	17.74	(0.75)	4.2
1-Apr-04	292.891	29.69	293.175	30.84	(1.14)	3.7
1-Jul-04	332.911	40.02	334.344	41.17	(1.15)	2.8
1-Oct-04	332.236	0.67	332.236	2.11	(1.43)	68.0
1-Jan-05	356.327	24.09	358.784	26.55	(2.46)	9.3
1-Apr-05	319.285	37.04	318.199	40.58	(3.54)	8.7
1-Jul-05	355.705	36.42	355.784	37.58	(1.17)	3.1
1-Oct-05	396.567	40.86	395.464	39.68	1.18	(3.0)
1-Jan-06	484.195	87.63	484.973	89.51	(1.88)	2.1
1-Apr-06	399.582	84.61	396.467	88.51	(3.89)	4.4

*** No gas supply commodity change.**

e) If c) is agreed to, does Energy Probe agree that the percentage reduction in volatility on this basis has been much greater than plus or minus 1%?

Ontario Energy Board
FILE No. EB-2006-0034
EXHIBIT No. K2.1
DATE January 29, 2007.
08/99

Impact of Risk Management on the Price Consumers Pay:

Recent Experience of Enbridge Distribution Inc.

13. Table 1 below has been inserted to demonstrate to the Board that despite the very impressive results the Applicant has been able to portray in its Prefiled Evidence, wherein it compared the Standard Deviations of its Unhedged and Hedged Portfolios[2], the results for residential customers are: in a word, negligible; in a percentage, not more than 1% either positive or negative since the April 1, 2002 QRAM.

Table 1

Risk Management Impact on PGVA Reference Price

Date	PGVA Reference Price Without RM $/10^3 m^3$	PGVA Reference Price WITH RM $/10^3 m^3$	Price Impact of Risk Management on PGVA Reference Price	Resulting Price Difference $/10^3 m^3$	Resulting Price Impact: Expressed As a %
1-Jan-02	218.221	220.462	**Higher Price**	2.241	1.03%
1-Apr-02	188.783	193.532	**Higher Price**	4.749	2.52%
1-Jul-02	254.208	252.875	Lower Price	-1.333	-0.52%
1-Oct-02	237.963	237.963	**same**	none	none
1-Jan-03	259.115	259.519	**Higher Price**	0.404	0.16%
1-Apr-03	313.439	312.877	Lower Price	-0.562	-0.18%
1-Jul-03	313.439	312.877	Lower Price	-0.562	-0.18%
1-Oct-03	280.075	280.181	**Higher Price**	0.106	0.04%
1-Jan-04	262.337	263.197	**Higher Price**	0.86	0.33%
1-Apr-04	293.175	292.891	Lower Price	-0.284	-0.10%
1-Jul-04	334.344	332.911	Lower Price	-1.433	-0.43%
1-Oct-04	332.236	332.236	**same**	none	none
1-Jan-05	358.784	356.327	Lower Price	-2.457	-0.69%
1-Apr-05	318.199	319.285	**Higher Price**	1.086	0.34%
1-Jul-05	355.784	355.705	Lower Price	-0.079	-0.02%
1-Oct-05	395.464	396.567	**Higher Price**	1.103	0.28%
1-Jan-06	484.973	484.195	Lower Price	-0.778	-0.16%
1-Apr-06	396.467	399.582	**Higher Price**	3.115	0.79%
1-Jul-06	377.896	381.692	**Higher Price**	3.796	1.00%
1-Oct-06	377.896	381.692	**Higher Price**	3.796	1.00%

[2] Exhibit D1/Tab 4/Sched. 3, p. 6, Table 1

K2.2

Some of these stakeholders expressed the belief that unbundling is an integral element of facilitating competition, because, with unbundling, the market could provide these services to customers. This situation would increase customer choice by enabling customers to purchase the service or services that best suit their needs. Also, unbundling would ensure that the appropriate costs are included in the supply and delivery services and, as a result, customers could accurately compare costs between the different options in the marketplace.

The Board's Conclusions

Cost Allocation

The Board believes that the regulated gas supply option must be structured in a way that facilitates competition. The integrated nature of the supply and distribution services potentially makes the comparison between the regulated supply option and competitive supply options unbalanced. The current regulated gas supply costs include the cost of the commodity and limited overhead costs (such as risk management activities). Other overhead costs associated with the purchase, scheduling and management of gas supply and customer care costs are recovered through the distribution charges. Competitive supplier commodity charges reflect the overhead costs of sourcing, purchase and management of the gas function, including return. Therefore, questions are continually raised with the Board about whether distribution rates include supply costs and whether the rates for the regulated supply option hinder a viably competitive market where customers make decisions based on price.

In the Board's view, the pricing of the regulated gas supply option should minimize the potential for cross-subsidization between utility supply rates and distribution rates. The Board is not convinced one way or the other yet on the question of whether the current rates and/or rate structures contain cross-subsidies. It is of the view that the issue should be examined in a generic cost allocation hearing to determine the issue conclusively. The majority of stakeholders support this approach.

The Board will hold a generic cost allocation hearing.

Further Unbundling

Some stakeholders advocated further unbundling to ensure transparency and to facilitate customer choice. These stakeholders clearly identified a set of discrete services for the regulated gas supply option and a separate set of discrete services related to the distribution function, as follows:

- delivery services: transportation and delivery of gas, including seasonal and peak load balancing of gas to end-use locations; emergency response and repair services
- supply services: purchase and sale of the gas commodity; price risk-management of gas commodity; customer care (which includes billing costs); annual (or three-point) load balancing

The Board believes it is necessary to make a clear distinction between the services provided as part of the regulated supply function and the services provided by the distribution function, and to consider unbundling these services to a greater extent. The Board is not convinced that further unbundling will jeopardize the utilities' ability to provide load balancing and other services to customers. Rather, the Board believes that further unbundling of utility services can bring the following significant benefits:

- improve market efficiency for all customers by increasing price transparency
- facilitate competition by moving the regulated gas supply option and competitive options towards a level playing field

The Board also believes that there is merit in moving towards policies that are consistent between utilities. At present, the load balancing policies of the two largest utilities differ – Enbridge has an annual obligation, while Union has a three-point obligation.[20] The Board will examine the issue of harmonizing the load balancing obligations between utilities in the generic cost allocation proceeding.

[20] In Union's latest rate case, RP-2003-0063, Union was asked by the Board to file a report regarding load balancing obligations and the regulated gas supply.

The Board will not go beyond unbundling to pursue functional separation at this time. While some stakeholders were of the view that the synergies between the supply and distribution functions underpin the utilities' ability to provide certain services, the Board does not agree that the integration of functions is absolutely necessary. The utilities could act as system operators and continue to provide their current services without having an integrated customer supply portfolio. However, the Board does not intend to pursue functional or structural separation of the supply and distribution functions. Further analysis is necessary to ensure that the benefits of such a change exceed the costs, and the Board does not consider this issue to be a priority at this time.

The Board will examine the issues related to further unbundling as part of the generic cost allocation hearing. This process will incorporate the work already under way on this topic.

The Pricing Mechanism

Stakeholders' Views

Most stakeholders expressed the view that there should be greater standardization of the QRAM process across utilities and that the QRAM should be more formulaic. Both Union and Enbridge expressed interest in further harmonizing the QRAM process, and Enbridge expressed the belief that consistency could be enhanced.

However, stakeholders expressed a variety of views about the pricing structure of the regulated gas supply option. Some stakeholders said that the existing quarterly revisions are appropriate, while others suggested that monthly revisions would better reflect the true cost of gas. The residential customer groups and the utilities supported quarterly price updates. The residential customer groups argued that quarterly price updates contribute to price stability, while the utilities said that quarterly updates help strike the correct balance between the desire for accurate price signals and the desire for reduced price volatility.

On the other hand, most of the marketers believed that the price should be revised monthly, to more accurately reflect gas price volatility and to reduce the PGVA and associated carrying costs. One stakeholder expressed the belief that a quarterly adjustment dampened the daily and monthly price fluctuations. This dampening reduced the difference between the marketers' fixed-price options and the regulated gas supply option, and possibly created a barrier to entry of new competitors into the market.

In terms of pricing, there was some support among stakeholders, including Union and Enbridge, for a regulated-utility, fixed-price, one-year contract offer to customers. However, the majority of stakeholders said that the utilities should not have the flexibility to provide fixed-term, fixed-price gas contracts. In particular, stakeholders argued that a fixed-term, fixed-price offer could:

- impede customer mobility;
- create a vested interest for utilities to maintain a minimum number of customers;
- create barriers to entry for new competitors; and
- compete directly with marketers.

Some support also existed for a spot price pass-through, to eliminate the utilities' risk-management activities and to accurately reflect the market price of gas.

The Board's Conclusions

In determining the appropriate pricing structure for regulated gas supply, the Board must consider the trade-off between a price signal that accurately reflects market prices and price stability. The current pricing process, whereby the price is set every three months on the basis of a 12-month price forecast, represents a balance between market-price signals and price stability. Therefore, from one perspective, the regulated gas supply price could be said to reflect a rolling one-year price.

The Board needs to consider whether the current balance between price signals and price stability is appropriate. In particular, it needs to address two key concerns:

- Is a 12-month price outlook appropriate as the basis for pricing the regulated gas supply option?
- Is the frequency of the price adjustment appropriate?

On the first issue, it may be appropriate for the price to reflect some other level of variation. In other words, instead of reflecting a rolling one-year price, the price could reflect a different time period. The question is, over what time period should the price outlook be based? The Board is not of the view that a spot price pass-through would be appropriate, because of the potential for volatility that would result. On the other hand, a reflection of seasonal price fluctuations could strike a reasonable balance among market price signals, administrative simplicity and customer acceptance. The Board would also need to consider the impact of such a change on the PGVA.

On the second issue, the Board recognizes the link between the utilities' actual procurement costs and the price set through the QRAM process. The utilities acquire supply in the marketplace primarily through monthly indexed contracts. The difference between the actual procurement costs and the price set through the QRAM process is collected in the PGVA. The amount in the PGVA is then recovered from customers. Customers, therefore, receive a supply that is priced monthly, although the price they see is smoothed over a specific time frame. At this time, the Board sees no compelling reason to depart from a quarterly price adjustment. However, if the time period of the price outlook were redefined, then the frequency of the price adjustment would need to be re-examined.

The Board believes that the QRAM price should be a transparent benchmark that reflects market prices, and, therefore, the methodology for calculating this price should be similar for all utilities. The market needs an accurate and consistent price signal, most stakeholders agree. Therefore, the Board believes, the method for determining the reference prices should be formulaic and consistent and, similarly, the methods for determining the PGVA and for disposing of PGVA balances should also be formulaic and consistent.

The Board will develop guidelines for the standardization of the quarterly rate adjustment mechanism, with the above objectives in mind. As part of this activity, the Board will consult in more detail on the underlying pricing that should be incorporated.

With respect to whether utilities should be able to offer fixed-term, fixed-price contracts, the Board concludes that it would not be appropriate at this time. The regulated gas supply option should be seen as a default supply – a no-written-contract, no-obligation, market-priced choice – where the mobility of the customer is essential. The Board believes that introducing a utility-provided fixed-term, fixed-price contract offer at this time would present two risks. First, the fixed-term aspect could reduce the utility's ability to ensure full customer mobility. Second, the fixed-price aspect would compete with the product offered by the retail marketers. It would move the regulated supply away from being a default supply, and result in more direct competition between the utility and competitive suppliers. A fixed-term, fixed-price contract offer would require substantial additional regulatory oversight related to the underlying contracting, the customer-utility interface and the allocation of risk. The Board does not believe that this is the appropriate direction to take, and most stakeholders shared this view.

The Board believes that a utility-provided fixed-term, fixed-price contract offer is inappropriate at this time.

Long-Term Supply and Transportation Contracts

Stakeholders' Views

Many of the stakeholders (including customers, upstream players and utilities) asserted that the regulated gas supply is implicitly used to underpin future infrastructure development in the natural gas market. Some emphasized the importance of the utilities' creditworthiness, noting that utilities are among the few parties able to enter into the long-term contracts needed for infrastructure development. Views on the appropriate

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Risk Management Impact on WACOG & PGVA

Union Gas

	Alberta Border Reference Price			PGVA Activity			Risk Management Impact on PGVA Clearing		
Effective Date	Alberta Border Approved WACOG (Cdn $ / GJ) (A)	Alberta Border Approved WACOG Excluding Forecast Risk Management (Cdn $ / GJ) (B)	Forecast RM vs No RM (A vs B)	Actual PGVA Deferral Activity ($millions) (C)	PGVA Deferral Activity if No Risk Management ($millions) (D)	Actual Versus No Risk Management (C vs D)	Rate Rider to Clear PGVA Activity (cents / m^3) (E)	Rate Rider to Clear PGVA Activity if no RM (cents / m^3) (F)	Actual Versus No Risk Management (E vs F)
Jan-03	$ 4.95	$ 4.95	0%	$ 50.5	$ 50.0	1%	2.0	1.9	5%
Mar-03	$ 5.82	$ 5.81	0%	$ 66.1	$ 110.4	-40%	2.6	4.3	-40%
May-03	$ 6.45	$ 6.43	0%	$ 3.2	$ 1.2	163%	0.1	0.0	0%
Jul-03	$ 6.67	$ 6.58	1%	$ 10.2	$ 14.7	-30%	-0.4	-0.6	-33%
Oct-03	$ 5.82	$ 5.50	5%	$ 8.6	$ 15.5	-44%	-0.3	-0.6	-50%
Jan-04	$ 5.48	$ 5.34	3%	$ 35.7	$ 28.6	25%	1.3	1.0	30%
Apr-04	$ 6.32	$ 6.19	2%	$ 6.7	$ 9.1	-27%	0.2	0.3	-33%
Jul-04	$ 7.26	$ 7.19	1%	$ 27.8	$ 27.5	1%	-1.0	-1.0	0%
Oct-04	$ 7.37	$ 7.20	2%	$ 8.2	$ 5.7	42%	-0.3	-0.2	50%
Jan-05	$ 7.81	$ 7.87	-1%	$ 31.8	$ 39.6	-20%	-1.1	-1.3	-15%
Apr-05	$ 7.18	$ 6.98	3%	$ 1.3	$ 0.0	100%	0.0	0.0	0%
Jul-05	$ 8.01	$ 7.83	2%	$ 5.1	$ 9.8	-48%	0.2	0.3	-33%
Oct-05	$ 9.08	$ 8.91	2%	$ 72.5	$ 86.9	-17%	2.5	3.0	-17%
Jan-06	$ 10.86	$ 10.86	0%	$ 45.3	$ 49.6	-9%	-1.6	-1.7	-6%
Total				$ 372.8	$ 448.5	-17%			
Average	$ 7.08	$ 6.98	1.5%				Abs Value Avg 1.0	Abs Value Avg 1.2	-16%
Standard Deviation	$ 1.5	$ 1.5	-1%	$ 23.4	$ 31.8	-26%	1.3	1.6	-21%

Conclusions:

(1) Risk Management Forecast has minimal impact on the setting of Union's WACOG.

(2) Over the long term, actual Risk Management costs(credits) has minimal impact on Union's Cost of Gas but does reduce the monthly volatility.

(3) Union's actual Risk Management has reduced the deferral activity and the subsequent disposition required to clear PGVA deferral accounts through the QRAM process.

[redacted]

Response to Energy Probe's Notice of Questions, May 25, 2006

Union Gas

Alberta Border Reference Price / Risk Management Impact on PGVA Clearing

	Alberta Border Reference Price			Risk Management Impact on PGVA Clearing			
Effective Date	Alberta Border Approved WACOG (Cdn cents / m^3)	Alberta Border Approved WACOG Excluding Forecast Risk Management (Cdn cents / m^3)	Forecast RM vs No RM	Rate Rider to Clear PGVA Activity (cents / m^3)	Rate Rider to Clear PGVA Activity if no RM (cents / m^3)	Difference Between RM and No RM (cents / m^3)	(E-F) as % of Average Cost of Gas
	(A)	(B)	(A vs B)	(E)	(F)	(E-F)	(G)
Jan-03	18.6	18.6	0%	2.0	1.9	0.1	0%
Mar-03	21.9	21.9	0%	2.6	4.3	-1.7	-7%
May-03	24.3	24.2	0%	0.1	0.0	0.1	0%
Jul-03	25.1	24.8	1%	-0.4	-0.6	-0.2	-1%
Oct-03	21.9	20.7	5%	-0.3	-0.6	-0.3	-1%
Jan-04	20.6	20.1	3%	1.3	1.0	0.3	1%
Apr-04	23.8	23.3	2%	0.2	0.3	-0.1	0%
Jul-04	27.3	27.1	1%	-1.0	-1.0	0.0	0%
Oct-04	27.8	27.1	2%	-0.3	-0.2	0.1	0%
Jan-05	29.4	29.6	-1%	-1.1	-1.3	-0.2	-1%
Apr-05	27.0	26.3	3%	0.0	0.0	0.0	0%
Jul-05	30.2	29.5	2%	0.2	0.3	-0.1	0%
Oct-05	34.2	33.5	2%	2.5	3.0	-0.5	-2%
Jan-06	40.9	40.9	0%	-1.6	-1.7	-0.1	0%
Total							
Average	**26.6**	**26.3**	**1.5%**	Abs Value Avg **1.0**	Abs Value Avg **1.2**		**-1%**
Standard Deviation	**5.6**	**5.7**	**-1%**	**1.3**	**1.6**		

Scurrel M1.19

Risk Management Program - Impact 1998-2005

Union Gas

Volatility (Standard Deviation)	1998	1999	2000	2001	2002	2003	2004	2005	1998-2005 Total
Union's Monthly Actual Cost of Gas (Cdn$/GJ)	$ 0.31	$ 0.34	$ 1.16	$ 1.21	$ 0.66	$ 0.57	$ 0.68	$ 2.06	
% of avg annual price	8%	8%	24%	18%	15%	9%	10%	23%	
Market (NYMEX Monthly Settles) (US$/mmbtu)	$ 0.20	$ 0.44	$ 1.18	$ 2.26	$ 0.65	$ 1.26	$ 0.90	$ 2.99	
% of avg annual price	9%	19%	30%	53%	20%	23%	15%	35%	
Union's Volatility Reduction Versus Market	**-15%**	**-57%**	**-20%**	**-67%**	**-26%**	**-62%**	**-34%**	**-32%**	**-39%**

Mark to Market (millions Cdn $)	1998	1999	2000	2001	2002	2003	2004	2005	1998-2005 Total
Actual Mark to Market Credits(Costs)	$ (3.5)	$ 0.1	$ 41.6	$ (65.5)	$ (19.9)	$ 30.4	$ (1.9)	$ 9.9	**$ (8.7)**
% of Annual Commodity Costs	**0%**	**0%**	**-6%**	**8%**	**6%**	**-4%**	**0%**	**-1%**	**0%**

Union's Avg Annual Cost of Gas (Cdn $ / GJ)	1998	1999	2000	2001	2002	2003	2004	2005	1998-2005 Average
Actual With Risk Management Impact	$ 3.95	$ 4.11	$ 4.77	$ 6.85	$ 4.39	$ 6.40	$ 6.96	$ 8.78	$ 5.78
Assumes No Risk Management	$ 3.94	$ 4.11	$ 5.06	$ 6.33	$ 4.13	$ 6.69	$ 6.94	$ 8.87	$ 5.76
% of Commodity Costs	**0%**	**0%**	**-6%**	**8%**	**6%**	**-4%**	**0%**	**-1%**	**0%**

Exhibit K.24

EB-2006-0034

Cross-Examination Materials

On

Risk Management

Energy Probe Research Foundation

January, 2007

5. RISK MANAGEMENT

5.1 BACKGROUND

5.1.1 The role of and nature of the risk management program has been the subject of continuous revision and evolution. The very purpose of the program, as well as the rules governing its execution, has changed markedly over the last few years. As part of this process, Enbridge was required to procure expert advice and to present the resulting report to the Board. Enbridge retained RiskAdvisory, a recognized expert in the design and implementation of risk management activities at utilities. The resulting RiskAdvisory report was filed in the RP-2003-0203 proceeding and contained 16 recommendations. In that proceeding, Enbridge addressed seven of the RiskAdvisory recommendations and advanced three of its own proposals for changes in the program. In the current proceeding, Enbridge brought forward its plans for implementing the remaining nine recommendations.

5.1.2 Specifically, Enbridge is seeking Board approval for two aspects of the risk management program:

- an increase in the price volatility tolerance band from the current $35 level to $75 level, based on the findings of the Customer Threshold for Gas Supply Volatility Study; and
- the closing to rate base of approximately $930,000 related to the transition of the program from a spreadsheet format to a database format.

5.2 THE CUSTOMER THRESHOLD FOR GAS SUPPLY VOLATILITY STUDY

5.2.1 In RP-2003-0203, Enbridge indicated the need to survey its customers in order to better understand their sensitivity to price volatility and to use these findings to update the $35 price volatility tolerance level identified in the surveys undertaken in 1994 and 1995.

Enbridge commissioned Ipsos-Reid to conduct the survey and identified the following specific objectives for the research:

- Assess customers' level of knowledge, understanding and expectations about gas pricing and the Company's role in the process.
- Determine customers' expectations about gas prices and their sensitivity to price volatility.
- Understand customers' preferences for risk management strategies in general and under different market conditions.
- Determine customers' preferences for the frequency of bill adjustments.

5.2.2 According to Enbridge, the results of the survey indicated that customers are tolerant of fluctuations of less than $75 in the commodity portion of their annual bill. A significant majority of customers indicated a preference that price volatility risk be managed. Customers were also asked about their preference for risk management strategies. Enbridge reported that while under a variety of scenarios a vast majority of customers indicated a desire for some form of hedging activity, they were generally evenly divided in choosing among the alternatives.

5.2.3 Given the survey results, Enbridge requested Board approval for an increase in the price volatility tolerance band from the current $35 to $75. It further stated that there would be no change in the hedging methodology employed, which was previously approved in RP-2003-0203. The proposed change in the volatility tolerance band has the effect of materially reducing the amount of hedging activity authorized and undertaken by the program.

5.2.4 While some intervenors expressed concern with the survey design, they supported increasing the tolerance level on the grounds that it may lessen the administrative burden of the program. It was also suggested that the sharp increase in commodity prices since the implementation of the $35 level justified a change. Indeed, some intervenors argued

3

that the level of the tolerance band should be higher than that sought by the Company, given the higher prevailing commodity price level.

5.3 BOARD FINDINGS

5.3.1 The Board notes that there was no opposition to the raising of the threshold per se, and approves the changes applied for with respect to the adoption of the $75 action level. The issues raised by those intervenors which oppose the program in whole are addressed in the next section.

5.4 THE TRANSITION OF THE PROGRAM TO DATABASE FORMAT

5.4.1 Enbridge submitted that since the risk management database will be placed in service by the end of 2005, it is appropriate to close all amounts spent on the project to rate base by the end of the year. Enbridge noted that the cost to convert the functionality of the model from a spreadsheet to a database format is estimated at $930,000.

5.4.2 Enbridge's proposal to include these costs in rate base led to the examination of the purpose and effectiveness of the overall risk management program and concerns with respect to duplication of functionality within the context of the Quarterly Rate Adjustment Mechanism ("QRAM"), the Purchase Gas Variance Account ("PGVA") and the equal billing program.

5.4.3 Some intervenors argued for the discontinuation of the risk management program and argued that it would be inappropriate to include the $930,000 in the 2006 opening balance for rate base. Enbridge argued that the issue was beyond the scope of this proceeding, insofar as the termination of the program did not appear on the Issues List, nor did any intervenor take the appropriate steps to include it on the Issues List.

5.5 BOARD FINDINGS

5.5.1 The Board has never previously focused its attention on the specific expenditures made to transition the program to the proposed database format. Enbridge made this transition without specific Board approval or direction. Its evidence that program administration had become unwieldy and unnecessarily complex was not challenged by those intervenors who opposed the Company's proposal. They directed their attention to the fundamental utility and advisability of the program as a whole.

5.5.2 Some intervenors strongly supported the risk management program, seeing it as a measure of protection, especially for low-income consumers, whose tolerance for price volatility was suggested to be less than that of other customer groups. They argued that many consumers, particularly low-income consumers, are vulnerable to steep price fluctuations, especially in an environment where there seems to be a generally upward tendency in commodity prices.

5.5.3 On the other hand, others are strongly opposed to the program, and regard the expansion of the actionable volatility level to $75 as tinkering with a program that should be eliminated.

5.5.4 Energy Probe, supported by CME, IGUA and the retail gas marketers, opposed the continuation of the risk management program. Energy Probe presented evidence by Mr. Adams, its Executive Director, which focused on two points:

- Given that the program is designed merely to smooth the impacts of market prices of the commodity, and not to lower them, it is of no real value to consumers. The "real" price will always emerge sooner or later, and consumers are not served by the illusion that the market price is actually being affected by the hedging activities of the utility.

- There is value in ensuring that consumers have direct experience of the actual price of the commodity that they consume. Any softening of that experience through hedging activities obscures the market price signal. Consumers are best served when they receive an accurate and un-hedged price signal from the market because they can vary consumption according to such signals.

5.5.5 This last concern motivated the retail gas marketers to oppose the program and any increased spending associated with it. In their view, the smoothing of price volatility sends inaccurate signals to the consumer, and improperly undermines the attraction of their fixed-price offerings in the marketplace. The dominant position of Enbridge which derives from its standard service supply monopoly is, in their view, exacerbated by the smoothing of commodity price fluctuations. They argued that the transparency of the price is an important element in their competitive environment. They contended that they are operating at a competitive disadvantage to the extent that the risk management program blurs that transparency.

5.5.6 An important part of the background to this issue is the existence of the Quarterly Price Adjustment Mechanism ("QRAM"). Some form of QRAM is applied to all privately held gas distribution utilities in Ontario, including Enbridge. While there are important differences in the respective methodologies, they share the effect of moderating and smoothing anticipated commodity price fluctuations. As part of the Natural Gas Forum, the Board expects to consider the standardization of QRAM methodology across all utilities.

5.5.7 As part of the QRAM process, the Board also provides for the maintenance of and disposal of the Purchased Gas Variance Account. This account captures the difference between the Company's projected cost of system gas and the actual cost. Its clearance also has the effect of smoothing commodity price fluctuations, insofar as the clearance of the account is distant in time from market purchases.

5.5.8 Finally, the Board notes the availability of equal billing plans for most residential customers. Such plans also have inherent smoothing effects, given that customers pay an averaged monthly amount which is subject to a true-up at or near the year end.

5.5.9 All of which is to say that in its implementation of the QRAM, its approach to the PGVA and the existence of equal billing plans, the Board accepts the principle that some form of price smoothing is an appropriate consumer protection measure. It is also important to emphasize that no matter what smoothing techniques are employed, the most that can be hoped for is a reduction in volatility, not an overall reduction in the price of the commodity over time. Subject to possible generational anomalies, consumers, both large and small, will pay the full burden of the market price for the commodity, sooner or later.

5.5.10 The question that remains is the extent to which Enbridge's risk management program is redundant or represents a useful and cost effective tool to reduce consumer price volatility in a fair and reasonable way. The Company provided evidence which seemed to show that its hedging activity smoothed its experience of commodity price fluctuations. No evidence has been provided that demonstrates whether the hedging activity had a material effect on the volatility experienced by customers, given the effects of QRAM, the PGVA, and equal billing programs over the same period. If hedging activity has no material effect on the volatility experienced by customers, then it may be that the risk management program is not required.

5.5.11 Accordingly, the Board directs Enbridge to prepare for consideration in its next rates case evidence which demonstrates the extent to which the Company's hedging activities in 2003, 2004, and 2005 would have resulted in reductions in volatility for its customers, had it applied the proposed $75 action level.

5.5.12 Enbridge asserted that the continuation of the program is not an issue in this proceeding, and that the intervenors who argued for its elimination in this case are seeking an outcome that is simply beyond the Board's scope. This point of view was supported by several intervenors that support the program, if not the specific changes sought by the Company.

5.5.13 While it is unnecessary to decide this point for the purposes of this Decision, given the Board's disposition of the issue in this case, the Board considers it appropriate to address the underlying proposition. The Board considers that where convincing evidence is presented which leads to a compelling conclusion that a program does not provide value to ratepayers, it is always open to the Board to disallow any further spending on the program, whether or not the issue falls within the four corners of an issue on the Issues List. The Board would clearly have a duty to exercise this discretion only in the most compelling case and never without offering the Company an appropriate opportunity to rebut the evidence supporting the termination of the program. The overriding principle is that in a rates case the Board always retains jurisdiction to make whatever order is necessary to establish just and reasonable rates. Requiring ratepayers to pay for operations that have been demonstrated to be without value to ratepayers is unreasonable.

5.5.14 The Board notes that Energy Probe's evidence was subject to all of the normal procedures. The Company cannot assert that it had no notice of, or was unduly prejudiced by the Energy Probe evidence. If the Company intended to insist that the termination of the program was out of scope, it should have done so when first presented with the Energy Probe evidence urging that outcome.

5.5.15 The Board will not order the discontinuation of the program for the Test Year. The Board is, however, concerned about the fundamental appropriateness of the program, and accordingly has directed the Company to develop evidence respecting its effects, as detailed above. In the interim, pending the Board's consideration of that evidence in the next rates case, the sums expended to upgrade the Program to a database format will not be released to rate base. Instead, the relevant sum, thought to be approximately $930,000, shall be placed in a deferral account exclusive to this purpose. The deferral account will be disposed of according to the Board's finding in the next rates case.

average customer could understand.[160] In fact, notwithstanding that the questions in the survey related to risk management instruments did not mention risk management terminology (such as caps, collars and swaps), they were nonetheless able to convey concepts such that the average consumer could understand and comment.[161] In short, the Company believes that the customer survey, which was undertaken in accordance with the Board's decision in RP-2003-0203, provides a valuable and updated perspective on the $35 price volatility tolerance level identified in the surveys undertaken in 1994 and 1995 and is more relevant than earlier studies that were undertaken in different market environments with much lower gas prices.[162]

The results of the customer survey indicate that the Company's emphasis on reducing price volatility and the approach to managing that price volatility is supported by its customers. Additionally, customers have indicated their acceptance to have the commodity portion of their annual natural gas bill fluctuate by a maximum of $75. Given the survey results, the Company requests Board approval to increase the price volatility tolerance band from the current $35 to $75.[163]

C. Evidence of Energy Probe

On June 23, 2005, Energy Probe submitted evidence in this proceeding titled "Risk Managed System Gas: The Case Against", authored by Tom Adams.[164] CCC's counsel described it as a "root and branch critique of the value of the risk management program at Enbridge".[165] Mr. Adams confirmed on cross-examination that he is not an expert on risk management, nor on customer survey design or implementation, which are among the main topics that he addresses in his paper.[166]

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[160] 5 Tr. 120-121; Ex. I-3-17

[161] Ex A3-3-1 Attachment, pp 41-45 – Questions 14 to 19

[162] 5 Tr. 115

[163] Ex. A3-3-1, p 9

[164] Ex. L8-2

[165] 5 Tr. 65

[166] 38 Tr. 119

In short, Energy Probe's position paper urges the Board to order the discontinuance of the Company's Risk Management Program. This is not on the Issues List for this proceeding, nor did Energy Probe take any steps to have that issue included on the Issues List, either at Issues Day or subsequently. As Mr. Adams acknowledged on cross-examination, the listed issues for this proceeding relate to the implementation of the RiskAdvisory report and the customer survey.[167] According to Mr. Adams, the link between the Issues List and Energy Probe's position is that "[t]he issues list contains with it – within it an assumption that the utility will continue its risk management program".[168] Interestingly, however, as Mr. Adams stated in his testimony, Energy Probe did not challenge the existence or prudence of the Company's risk management program in the F2005 rate case, when there was a more wholesale evaluation of the risk management program than in this case, because "[t]he argument as to the discontinuance of the plan we believe to have been off the issues list in that proceeding".[169] Presumably, however, the same assumption that the Company would continue its risk management program was also part of the Company's F2005 rate case. Given that the question of whether the Company should continue its risk management program is not an issue in this proceeding, the Company urges that little if any weight should be given to Energy Probe's evidence.

If the question of whether the Company ought to continue its risk management program is not at issue in this proceeding, then Energy Probe is actually supportive of the relief sought by the Company. This can be seen in the final sentence of Energy Probe's submission which reads:

> In the alternative, if the Board is not moved to order the discontinuance of risk management entirely, the threshold target for the minimum PGVA balance be should raised substantially, at least to $75 per customer, although $100 would be better and $200 better still.[170]

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[167] 38 Tr. 165

[168] *Ibid*

[169] 38 Tr. 123; see also 38 Tr. 159

[170] Ex. L8-2, p 12

In cross-examination, Mr. Adams confirmed that Energy Probe does support raising the threshold.[171]

Notwithstanding the fact that Energy Probe's position paper does not appear to bear upon matters at issue in this proceeding, the Company has several comments to make in response.

First, in respect of the overall argument by Energy Probe that the Risk Management Program should be discontinued, the Company has the following responses: (i) the Board has recently confirmed in both the RP-2003-0203 and RP-2003-0063 (Union Gas F2004 Rates Case) Decisions that gas commodity risk management programs are beneficial[172]; (ii) Energy Probe does not rely on any change in circumstances from those existing at the time of recent Board decisions in support of its position that risk management should now be discontinued[173]; (iii) every gas utility in Canada, except for one, has a commodity risk management program[174]; and (iv) in contrast to the Company's survey results, Energy Probe presents no recent evidence that customers do not want commodity risk management.[175] To the contrary, Energy Probe acknowledges that "all customers would like to have no price volatility"[176] and that there are consumer groups who support the continuation of risk management.[177]

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[171] 38 Tr. 152 and 166-167

[172] Ex. K38.2, Tabs 2 and 3: RP-2003-0203, Decision with Reasons, November 1, 2004, para. 4.3.4; and RP-2003-0063, Decision with Reasons, March 18, 2004, p 17

[173] 38 Tr. 161-163: while Mr. Adams asserts that it is only in this case that the Company is making it clear that "customers should not anticipate sustained benefits, in terms of lower prices, over time", the fact is that the Company made this clear in the F2005 case, as seen in para. 4.3.8 of the Board's decision which approves the proposal to make reducing price volatility the primary objective of the Company's risk management program (as opposed to a joint objective along with benefiting and profiting from price declines)

[174] 38 Tr. 121 and 171

[175] 38 Tr. 169

[176] 38 Tr. 155

[177] 38 Tr 172

Second, the following testimony by Mr. Rubino answers Energy Probe's suggestion that "risk management provides no sustained value to ratepayers"[178]:

> We disagree strongly with that statement. Our view is that, given that customers have indicated, through this survey, through the survey that was done ten years ago, that they have a desire for the company to take actions to mitigate some of their exposure to volatility; the customers value the actions that the company is taking. And an ongoing risk-management program provides that sustained value. Whether it's a pure economic value, in terms of, you know, the program winning or losing in a given year, the sustained value is that there has been mitigation of volatility, which is what customers have indicated they are looking for the company to do.[179]

Finally, in response to the suggestion that ratepayers are burdened by the costs of the Company's Risk Management Program, the Company reiterates that the costs are minimal. Significantly, however, the benefits are substantial. As seen in the response to Undertaking J5.8, over the years from 2001 to 2004, the Company's Risk Management Program reduced price volatility of the Company's gas purchasing by an average of 61%.[180] It defies belief to assert, as Mr. Adams does, that none of this decreased volatility is felt by system gas customers.[181] Moreover, while this is not the goal of the Company's Risk Management Program, in the years from 1996 to 2004, the overall reduction in gas purchase costs as a result of the Program, which is directly passed on to customers, was $59.1 million.[182] This certainly does not represent a cost burden to ratepayers.

D. Conclusion

The Company respectfully submits that, based upon its prefiled evidence, including the customer survey, and its testimony in this proceeding, it has provided a solid evidentiary basis for Board approval to increase the price volatility tolerance band from the current $35 to $75.

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[178] Ex. L-8-2, p 11

[179] 5 Tr. 71-72

[180] Ex. J5.8, which attaches and updates Ex. I-1-18 from the RP-2002-0203 proceeding; see also 5 Tr. 67 and 38 Tr. 146-148

[181] 38 Tr. 146-148

[182] Ex. J5.6

Given the nature of the issues actually before the Board in respect of risk management, and in particular the fact that the potential discontinuance of risk management activities is not at issue in this proceeding, the Company respectfully submits that no relief ought to be granted in response to Energy Probe's evidence and submissions.

7. RATE BASE

Rate Base is the subject matter of Issues 8.1 through 8.4 of the Issues List, which are specifically identified as follows:

> 8.1 Capital Budget for the 2006 Test Year including capitalized O&M expenses
>
> 8.2 Information Technology Capital Budget including Energy Transaction, Reporting, Accounting and Contracting (EnTrac), and Meter Management and Large Volume Meter Data Processing (EnMar) projects
>
> 8.3 Appropriateness of the capital budget "placeholder" for power generation project RFPs
>
> 8.4 Appropriateness of the capital budget for System Improvements and upgrades, including the budget increases in system expansion and reinforcement projects and the Accelerated Bare Steel and Cast Iron Replacement Program

None of these issues were resolved during the Settlement Conference. As a result, together with its extensive prefiled evidence, the Company also provided three witness panels during the hearing to speak to different aspects of this broad subject matter: a *policy panel* (including the Company's President) to speak to the underlying rationale of the Test Year capital budget; a *customer attachment-related panel* to address system expansion and customer attachments (and in that context, the issues around prospective gas-fired electricity generation customers); and a *system reinforcement-related panel* to address the remainder of the capital and rate base issues (including the information technology capital budget and the appropriateness of the Company's reinforcement projects, and accelerated bare steel and cast iron replacement program).

you want to ask to help the customers get their -- get a frame of reference, in terms of what's being talked about. But in terms of trying to do a direct comparison of a survey that was done ten years ago, and try to establish historical trends, that wasn't one of our objectives.

MR. ADAMS: In the -- the results of this survey in 1995, in response to the clear question "do you want the lowest price, as opposed to a higher, but stable, price" -- the response to that question, on a scale of 1 through 7, was that 73 percent - and I'm reading from the conclusions of the Compass study, page 12 - on a scale of 1 through 7, 73 percent of the residential, and 70 percent of the industrial, commercial and apartment customers, responded believing paying the lowest price is important.

Of these, 35 percent, in each group, gave a score of 7, the highest score -- highest point. Among residential -- the residential sample, 11 percent are neutral, and 15 percent say it's not important compared to a higher, but stable, price.

I suggest to you that the only evidence that we have on the record before the Board as to customer views - specifically, on whether they want lowest price, as opposed to a higher, but stable - is the answer to that question that was asked in 1995.

Do you object to that observation?

MR. CHARLESON: Well, I think, again, looking back to the question from this survey that Mr. Rubino pointed to earlier, on page 29 of the evidence, it does provide, in my opinion, an updated view of that. While it's not an identical question, it gets to the same principles, the same concepts. And so, as a result, I would say that this is something that does provide an updated perspective on that, and is more current and more relevant than a ten-year-old survey, when we were operating in a much different market environment.

MR. RUBINO: The headline on that page 29 of the attachment, indicates:

> "'It is more important to maintain a steady price than to obtain the lowest price', more than 6 in 10 -- 60 percent small commercial customers, somewhat more than residential, 55%."

MR. ADAMS: I see the headline, but that's not -- the headline was not presented to the customer -- to the --

MR. RUBINO: No.

MR. ADAMS: -- participants in the survey.

MR. RUBINO: The question was -- in very small type at the bottom --

MR. ADAMS: Yes. And that question --nowhere does it indicate that the steady price is higher.

MR. CHARLESON: You're right.

MR. ADAMS: The conclusion in the 1995 study, in the paragraph on page 12, is as follows:

> "Hence, there is clear support by well over half the respondents in all segments for the concept of taking on the risk of higher prices by managing purchasing gas at floating prices in

order to gain the opportunity to achieve lower prices."

And that, really -- at the time, that was the objective of the program; would you agree, Mr. Rubino?

MR. RUBINO: That's correct. It was, at that time.

MR. ADAMS: The conclusion -- the final statement is:

"This is more important than average among residential respondents with lower incomes and women."

Then it goes on to say:

"There are not significant differences between groups of the ICA sample."

Just, specifically, with regard to this last conclusion, where the previous study identified low income groups and women -- the views of low-income individuals and women, separately, do I understand correctly that was not done in the Ipsos-Reid study?

MR. CHARLESON: There was some segmentation done within the study. However, the observations that we received, in terms of the reporting that was done for us by Ipsos-Reid, and the compilation of the report, didn't get into that degree of segmentation because, again, given that we were looking at something for a total customer base, we had responses that we believed, and that our research group indicated to us, were representative of the entire customer base. You know, it's our belief that we're trying to put in place a program, and put in place measures, that meet the needs of all customers, not targeted groups.

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MR. ADAMS: So is it fair to say that the only information we have in front of the Board, with respect to the views of low-income individuals, with respect to their desire for paying a premium to achieve price stability, is that they are among the least favourable to this, and that is lower than the 73 percent average amongst residential customers who are not in favour of paying the premium --

MR. CHARLESON: I'm not --

MR. ADAMS: -- is that fair?

MR. CHARLESON: No, I don't know if that is fair, because I don't follow what evidence you're pointing to, to reach that conclusion.

MR. ADAMS: From the 1995 study --

MR. CHARLESON: That's --

MR. ADAMS: -- the section I just read to you.

MR. CHARLESON: Yes, I would say that's the only information available within the record in this proceeding, but again, recognizing it's a ten-year-old study, and reiterating that our focus is on all customer groups, and not specific segments.

MR. ADAMS: Thank you. Now, with respect to direct-purchase customers surveyed, I looked in the methodology discussion, and did not find the survey attempted to confirm that the respondent to the survey matched the signature on the applicable marketer contract; is that a fair reading?

MR. CHARLESON: Yes, I would say that is a fair reading. And it may be difficult to assess, given that a large number of customers still don't realize they're on direct purchase --

MR. ADAMS: Right.

MR. CHARLESON: -- so they may not know who signed the contract.

MR. ADAMS: Right. It's -- apparently, 58 percent of your customers aren't sure whether -- 58 percent of the customers that are on direct purchase don't know that they're on direct purchase, according to the survey results?

MR. CHARLESON: That sounds about the right number.

MR. RUBINO: Subject to check.

MR. CHARLESON: And that's something that we have seen through, I think, through a few surveys we've done over the last couple of years. That number has been consistently around 60 percent.

MR. ADAMS: On the issue of including direct-purchase customers in the survey, I note that, in the Natural Gas Forum, EGD expressed the view that it ought to be permitted to maintain a critical mass of system-gas customers. Was that desire by your company one of the reasons why direct purchase-customers were included in the sample?

MR. CHARLESON: No, that didn't play a factor in our sampling, at all.

MR. ADAMS: The page that Mr. Rubino just turned us to, from the Ipsos-Reid study, page 29 --

MR. RUBINO: Yes?

MR. ADAMS: Specifically, with regard to --

MR. RUBINO: Yes.

MR. ADAMS: The system gas actual results, where 51 percent of the customers are in favour of steady versus 47 lowest and 2 percent don't know, is the result there statistically significant? Can we statistically determine that system gas actuals are in favour of steady, or not?

[Witness panel confers]

MR. RUBINO: Yes. The answer is yes. I made a point of asking our business and intelligence group -- sorry, research and business intelligence group, and then, in turn, them asking the Ipsos-Reid people, and they indicated that it was.

MR. ADAMS: That is statistically significant?

MR. RUBINO: Yes.

MR. ADAMS: I understood that the errors bounds in the study were 3 percent.

MR. RUBINO: Three-and-a-half.

MR. CHARLESON: Perhaps there is some confusion between statistically significant and statistically valid. So it is statistically valid sample, statistically valid sample size. In terms of significant, you're correct, there is a margin of error in the survey, I believe, of plus or minus 3 percent.

MR. ADAMS: Right.

MR. CHARLESON: So, again, to say that the majority of customers are -- of system gas actual customers are in favour of steady versus -- as compared to lowest, there is the potential that given the margin of error, that it overlaps.

MR. ADAMS: Yes, thank you. Just before I leave this area, one last question. I observed at several points indications of significant customer confusion, like, for example, a relatively small number of direct purchase customers knowing that they're on direct purchase.

In light of this indication that customers really don't have a deep understanding of how the gas markets are serving them, do you have any concerns about the reasonableness of asking customers about the relative preference for caps versus collars versus swaps? Caps and collars might sound like a clothing choice to most customers.

MR. CHARLESON: I think definitely we had concerns with how you go about asking customers about, you know, caps, collars, swaps, because it's -- again, even until I got responsibility in these areas, I would have been confused by that. But that was one of the key elements in designing the survey, was having the discussions with Ipsos-Reid and with risk advisory to try to craft questions in a manner that would put those instruments into terms that the average consumer would be able to relate to and to understand.

MR. RUBINO: Yes. And we spent -- I spent a considerable amount of time. It's question 14 in the survey, and it's repeated in response to CME Interrogatory Number 17 in this proceeding.

MR. ADAMS: Mm-hmm.

MR. RUBINO: I would suggest if you read through those, it doesn't really matter what they're called, swaps, caps or collars. It was the concept we were trying to get across, and, again, realizing it was a telephone survey in the evening, but we -- we believe that we succeeded in accurately describing conceptually what each of those three hedge instruments attempts to achieve.

MR. ADAMS: When we looked at the results that arose from asking their preferences with regard to the caps, collars or swaps, my reading of it is that the opinion appears to be fairly evenly split there.

MR. CHARLESON: Yes. That was our view, as well.

MR. RUBINO: It was our view, as well.

MR. ADAMS: So one possible explanation for this is simply that the customers are throwing darts at the answer and politely responding with, you know, something that they thought might entertain the survey questioner.

MR. CHARLESON: Or the possible other outcome is that they understood the question and they responded based on what their preference was.

MR. ADAMS: Right. So the same people that didn't know whether they were on system gas or direct purchase were providing a deeper understanding of financial hedging instruments; is your suggestion?

MR. CHARLESON: Yes, because, again, I think -- I don't want to get argumentative, but I think the -- for people to understand whether they're on system gas or direct purchase requires them to, one, either recall having entered into a contract, being -- paid particular attention to their bill to understand who their supply is based on what is indicated on their bill.

To have -- so that's not something top of mind, though. When I open my bill, I don't look to the middle to make sure that I am still getting the system gas rate or that I am still on system supply.

But hearing the question, it is put in terms that are, you know, very general and very generic in nature and very common terminology; doesn't require your having to recall, What did I see on my bill, or what did I -- or what did I sign up for at the door or online.

So I think there is a great difference, in terms of the ability or the -- for customers to respond appropriately to the questions.

MR. ADAMS: Okay. Thank you for that. I want to turn to the question of hedgible volumes, and the interrogatories I'm going to refer to are CME 14 and page 3 of VECC IR 28, part F, if you would.

MS. NOWINA: Is that part of your package, Mr. Adams?

MR. ADAMS: Unfortunately not. This is where I --

MS. NOWINA: Okay. Just give us a moment.

MR. ADAMS: -- was incomplete.

MR. CHARLESON: Sorry, the second one for VECC was 14?

MR. ADAMS: VECC 28, CME 14.

MR. CHARLESON: Okay.

MR. ADAMS: Now, I am really perplexed about how you calculate hedgible volumes, and I just want to get this cleared up.

If we -- if we look to CME 14, you have a calculation that you present there. It's lowest number degree days in the last ten years, multiplied by current use per degree day, multiplied by current number of customers, multiplied by the lower of -- the lowest level of participation in system gas in the last ten years or the company's view of system gas participation in the forecast period.

MR. RUBINO: That's correct.

MR. ADAMS: Okay. So that multiplies out to some very large number.

MR. RUBINO: Correct.

MR. ADAMS: Probably in the millions?

MR. RUBINO: This past year it was approximately 120 Bcf.

MR. ADAMS: Okay. Now, the one piece of it that I need some help with, how does -- how many customers are going to be on system gas next year?

MR. RUBINO: Well, there will be -- internally, we'll have an estimate of what that number will be, based on historical information.

MR. CHARLESON: Right now we look at that being, I'd say, somewhere between, say, 950,000 and just over a million, say, just -- right now, we're seeing it around 60 percent of our customers are on system gas.

MR. ADAMS: The fraction of customers on system gas bounces around; right?

MR. CHARLESON: It moves, but over the past number of years, and I think if you -- again, I'm trying to -- there's an interrogatory response where we provided --

MR. ADAMS: Energy Probe 95?

MR. CHARLESON: Ninety-five. So if we look at -- which is Exhibit I, tab 8, schedule 95. I think if you look back through there, what we've seen is, say, over the last seven years, other than, say, 2001 and 2002 when we saw the initial -- say, the price spike coming out of the winter, say, December 2000, the percentage of customers on system gas or the distribution between system gas and direct purchase has remained fairly stable.

So it's almost like we view those two years as an exception, and then it settled back into a relatively steady pattern and we're seeing that pattern continue.

So it will fluctuate, but I think it fluctuates within -- at this point, at least, within a relatively narrow band, recognizing that you may have a couple of years where there will be exceptions.

MR. ADAMS: Yes. So over the period of years shown here, which is eight years, of those years, five of them -- I'm sorry, six of those eight, it's around -- between 36 percent and 40 percent. But then, two of those years, it's over 45; right?

MR. CHARLESON: Yes, that's correct.

MR. ADAMS: And so you're saying that you're certain that next year, 2006, it will be at the -- around the figures that it's been in six of these eight years.

MR. CHARLESON: I can't say I'm certain. It --

nothing is certain. Given the price run-ups that we have seen over the past couple of months, we may see a similar response from customers to the direct-purchase markets that we saw back in 2000, 2001. You know, that remains to be seen.

But if we look at the formula, again, that's used within -- that's identified in the CME response, it would be the lowest level of participation in system gas in the last ten years. Or, our view on system -- so if our view on participation in system-gas was that it was going to stay where if is today, around 60 percent, the number that we would end up using would be the 52 percent --

MR. RUBINO: It's the lower of --

MR. CHARLESON: -- the lower of. So the 2002 number, where we had 52.6 percent on system gas, that would be the lower number that gets used.

MR. RUBINO: It's intentionally conservative. The purpose of this calculation is to ensure that the company is not over-hedged. We have no interest in hedging more volumes than are required. And that's the reason it's so conservative --

MR. ADAMS: Okay. So --

MR. RUBINO: -- including the lowest number of degree-days in the last ten years.

MR. ADAMS: When you're calculating the volumes eligible to be hedged, the formula that tells you how many -- what the volumes are, available to be hedged, makes no reference to the volume currently hedged; right?

MR. CHARLESON: Correct.

MR. RUBINO: Correct. That's correct.

MR. CHARLESON: Other than, if you were, you know -- as you use this formula, going forward, there's obviously going to be a relationship between what you're currently hedged -- the volumes that are available to currently hedge and what you're able to do in the future, because they're all based on the same formula, going forward.

MR. ADAMS: I -- that's not obvious to me. The formula is the formula.

MR. CHARLESON: Yes.

MR. ADAMS: It makes no reference to the volume currently hedged. If you had, you know, 100 million hedged, and the formula generates a figure of 120 million eligible to be hedged, are you going to add to that hedging quantity the next year?

MR. RUBINO: No. The --

MR. ADAMS: Where is that explained in your -- in --

MR. RUBINO: Well, this calculation is completed at the beginning of any given fiscal year. And that's the amount of volume that will be hedged over the next 12 months. It's what is available for hedging.

MR. CHARLESON: So I would agree with your comment that there isn't necessarily a direct link between what is available for hedging and what actually gets hedged. But, in terms of what's available for hedging, you would expect there to be a relatively close relationship from one year to the next, given that a number of these factors look back at numbers over the last ten years.

MR. ADAMS: Okay. Thank you for that.

Now, if we flip forward to VECC 28, at page 3, the company has asked a similar question in part F:

"Please explain the extent to which the company will be in a hedgible position, if the $75 tolerance level is accepted. In effect, please indicate the volume level that is currently hedged and, if the higher tolerance level is accepted, how much that level of hedged volumes would change."

That was the question.

And --

MR. CHARLESON: I'm just -- sorry to interrupt, but just to be clear. I think, at the beginning, when you were reading the first line of that, you just indicated the extent in which the company will be in a "hedgible position", where it was actually a "lower hedgible position."

MR. ADAMS: A "lower hedgible position." I --

MR. CHARLESON: Just for the record to be clear.

MR. ADAMS: I'm sorry.

Now, we look to the reply. The last sentence of that reply indicates:

"The company cannot, however, predict future price volatility, and, hence, cannot predict the associated volumes that may be hedged."

Right? Do you see that?

MR. RUBINO: It reads that -- you read it correctly.

MR. ADAMS: What -- my question is, what relationship does future price volatility have with respect to the formula that tells us the associated volumes that may be hedged?

MR. RUBINO: Well --

MR. CHARLESON: I think, in looking at that -- given that -- with the higher tolerance band and the potential of being in a hedgible position less often, that could lower the extent to which -- that you're -- the amount of -- how frequently you will be in a hedgible position, which can lead to you hedging less often. If you were to go through the whole year and you never exceed that band -- say, the band always -- say, $60 is the maximum that you ever see, well, you won't have hedged any volumes. With a $35 band, you would have exceeded that band, and so you would have hedged more volumes.

So there is the potential that, given the frequency that you may be in a hedgible position, it could have an impact on the total volumes hedged.

MR. ADAMS: I'm going to have to read the transcript to figure that out.

MR. CHARLESON: I hope I was clear enough for you.

MR. ADAMS: I'm going to turn to my last area of questions.

Okay. Now, Mr. Charleson, when you were discussing with the previous questioners your company's position with respect to transactional services, you drew attention to the necessity, in your view, of incentives for management. And I want you to turn you to a couple of transcript references. On page 88, volume 2, you said:

"I think as you look at the -- say, the risks and the uncertainties regarding the level of revenue, the level of gross margin, you want to ensure that there's still an appropriate incentive to attract management attention."

Later on in the transcript, you made a similar comment to Mr. De Vellis. And if the revenue -- sorry, this is Mr. De Vellis speaking:

"And if the revenues --

MR. CHARLESON: Perhaps, you could point us to the specific reference.

MR. ADAMS: Oh, I'm sorry. Page 92 - sorry - line 16 and following. Mr. De Vellis asked:

"And if the revenue -- sorry, the percentage of TS revenue that go to the company was, say, 10 percent rather than 50 percent, would these employees do their job any differently?"

Your response:

"Those employees -- I wouldn't expect them to do their job any differently. Again -- because, again, their focus is taking the assets that have been made available to them and trying to optimize the value that they're able to get. The concern that we have is, is the more management attention, management focus, also the manner in which we may look to manage other assets. So there's other parts of our -- of the way we manage our supply portfolio, the way we manage our -- the overall operation of our system, that may create opportunities for transactional services for these people to go and optimize. And that is more where our concern lies, from a sharing-mechanism perspective, and the management attention is: is there an incentive that these people, that aren't directly involved in the TS function, have, to try to ensure that there is an appropriate -- that there is that focus to try to provide the opportunities that make assets available for that person to then go and to optimize it. "

Now on the subject of TS, you testified that much richer incentives than those previously approved by the Board as applicable to TS are required to "get management's attention."

The utility has taken a similar view with respect to DSM, wherein its filing in this case, the proposed formula for SSM would yield a much higher ratio of return to the utility.

My question is this: With respect to risk management, your evidence is that there is a high level of top senior management spending a lot of time making sure that risk management is optimized, but it is all pro bono work, flow-through.

MR. CHARLESON: I guess there's a few aspects and a few characterizations that you have made in your statements there that I want to just try to address first.

First off, I can't speak to DSM and what is being requested there. I'm not the -- definitely not the expert in that area and not a witness on that evidence.

In terms of our transactional services, the request for the change to the sharing mechanism isn't necessarily a request for a much richer -- I forget the exact, precise words you used, but we're looking for what we believe is a fair sharing, given some of the uncertainties, and it may still result in us receiving a lower incentive than what we've had in the past, depending on what happens with transactional services revenues.

In terms of a significant amount of management attention, a significant amount of time, I think, as we've indicated, we hold risk management -- I agree there is attention from the senior levels within the organization towards risk management. We talk about one meeting a month. Those meetings are typically an hour or less in duration.

So, yes, the attention is there. Whether it's a significant amount of time, given the amount of time that our senior management would put in over the course of a month, I'm not sure that I would classify one hour even of -- assess another hour's preparation or discussion around risk management as being significant in the grand scheme.

You also indicated that, I think in your -- when you talked about significant time in terms of kind of the optimizing on the risk management. Again, that is not the objective of the program. The objective of the program is to mitigate volatility.

So I'm not sure if I have addressed your comments or if there is a specific question beyond that that you would like me to answer.

MR. ADAMS: What is the incentive driving senior management's attention to risk management?

MR. CHARLESON: Risk management is something that we see as being -- as related to more of a core activity of system supply. We have, as we've indicated, potentially around a million customers that rely on us for supplying their gas.

Those customers and -- well, all customers have indicated that they believe it is appropriate and that they would like to see the utility taking actions to mitigate that volatility. And, as a result, we have a risk-management program. That risk-management program, which has been approved by the Board, is in place to try to execute those customer wishes and what we see as being part of our core supply function.

And, also, given the dollars associated, the value of the transactions that come into play, you know, when we're looking this year, we have the potential -- heading towards this winter, there's the potential we could be looking at the value of the premiums that we pay alone in our caps being in the order of $40 million.

So there's significant costs that may be incurred in putting these transactions in place. Obviously, you don't know what the end result -- you know, you may have paid $40 million and it may end up having reduced costs by 42 or $45 million. You don't know what the outcome of those transactions are going to be, but given that there is that outlay or those costs that are incurred, it's something that is viewed as core and something that requires that attention.

MR. ADAMS: If any intervenors came forward and said that the utility ought to be accountable for ensuring lower gas costs by virtue of your risk-management program, you would resist that; right?

MR. CHARLESON: Yes. We would be very concerned with that, because I think as Risk Advisory indicated last year, for anybody to expect to beat the market on an ongoing basis is either very lucky or fooling themselves.

MR. RUBINO: "Unreasonable" was the word they used.

MR. CHARLESON: Yes. I paraphrased.

MR. ADAMS: Now, I will just close off with a couple of clean-up questions. In your evidence in-chief and your response to Mr. Warren, you commented that risk management had a different impact on the customer than equalization, bill equalization. Do you remember that discussion?

MR. CHARLESON: Yes, I do.

MR. ADAMS: Can you explain to me what the difference is, again?

MR. CHARLESON: Again, when we look at risk management

-- risk management is meant to mitigate the volatility in the prices that a customer will experience. But, ultimately, they're going to pay -- so it's mitigating the total price that they will pay for their commodity costs.

So, again, if we look at experience over the past few years, in total, you might have seen in one year a $20 million lower total commodity cost to system gas customers because of risk-management activities. So over a 12-month period, system gas customers will have paid $20 million less.

MR. ADAMS: What year was that?

MR. CHARLESON: Again --

MR. ADAMS: Energy Probe 93.

MR. CHARLESON: I guess I should be more careful in terms of just putting examples out there. Again, within Energy Probe 93, it shows that between 2004 and 2005 that the costs have actually been slightly higher.

MR. ADAMS: By 4- and 12 dollars.

MR. CHARLESON: By 4- and 12 dollars. But if we were to look back in the last proceeding, we also showed, in 2003, where the -- this was in CME Interrogatory No. 20, that the gain or the savings resulting from risk management was $23 million. So, again, just -- it can go one way or the other, but -- so for the use of my example, I chose a year where there was a savings resulting from the risk management.

So over the course of the years, system gas customers will have paid $23 million less than if there was no risk management program. If there was no risk management program and customers, instead, relied on equal billing to manage the volatility or to mitigate volatility, over the course of the year, it's true month over month what they pay will be smooth and there won't be dramatic fluctuations in there.

But at the end of the year, over the 12-month period, if all customers -- if all system gas customers were on equal billing, they still would have paid the $23 million more. So it hasn't -- or in the case of a year where there was -- you know, where risk management ended up costing more, they would have paid less.

So it has the effect of smoothing the timing of when they made those payments, but it doesn't remove, say, the impact of volatile gas prices on the total commodity costs they're going to pay over an annual basis.

MR. ADAMS: Mr. Charleson, that's looking at an annual basis. What about a customer over the long term, customers who buy gas on the long term? You have a house; you buy gas for 20, 30 years for the thing.

MR. CHARLESON: True.

MR. ADAMS: They're not expecting this risk management program to yield any benefits for that customer over a long-term period.

MR. CHARLESON: Correct.

MR. ADAMS: Whether they're on equal billing or not.

MR. CHARLESON: Yes, that's correct.

MR. ADAMS: So there is really no difference except

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the additional overheads. If you look at it on a long-term basis, the impact of your risk-management program is simply to increase the overhead costs borne by those system gas customers; right?

MR. CHARLESON: And if we look at the survey results it seems that it is something that customers have asked us -- or look for us to do. But, again, I can't disagree with the statement that you've made.

MR. ADAMS: Okay. The purpose of this -- let me just go back to the purpose of this expensive IT program you're putting in place, here. The IT program that it's replacing was something that was produced in-house, I assume --

MR. RUBINO: That's correct.

MR. ADAMS: -- by your own engineers -- your own staff?

MR. RUBINO: Our own staff.

MR. ADAMS: Now you're going to out -- to pay almost a million bucks for this new system. The benefits in the new system are primarily to protect the utility; right?

MR. CHARLESON: I would say it is to protect the utility ratepayer, because it helps us to administer the risk-management program, and ensure that we're executing the risk-management program in a manner that is consistent with what they desired, and in the manner that the Board has approved.

MR. ADAMS: If risk management -- if you guys had a rogue trader, or somebody that mismanaged this thing, and you came up with a big hit, there's a risk that the utility

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could get hit; right? We saw that with Central Gas Manitoba.

MR. CHARLESON: Yes, there is that risk.

MR. ADAMS: And so that risk needs to be managed prudently and carefully.

MR. CHARLESON: Yes. And perhaps that's why it receives the high level of management attention.

MR. ADAMS: Thank you.

Those are my questions.

MS. NOWINA: Thank you, Mr. Adams.

Mr. Dingwall, Miss DeMarco, can you give me a sense of how long your examination will take?

MR. DINGWALL: Madame, roughly half an hour, subject to negotiations with Ms. DeMarco, off the record, over the break.

MS. NOWINA: Ms. DeMarco?

MS. DeMARCO: I can guarantee that, come hick or come stick, we will be done by 4 o'clock today.

MS. NOWINA: Thank you. Even if we take a 15-minute break now?

MS. DeMARCO: Absolutely, Madam Chair.

MS. NOWINA: Let's take a 15-minute break, and we'll get back together at ten before the hour.

--- Recess taken at 2:35 p.m.

--- On resuming at 2:50 p.m.

MS. NOWINA: Please be seated. Mr. Dingwall, were you going to proceed next.

MR. O'LEARY: Madam Chair.

14. Good to its word, the Applicant has demonstrated that it just can't beat the market. And, unfortunately for the residential customers of Enbridge, recently it does not seem to be able to even get close. Data used in Table 1 below, with the exception of the right column and the bottom row, is drawn directly from Superior Energy Interrogatory #7[3].

Table 2

Year	EDG/Volume of Risk of Management Activity (m^3)	Cost of Risk Management – Purchases/Options (Gain/Loss) $Millions	Average AECO Spot Price of Gas Over Same Period ($C\$/10^3m^3$)	/U Impact of Risk Management on PGVA Price **
2006	**1,727,585***	**(110.0)***	**249.5***	**+0.66%***
2005	**2,041,077**	**19.0**	**303.0**	**-0.02%**
2004	**1,684,201**	**(4.3)**	**242.6**	**-0.05%**
2003	**1,262,802**	**23.4**	**239.4**	**-0.04%**
2002	**1,579,199**	**(40.8)**	**145.4**	**+0.76%**
2002-2006		**Net = (107.3)**		**+0.26%**

* as of Nov 2006; ** see Table 1, column Resulting Price Impact: Expressed As a % /U

The values in the column identified as "Impact of Risk Management on PGVA Price" represent the average impact of the risk management program on the PGVA reference price, as presented in Table 1, for each annual period and the overall five year period. /U

[3] Exhibit I/Tab 18/Sched. 7, p. 2, Response (a)

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ENERGY PROBE INTERROGATORY #19

INTERROGATORY

Ref: D1/T4/S3

Issue Number: 3.10
Issue: Is the continuation of the Risk Management Program appropriate in the context of the Board's 2006 Decision directives?

The Evidence at D1/T4/S3, beginning at Page 8, Paragraph 22, describes the EBP as follows:

> As a plan that is available to all residential heating customers (with certain restrictions), the EBP is designed to ease the customer's bill payments over the course of the year by spreading higher monthly payments that the customer would be faced with during the winter months. While this does inherently reduce the volatility a customer experiences in their gas bill, the EBP is not intended to protect customer bills from natural gas price volatility and should not be compared to the Program. The EBP is a payment option available to all customers, while the Program applies only to customers on system supply.

a) At D1/T4/S3, on Page 3 of 14, at Paragraph 10, the Evidence states that the QRAM methodology was developed to achieve or accommodate eight principles, with any reference to reducing volatility conspicuously and clearly absent. Why does the Applicant believe that the EBP should not be compared to the Risk Management Program, when both can operate with the QRAM independently of the other?

b) Please provide a table showing the incremental costs, both O&M and capital, of the Applicant's Equal Billing Plan for each of the years 2002 to 2005 (actual); 2006 (most recent forecast) and 2007 (budget).

RESPONSE

a) Enbridge Gas Distribution believes that the Equal Billing Plan (now called the Budget Billing Plan) should not be compared to the Risk Management Program as the Plan is not limited solely to system gas customers and does not impact the price the

Witnesses: A. Creery
D. Charleson
K. Irani
S. McGill

customer pays for their commodity. The Budget Billing Plan only impacts the timing of when they pay for their distribution and commodity costs, not the actual costs they pay. The Risk Management Program directly impacts the commodity costs paid by system gas customers.

b) There are no incremental costs related to the Budget Billing Plan.

Witnesses: A. Creery
D. Charleson
K. Irani
S. McGill

ENERGY PROBE INTERROGATORY #21

INTERROGATORY

Ref: D1/T4/S3

Issue Number: 3.10
Issue: Is the continuation of the Risk Management Program appropriate in the context of the Board's 2006 Decision directives?

a) For a customer using the average volume of gas, what has been the average bill impact of risk management for the period 2002-2006?

b) For the two most recent QRAMs, please provide a detailed explanation of how the PGVA without risk management is calculated.

RESPONSE

a) Assuming a typical heating and water heating customer will consume approximately 3,062 m^3 of gas over the course of the year, if the Purchase Gas Variance Account ("PGVA") reference price is used as a proxy to determine the customer commodity cost, the average bill impact of risk management on a calendar year basis for the period 2002-2005 has been (in dollars and cents):

Year	PGVA based Commodity cost with Risk Management	PGVA based Commodity cost without Risk Management	Bill Impact of Risk Management
2002	684.82	679.55	5.27
2003	852.25	851.98	0.26
2004	898.99	898.24	0.76
2005	1,108.62	1,110.62	(2.00)
2006	1,324.37	1,319.63	4.74
Average	973.81	972.01	1.80

Witnesses: D. Charleson
K. Irani
D. Small

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b) Please find attached a copy of an explanation of the manner in which the PGVA reference price is calculated for the purposes of the QRAM and how Risk Management activities are incorporated into this calculation that was originally filed in the EB-2004-0492 proceeding at Exhibit Q2-2, Tab 1, Schedule 1. The same methodology has been used to calculate the PGVA for the two most recent QRAMs.

To determine the PGVA without Risk Management, only the steps identified in paragraphs 2 through 4 would be used. The remaining steps related to Risk Management impacts would be excluded.

Witnesses: D. Charleson
K. Irani
D. Small

QRAM METHODOLOGY AND RISK MANAGEMENT

Purpose of Evidence

1. The purpose of this evidence is to respond to the concerns expressed by the Board in its Decision in RP-2003-0203 regarding the impact of a rolling 12-month hedge period on the QRAM methodology.
2. The current QRAM methodology applies a 21-day average of future monthly indices to the Board approved gas supply portfolio in order to calculate an average annual gas acquisition cost inclusive of risk management transactions and upstream transportation costs.
3. For example, the October 1, 2004 Reference Price was based upon a 21-day average of various prices from July 16, 2004 to August 13, 2004 for the 12 months commencing October 1, 2004 and applied those monthly prices to the 2005 budgeted annual volume of gas purchases. The forecasted October 2004 AECO price was applied to the budgeted October 2004 AECO purchases, the forecasted November 2004 AECO price was applied to the budgeted November 2004 AECO purchases, ... the forecasted September 2005 AECO price was applied to the budgeted September 2005 AECO purchases, etc, etc.
4. For subsequent QRAM's the same annual Board approved volumes are used assuming a future 12-month period. For example, The January 1, 2005 Reference price was based upon a 21-day average of various prices from October 18, 2004 to November 15, 2004 for the 12 months commencing January 1, 2005. The forecasted October 2005 AECO price was applied to the budgeted October 2004 AECO purchases etc, etc.
5. As we move through the fiscal year the Company may or may not enter into risk management transactions dependent upon the outputs of the Risk Management Model. To the extent that the Company does enter into risk management

transactions they are only entered into up until the end of the current fiscal year. Using the same 21-day average of prices used in calculating the projected cost of the budgeted physical supplies the projected cash settlement of any risk management transaction can be forecasted. This forecast is included in the derivation of the Reference Price.

6. For example, under the current approach, in calculating the January 1, 2005 Reference Price any risk management transaction entered into by November 15, 2004 that covered the January 2005 to September 2005 period would be included in the derivation of that price. The forecasted January 2005 AECO price would be applied to January 2005 AECO risk management transactions, the forecasted February 2005 AECO price would be applied to February 2005 AECO risk management transactions, ... the forecasted September 2005 AECO price would be applied to September 2005 risk management transactions, etc, etc.
7. In RP-2003-0203 the Company proposed a number of changes to its Risk Management Program. Among them was the concept of a rolling 12-month hedge period. The concept was that if a Reference Price was being established for a rolling 12-month period then the Company should be allowed to enter into risk management transactions in months that matched the period of the QRAM even if it went beyond the fiscal year end date. For example, if the January 2005 Reference Price was based upon prices for 12 months commencing January 1, 2005 then the Company should be allowed to enter into risk management transactions that covered that same period.
8. Once a transaction has been entered into then the forecasted financial settlement of that transaction would be included in the derivation of the reference price. Therefore, for purposes of the QRAM, there is no change in methodology by moving to the inclusion of a rolling 12-month hedging period.

ENERGY PROBE INTERROGATORY #24

INTERROGATORY

Ref: D1/T4/S3

Issue Number: 3.10
Issue: Is the continuation of the Risk Management Program appropriate in the context of the Board's 2006 Decision directives?

During the Oral Hearing in the EB2005-0001 Enbridge Gas Distribution 2006 Rates Case, on Day 5, very early on in that proceeding, Mr. Warren was cross-examining Mr. Charleson on evidence submitted in that proceeding by Mr. Adams of Energy Probe, and elicited the following response from Mr. Charleson:

> So given that there is the potential that, at periods of time, the cost -- commodity cost will be higher as a result of risk-management activities. However -- and I believe, in the proceeding last year, Mr. Smart from Risk Advisory testified that, over a longer period of time, the expectation would be that the impacts of the risk-management program should ultimately be cost-neutral, that, if you look - whether it's a five- or looking over a ten-year horizon, you're going to have some years where costs may be higher as a result of risk-management actions. There will be years where the risks are lower. But, in essence, the program should balance out. The principle of the program is not to try to beat the market. It is to mitigate and suppress volatility.
> (EB-2005-0001 Transcript Vol 5, Page 69, beginning at Line 9)

a) Is it still the position of the Applicant, as advised by Mr. Smart, that the Risk Management Program should be cost neutral, that the Program should balance out?

b) Is it still the position of the Applicant, as advised by Mr. Smart, that the Risk Management Program should not try to beat the market?

c) How does the Applicant define "beat the market"? Does that refer to an attempt to beat the wholesale commodity price?

Witnesses: D. Charleson
K. Irani

RESPONSE

a) The correct name of the Risk Advisory consultant is Mr. Simard. A correction to this error in the EB-2005-001 Transcript was missed by the Company during that proceeding. It is still the position of Enbridge Gas Distribution that over the long term, the outcome of Risk Management activities should be cost neutral.

b) Yes.

c) The Company's view is that attempting to "beat the market" would mean that a party would be consistently trying to ensure that its hedging activities resulted in a lower cost than if it had not undertaken any hedge activities. Achieving this would typically require correctly speculating on the future direction of market prices and taking the appropriate financial position.

Witnesses: D. Charleson
K. Irani

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ENERGY PROBE INTERROGATORY #25

INTERROGATORY

Ref: D1/T4/S3

Issue Number: 3.10
Issue: Is the continuation of the Risk Management Program appropriate in the context of the Board's 2006 Decision directives?

The evidence at D1/T4/S3, Page 11 of 14, at Paragraph 29 refers to the survey of customers that the Applicant undertook late in 2004, and quotes as follows:

> The survey found that a majority of customers want price volatility risk to be managed, thus reinforcing the Company's view that reduced price volatility is of considerable interest to customers."

a) Please advise that it is still the position of the Applicant that the survey found that customers showed little differences in opinion on the value of the risk management, whether or not they were part of the Program, and as opined by Mr. Rubino in response to Mr. O'Leary during questions-in-chief:

   The company disagrees with this assertion that the survey was biased. Both system-gas and direct-purchase customers were included in the survey. And the survey found that there were no significant differences between the responses of direct-purchase customers -- as compared to those of system-gas customers.
   (EB-2005-0001 Transcript Vol 5, Page 63, beginning at Line 28)

b) Please advise that it is still the position of the Applicant that the survey found that the customers most tolerant of bill fluctuations were as described by Mr. Rubino during questions-in-chief by Mr. O'Leary:

   The attachment at Exhibit A3, tab 3, schedule 1, page 33, indicates that, in fact, those customers who are system-gas customers, but believe they're on direct-purchase are the most tolerant of bill fluctuations.
   (EB-2005-0001 Transcript Vol 5, Page 64, beginning at Line 13)

Witnesses: D. Charleson
K. Irani

RESPONSE

a) The survey results have not been updated or changed since the EB-2005-0001 proceeding. As a result, the position of Enbridge Gas Distribution has not changed.

b) The survey results have not been updated or changed since the EB-2005-0001 proceeding. As a result, the position of Enbridge Gas Distribution has not changed.

Witnesses: D. Charleson
K. Irani

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ENERGY PROBE INTERROGATORY #16

INTERROGATORY

Ref: D1/T4/S1 & D1/T4/S2

Issue Number: 3.1
Issue: Is the proposed 2007 gas cost forecast including the calculation of the PGVA Reference Price appropriate?

a) Please confirm that the anticipated cost of hedge instruments related to transactions of the Applicant's Risk Management Program is folded into the calculation of the gas cost forecast to develop the PGVA Reference Price.

b) Please confirm that the actual cost of hedge instruments related to transactions of the Applicant's Risk Management Program is trued up each quarter in the QRAM.

c) Please advise the number of years the Applicant retains a record of the method of calculation of its annual gas cost forecast, and the calculation itself.

d) Please advise the number of years the Applicant retains a record of each transaction undertaken as part its Risk Management Program, and the cost (expense) of each of those transactions.

RESPONSE

a) Confirmed. See response to Energy Probe Interrogatory # 21 at Exhibit I, Tab 5, Schedule 21.
b) The actual cost of hedge instruments, like actual acquisition costs, are imbedded in the year projected PGVA balance that is presented as a part of the QRAM for determination on whether or not there should be a Rider.
c) The PGVA mechanism has been in place for more than 10 years. There has not been a material change to the PGVA methodology since that time. EGD has available the pertinent details of the PGVA calculation since the inception of the QRAM in January 2002.
d) EGD has maintained a record of each transaction undertaken as part of its Risk Management Program, and the cost (expense) of each of those transactions since the inception of the Risk Management program.

Witnesses: D. Charleson
D. Small

ENERGY PROBE INTERROGATORY #17

INTERROGATORY

Ref: D1/T4/S1 & D1/T4/S2

Issue Number: 3.1
Issue: Is the proposed 2007 gas cost forecast including the calculation of the PGVA Reference Price appropriate?

a) Please provide the Board with the forecast cost (expense), as reflected in the PGVA Reference Price, of the hedge instruments related to transactions of the Applicant's Risk Management Program for each year from 2002-2006, and the for the Test Year.

b) Please provide the Board with a table tabulating the cost (expense) of those hedge instruments related to transactions of the Applicant's Risk Management Program by quarter for each year from 2002-2005 (actual), 2006 (most recent forecast) and 2007 (budget), and indicating the variance between forecast and actual on an annual basis.

RESPONSE

a) A description of the QRAM methodology has been filed as part of response to Energy Probe Interrogatory # 21. Table 1 (attached) provides the PGVA Reference Price as per each QRAM effective January 1, 2002 (Col 3). It also provides the forecasted Risk Management cost at the time of the preparation of that QRAM (Col 4) and what the Reference Price would have been if Risk Management was not included (Col 6). To reiterate, any Risk Management transaction that had been entered into 45 days prior to the effective date of the QRAM would be included in the derivation of the PGVA Reference Price using the same 21 day average of prices that is applied to the forecasted volumes for rate making purposes. Any change in those prices will impact the final outcome of those Risk Management transactions just as it will impact the cost of the physical supplies being acquired. Any variation in the monthly acquisition cost including Risk Management as referenced against the PGVA Reference Price will be charged to the PGVA account.

Witnesses: D. Charleson
D. Small

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b) Table 2 attached provides the actual monthly acquisition cost (Col 1) and actual monthly risk management cost (Col 4) for the years 2002 to 2005. Column 3 of the table provides the average monthly acquisition cost unit rate excluding the impact of risk management activity and Column 6 represents the monthly acquisition cost unit rate including Risk Management. For comparative purposes the risk management costs as a percentage of the annual acquisition cost has been provided.

Witnesses: D. Charleson
D. Small

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Table 1

	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5 (Col.2 - Col.4)	Col. 6	Col. 7 (Col.3 - Col.6)	Col. 8 (Col.4 / Col. 5)
	QRAM Forecast Volumes 10*3 m*3	QRAM Forecast Costs $(000)	PGVA Reference Price $/10*3 m*3	Forecasted Risk Management $(000)	QRAM Costs without Risk Management $(000)	PGVA without Risk Management $/10*3 m*3	Risk Management Impact $/10*3 m*3	%
January 1, 2002 QRAM	4,859,665.5	1,071,371.2	220.462	10,890.4	1,060,480.8	218.221	2.241	1.03
April 1, 2002 QRAM	4,686,351.0	906,915.3	193.523	22,212.6	884,702.7	188.783	4.740	2.51
July 1, 2002 QRAM	4,686,351.0	1,185,062.1	252.875	(6,247.5)	1,191,309.6	254.208	(1.333)	(0.52)
October 1, 2002 QRAM	3,728,052.4	887,139.1	237.963	-	887,139.1	237.963	-	-
January 1, 2003 QRAM	4,165,740.4	1,081,089.8	259.519	1,682.7	1,079,407.0	259.115	0.404	0.16
April 1, 2003 QRAM	4,165,740.4	1,303,365.0	312.877	(2,339.5)	1,305,704.6	313.439	(0.562)	(0.18)
July 1, 2003 QRAM	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
October 1, 2003 QRAM	4,142,394.0	1,160,621.7	280.181	442.2	1,160,179.6	280.075	0.107	0.04
January 1, 2004 QRAM	4,142,394.0	1,090,264.1	263.197	3,562.0	1,086,702.1	262.337	0.860	0.33
April 1, 2004 QRAM	4,142,394.0	1,213,267.9	292.891	(1,177.5)	1,214,445.4	293.175	(0.284)	(0.10)
July 1, 2004 QRAM	4,142,394.0	1,379,047.5	332.911	(5,937.7)	1,384,985.2	334.344	(1.433)	(0.43)
October 1, 2004 QRAM	5,032,476.1	1,671,970.6	332.236	-	1,671,970.6	332.236	-	-
January 1, 2005 QRAM	5,032,476.1	1,793,207.8	356.327	(12,364.0)	1,805,571.9	358.784	(2.457)	(0.68)
April 1, 2005 QRAM	5,032,476.1	1,606,796.6	319.285	5,465.4	1,601,331.2	318.199	1.086	0.34
July 1, 2005 QRAM	5,032,476.1	1,790,075.4	355.705	(399.8)	1,790,475.2	355.784	(0.079)	(0.02)
October 1, 2005 QRAM	5,032,476.1	1,995,712.2	396.567	5,549.9	1,990,162.3	395.464	1.103	0.28
January 1, 2006 QRAM	4,995,136.3	2,418,617.8	484.195	(3,887.1)	2,422,504.9	484.973	(0.778)	(0.16)
April 1, 2006 QRAM	4,995,136.3	1,995,964.2	399.582	15,556.1	1,980,408.1	396.467	3.114	0.79
July 1, 2006 QRAM	4,995,136.3	1,906,602.8	381.692	18,960.7	1,887,642.0	377.896	3.796	1.00
October 1, 2006 QRAM	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

loss / gain
?. ?

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Table 2

	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9
			(Col.1/Col.2)		(Col.1+Col.4)	(Col.5/Col.2)		(Col.6+Col.7)	(Col.8/Col.
	Gas Acquisition Costs $(000)	Acquired Volumes 10*3 m*3	$/10*3 m*3	Risk Management Impact $(000)	Risk Management Adjusted Cost $(000)	$/10*3 m*3	PGVA Adjustment $(000)	Deemed Acquisition Cost $(000)	PGVA Reference Price $/10*3 m*3
2002									
January	43,775.3	226,272.4	193.463	4,317.1	48,092.4	212.542	1,792.1	49,884.5	220.462
February	41,008.3	224,344.8	182.792	7,084.0	48,092.3	214.368	1,367.2	49,459.5	220.462
March	35,614.8	181,656.7	196.055	6,403.8	42,018.6	231.308	(1,970.2)	40,048.4	220.462
April	49,973.2	219,824.3	227.332	(546.8)	49,426.4	224.845	(6,885.3)	42,541.1	193.523
May	65,329.4	298,789.4	218.647	(982.7)	64,346.7	215.358	(6,524.1)	57,822.6	193.523
June	59,525.0	282,277.8	210.874	549.0	60,074.0	212.819	(5,446.8)	54,627.2	193.523
July	71,760.2	389,179.9	184.388	4,181.9	75,942.1	195.134	22,471.8	98,413.9	252.875
August	63,912.0	387,779.7	164.815	7,598.5	71,510.5	184.410	26,549.3	98,059.8	252.875
September	59,456.7	305,984.6	194.313	2,994.2	62,450.9	204.098	14,925.0	77,375.9	252.875
October	76,029.9	328,074.2	231.746	-	76,029.9	231.746	2,039.7	78,069.5	237.963
November	105,629.3	399,493.4	264.408	505.7	106,135.0	265.674	(11,070.3)	95,064.6	237.963
December	105,349.0	402,019.3	262.050	947.9	106,296.9	264.408	(10,631.2)	95,665.7	237.963
	777,363.0	3,645,696.4	213.228	33,052.6	810,415.6	222.294	26,617.0	837,032.7	229.595
Risk Management as a percentage of Acquisition Costs				4.25					
2003									
January	198,269.1	643,092.4	308.306	(1,661.3)	196,607.9	305.723	(29,713.2)	166,894.7	259.519
February	272,975.4	631,009.4	432.601	(4,923.3)	268,052.0	424.799	(104,293.1)	163,758.9	259.519
March	276,281.7	580,985.7	475.540	(21,944.6)	254,337.1	437.768	(103,560.3)	150,776.8	259.519
April	118,004.9	379,500.2	310.948	(485.5)	117,519.4	309.669	1,217.5	118,736.9	312.877
May	102,047.3	338,141.3	301.789	268.3	102,315.6	302.582	3,481.1	105,796.6	312.877
June	100,697.2	318,903.2	315.761	(173.2)	100,524.1	315.218	(746.6)	99,777.5	312.877
July	107,161.8	359,162.5	298.366	42.3	107,204.1	298.484	5,169.6	112,373.7	312.877
August	84,166.7	329,780.9	255.220	2,665.4	86,832.1	263.302	16,348.8	103,180.9	312.877
September	94,639.1	339,520.9	278.743	1,385.2	96,024.3	282.823	10,204.0	106,228.3	312.877
October	86,774.2	335,055.7	258.984	381.5	87,155.7	260.123	6,720.5	93,876.2	280.181
November	97,008.0	384,282.4	252.439	2,284.2	99,292.2	258.383	8,376.4	107,668.6	280.181
December	137,281.2	498,129.2	275.594	2,632.3	139,913.5	280.878	(347.1)	139,566.3	280.181
	1,675,306.7	5,137,563.8	326.090	(19,528.8)	1,655,777.9	322.289	(187,142.4)	1,468,635.5	285.862
Risk Management as a percentage of Acquisition Costs				(1.17)					
2004									
January	172,077.0	506,607.4	339.665	(3,210.3)	168,866.7	333.328	(35,529.1)	133,337.5	263.197
February	126,796.7	418,968.9	302.640	(566.1)	126,230.6	301.289	(15,959.2)	110,271.4	263.197
March	97,680.0	349,455.9	279.520	5,151.9	102,831.9	294.263	(10,856.1)	91,975.7	263.197
April	99,503.7	343,798.7	289.424	184.9	99,688.6	289.962	1,007.0	100,695.6	292.891
May	105,514.6	342,182.5	308.358	(690.0)	104,824.6	306.341	(4,602.5)	100,222.2	292.891
June	109,995.3	331,057.1	332.255	(3,228.1)	106,767.2	322.504	(9,803.5)	96,963.6	292.891
July	145,749.3	476,835.3	305.660	(1,570.1)	144,179.2	302.367	14,564.5	158,743.7	332.911
August	138,917.1	478,215.7	290.491	(285.8)	138,631.3	289.893	20,572.0	159,203.3	332.911
September	101,671.6	400,378.3	253.939	3,377.8	105,049.4	262.375	28,241.0	133,290.3	332.911
October	70,498.6	254,521.0	276.985	-	70,498.6	276.985	14,062.4	84,561.0	332.236
November	129,304.6	357,839.7	361.348	31.4	129,336.0	361.436	(10,448.8)	118,887.2	332.236
December	161,565.8	474,518.2	340.484	4,759.8	166,325.7	350.515	(8,673.6)	157,652.0	332.236
	1,459,274.3	4,734,378.8	308.229	3,955.4	1,463,229.7	309.065	(17,426.0)	1,445,803.7	305.384
Risk Management as a percentage of Acquisition Costs				0.27					
2005									
January	160,784.8	508,205.4	316.378	9,730.3	170,515.2	335.524	10,572.1	181,087.3	356.327
February	119,940.3	405,114.9	296.065	9,340.5	129,280.8	319.121	15,072.6	144,353.4	356.327
March	184,831.0	598,717.2	308.712	10,676.8	195,507.8	326.544	17,831.3	213,339.1	356.327
April	124,672.3	364,889.5	341.671	(1,048.7)	123,623.5	338.797	(7,119.8)	116,503.8	319.285
May	113,460.8	353,833.7	320.661	(533.8)	112,927.0	319.153	46.9	112,973.8	319.285
June	102,940.1	340,033.6	302.735	2,623.6	105,563.7	310.451	3,004.0	108,567.6	319.285
July	113,580.2	343,057.4	331.082	(201.6)	113,378.7	330.495	8,648.6	122,027.2	355.705
August	148,517.0	428,990.8	346.201	(1,111.8)	147,405.2	343.609	5,189.0	152,594.2	355.705
September	188,904.3	425,592.3	443.862	(16,908.3)	171,996.0	404.133	(20,610.7)	151,385.3	355.705
October	162,465.1	303,136.6	535.947	-	162,465.1	535.947	(42,251.3)	120,213.9	396.567
November	173,655.6	353,462.3	491.299	(3,013.1)	170,642.5	482.774	(30,471.1)	140,171.4	396.567
December	333,556.0	665,069.8	501.535	7,924.7	341,480.7	513.451	(77,736.2)	263,744.5	396.567
	1,927,307.4	5,090,103.7	378.638	17,478.7	1,944,786.1	382.072	(117,824.6)	1,826,961.5	358.924
Risk Management as a percentage of Acquisition Costs				0.91					

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ENERGY PROBE INTERROGATORY #18

INTERROGATORY

Ref: D1/T4/S3

Issue Number: 3.10
Issue: Is the continuation of the Risk Management Program appropriate in the context of the Board's 2006 Decision directives?

The Evidence at D1/T4/S3, Page 6 of 14 at Paragraph 17 states:

> To assess the effect of the Program on reducing overall price volatility in the QRAM, the Company analyzed the impact of the Program on the PGVA for the period January 1, 2002 up to and including April 1, 2006. The Company believes this is the most appropriate means of assessing the effectiveness of the Program, as the PGVA reference price is a key determinant in the setting of the QRAM price.

And again at Paragraph 18, the Evidence continues as follows:

> Table 2 compares the absolute change in the PGVA reference price for each quarter, with or without the Program.

a) Please complete Table A below to demonstrate the Equal Billing Plan impact on price volatility of the hedged portfolio.

b) Please complete Table B below to demonstrate the Equal Billing Plan impact on price volatility of the unhedged portfolio used in Table 2 of the Evidence on Page 7 of 14.

Witnesses: D. Charleson
K. Irani

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Table A – EQUAL BILLING PLAN IMPACT ON PRICE VOLATILITY
2002-2006
Hedged Portfolio

	Residential Consumer Per 273 m3 Monthly With RM	Quarterly Price Change Per 273 m3	Equal Billing Price Per 273 m3 With RM	Quarterly Price Change Per 273 m3	Percentage Reduction in Volatility (%)
Date					
1-Jan-02					
1-Apr-02					
1-Jul-02					
1-Oct-02					
1-Jan-03					
1-Apr-03					
1-Jul-03					
1-Oct-03					
1-Jan-04					
1-Apr-04					
1-Jul-04					
1-Oct-04					
1-Jan-05					
1-Apr-05					
1-Jul-05					
1-Oct-05					
1-Jan-06					
1-Apr-06					
1-Jul-06					

Witnesses: D. Charleson
K. Irani

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Table B – EQUAL BILLING PLAN IMPACT ON PRICE VOLATILITY
2002-2006
Unhedged Portfolio

	Residential Consumer Per 273 m3 Monthly No RM	Quarterly Price Change Per 273 m3	Equal Billing Price Per 273 m3 No RM	Quarterly Price Change Per 273 m3	Percentage Reduction in Volatility (%)
Date					
1-Jan-02					
1-Apr-02					
1-Jul-02					
1-Oct-02					
1-Jan-03					
1-Apr-03					
1-Jul-03					
1-Oct-03					
1-Jan-04					
1-Apr-04					
1-Jul-04					
1-Oct-04					
1-Jan-05					
1-Apr-05					
1-Jul-05					
1-Oct-05					
1-Jan-06					
1-Apr-06					
1-Jul-06					

RESPONSE

The unit cost of gas that a customer pays in their bill is not impacted in any way by the Equal Billing Plan (now called the Budget Billing Plan). This plan is intended to spread higher monthly payments for commodity and distribution services over the course of the year. The price that a customer ultimately pays, whether driven by the system gas rate or the direct purchase arrangements of the customer, is not impacted in any way by the

Witnesses: D. Charleson
K. Irani

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Budget Billing Plan. The Budget Billing Plan strictly changes the timing of when the price is paid. The requested tables are provided below with the "Equal Billing Price" being the commodity price for a system gas customer.

Table A - EQUAL BILLING PLAN IMPACT OF PRICE VOLATILITY
2002-2006
Hedged Portfolio

	Residential Consumer Per 273 m3 Monthly With RM	Quarterly Price Change Per 273 m3	Equal Billing Price Per 273 m3 With RM	Quarterly Price Change Per 273 m3	Percentage Reduction in Volatility (%)
Date					
1-Jan-02	60.19		60.19		
1-Apr-02	52.83	(7.35)	52.83	(7.35)	-
1-Jul-02	69.03	16.20	69.03	16.20	-
1-Oct-02	64.96	(4.07)	64.96	(4.07)	-
1-Jan-03	70.85	5.88	70.85	5.88	-
1-Apr-03	85.42	14.57	85.42	14.57	-
1-Jul-03	85.42	-	85.42	-	-
1-Oct-03	76.49	(8.93)	76.49	(8.93)	-
1-Jan-04	71.85	(4.64)	71.85	(4.64)	-
1-Apr-04	79.96	8.11	79.96	8.11	-
1-Jul-04	90.88	10.93	90.88	10.93	-
1-Oct-04	90.70	(0.18)	90.70	(0.18)	-
1-Jan-05	97.28	6.58	97.28	6.58	-
1-Apr-05	87.16	(10.11)	87.16	(10.11)	-
1-Jul-05	97.11	9.94	97.11	9.94	-
1-Oct-05	108.26	11.16	108.26	11.16	-
1-Jan-06	132.19	23.92	132.19	23.92	-
1-Apr-06	109.09	(23.10)	109.09	(23.10)	-
1-Jul-06	104.20	(4.88)	104.20	(4.88)	-

Witnesses: D. Charleson
K. Irani

Table B - EQUAL BILLING PLAN IMPACT OF PRICE VOLATILITY
2002-2006
Unhedged Portfolio

	Residential Consumer Per 273 m3 Monthly With RM	Quarterly Price Change Per 273 m3	Equal Billing Price Per 273 m3 With RM	Quarterly Price Change Per 273 m3	Percentage Reduction in Volatility (%)
Date					
1-Jan-02	59.57		59.57		
1-Apr-02	51.54	(8.04)	51.54	(8.04)	-
1-Jul-02	69.40	17.86	69.40	17.86	-
1-Oct-02	64.96	(4.43)	64.96	(4.43)	-
1-Jan-03	70.74	5.77	70.74	5.77	-
1-Apr-03	85.57	14.83	85.57	14.83	-
1-Jul-03	85.57	-	85.57	-	-
1-Oct-03	76.46	(9.11)	76.46	(9.11)	-
1-Jan-04	71.62	(4.84)	71.62	(4.84)	-
1-Apr-04	80.04	8.42	80.04	8.42	-
1-Jul-04	91.28	11.24	91.28	11.24	-
1-Oct-04	90.70	(0.58)	90.70	(0.58)	-
1-Jan-05	97.95	7.25	97.95	7.25	-
1-Apr-05	86.87	(11.08)	86.87	(11.08)	-
1-Jul-05	97.13	10.26	97.13	10.26	-
1-Oct-05	107.96	10.83	107.96	10.83	-
1-Jan-06	132.40	24.44	132.40	24.44	-
1-Apr-06	108.24	(24.16)	108.24	(24.16)	-
1-Jul-06	103.17	(5.07)	103.17	(5.07)	-

Witnesses: D. Charleson
K. Irani

K 2.6

Analysis of Revenue to Cost Ratios for Rate 1 with and without Upstream Cost allocation changes implemented in Fiscal 2005

	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8
		Revenues ($000)	Costs ($000)	Over / (Under) Contribution ($000)	Revenue to Cost Ratios	Phase-in Adjustment ($000)	Over / (Under) Contribution Adjusted ($000)	Revenue to Cost Ratios Adjusted
	2001	747,150	752,910	(5,760)	0.99	20,817	15,057	1.02
	2002	750,610	759,430	(8,820)	0.99	21,020	12,200	1.02
	2003	803,972	813,405	(9,433)	0.99	21,209	11,776	1.01
	2004	n/a	n/a	n/a	n/a	n/a		
	2005	873,830	867,650	6,180	1.01	(8,722)	(2,542)	1.00
	2006	899,330	890,580	8,750	1.01	(5,405)	3,345	1.00
As Filed	2007	956,460	940,950	15,510	1.02	(5,010)	10,500	1.01
ADR @ $26M	2007	855,195	844,839	10,356	1.01	(5,010)	5,346	1.01

Notes:
Col 2 = Approved Revenues excluding Commodity
Col 3 = Approved Costs excluding Commodity
Col 4 = Revenues - Costs
Col 5 = Revenues/Costs
Col 6 = Adjustment to reflect currently approved upstream cost allocation methodology
Impact of full implementation of approved methodology in 2005 = 0.5 c/m3 for Rate 1 customers
Impact for 2001-2003 derived as 0.5 c/m3*Rate 1 volumes
Col 7 = Col 2 + Col 6
Col 8 = Col 2/(Col 3-Col 6) for 2001- 2003
Col 8 = (Col 2+Col 6)/Col 3 for 2005-2007

Ontario Energy Board
FILE No. EB-2006-0034
EXHIBIT No. K.2.6
DATE January 29, 2007
08/99

Analysis of Revenue to Cost Ratios for Rate 6 with and without Upstream Cost allocation changes implemented in Fiscal 2005

	Col. 1	*Col. 2*	*Col. 3*	*Col. 4*	*Col. 5*	*Col. 6*	*Col. 7*	*Col. 8*
		Revenues	Costs	Over Contribution	R/C	Phase-in Adjustment	Over Cont. Adjusted	R/C Adjusted
	2001	382,497	375,764	6,733	1.02	15,742	22,475	1.06
	2002	382,469	376,713	5,756	1.02	16,004	21,760	1.06
	2003	397,408	395,259	2,149	1.01	15,599	17,748	1.05
	2004	n/a	n/a	n/a	n/a	n/a		
	2005	415,635	405,317	10,318	1.03	(8,722)	1,596	1.00
	2006	414,114	409,920	4,194	1.01	(5,181)	(987)	1.00
As Filed	2007	407,811	405,126	2,685	1.01	(4,892)	(2,207)	0.99
ADR@$26M	2007	373,847	368,783	5,064	1.01	(4,892)	172	1.00

Notes:
Col 2 = Approved Revenues excluding Commodity
Col 3 = Approved Costs excluding Commodity
Col 4 = Revenues - Costs
Col 5 = Revenues/Costs
Col 6 = Adjustment to reflect currently approved upstream cost allocation methodology
Impact of full implementation of approved methodology in 2005 = 0.5 c/m3 for Rate 6 customers
Impact for 2001-2003 derived as 0.5 c/m3*Rate 6 volumes
Col 7 = Col 2 + Col 6
Col 8 = Col 2/(Col 3-Col 6) for 2001- 2003
Col 8 = (Col 2+Col 6)/Col 3 for 2005-2007