Enbridge Gas
2007 Test Year Rate Case

EB-2006-0034

EXHIBIT LIST

K	Exhibits filed at the Hearing	Date Filed
	NO EXHIBITS WERE FILED	**January 22, 2007**
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, 2007**
2.2	EXTRACT FROM NATURAL GAS FORUM DOCUMENT ENTITLED "NATURAL GAS REGULATION IN ONTARIO: A RENEWED POLICY FRAMEWORK", PROVIDED BY MR. BUONAGURO	
2.3	THREE-PAGE DOCUMENT FROM PREVIOUS UNION RATES CASE, ENTITLED "RISK MANAGEMENT IMPACT ON WACOG AND PGVA"	
2.4	ENERGY PROBE COMPENDIUM OF DOCUMENTS, ENTITLED "CROSS-EXAMINATION MATERIAL ON RISK MANAGEMENT, ENERGY PROBE RESEARCH FOUNDATION, JANUARY, 2007"	
2.5	ENBRIDGE CUSTOMER SURVEY ON RISK MANAGEMENT	
2.6	SPREADSHEET TITLED "ANALYSIS OF REVENUE TO COST RATIOS FOR RATE 1 AND ANALYSIS OF REVENUE TO COST RATIOS FOR RATE 6."	
3.1	VECC INTERROGATORY NO. 73 FROM EB-2005-0001	**January 30, 2007**
4.1	DOCUMENT ENTITLED "2007 TEST YEAR APPROXIMATE ELEMENTS OF CHANGES IN VOLUMES AND STORAGE DEFICIENCY AMOUNTS"	**February 1, 2007**
4.2	DOCUMENT ENTITLED: "COMPARISON OF NINE DIFFERENT DEGREE DAY FORECAST METHODOLOGIES"	
4.3	UNDERTAKING N3.2 FROM RP-2003-0063	
4.4	TABLE SHOWING ACTUAL AND FORECAST TORONTO DEGREE DAYS	

K	Exhibits filed at the Hearing	Date Filed
4.5	DOCUMENT ENTITLED "DEGREE DAY METHODOLOGIES - COMPARISON OF PERFORMANCE 1990-2005"	
4.6	ENERGY PROBE COMPENDIUM OF DOCUMENTS	

J	Undertakings	Hearing Date	Response Filed
	NO UNDERTAKINGS WERE FILED	**January 22, 2007**	
		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		February 1, 2007
2.2	ADVISE WHETHER EGDI OBTAINS FINANCIAL INSTRUMENTS OR MECHANISMS FOR RISK MANAGEMENT PROGRAM FROM ANY AFFILIATES OR RELATED COMPANIES		February 1, 2007
		January 30, 2007	
3.1	PROVIDE DATA IN EXHIBIT K2.6 ON A STRICT CALENDAR-YEAR BASIS		
3.2	FILE ANALYSIS OF IMPACT OF MOVING RATE 1 TO REVENUE-T		
3.3	TO PROVIDE A BREAKOUT OF $16.1 MILLION AS BETWEEN UPDATED WEATHER METHODOLOGY, DECLINING AVERAGE USE, AND LOSS OF CONTRACT VOLUMES O-COST RATIO OF 1.0		
3.4	TO DETERMINE IF ANY PORTION OF ACCOUNT EXECUTIVES' COMPENSATION IS TIED TO THE ACCURACY OF THEIR FORECAST CONTRACT VOLUMES; IF ANY PORTION OF ACCOUNT EXECUTIVES' COMPENSATION IS TIED TO BEATING THEIR 2007 FORECAST OR ANY FORECAST FOR ANY YEAR		
3.5	PRODUCE FORECAST PRICE FOR 2007		
3.6	UPDATE TABLE 1 AT EXHIBIT I, TAB 2, SCHEDULE 27, PAGE 2		
3.7	TO ADVISE THE IMPACT OF A ONE PERCENT CHANGE IN THE PRICE OF GENERAL SERVICE VOLUMES		

J	Undertakings	Hearing Date	Response Filed
3.8	TO PROVIDE A PRICE PER M^3 THAT CORRESPONDS TO THE 8.5 PERCENT UNDER THE 2007		
3.9	ADD THREE COLUMNS TO TABLE 4 ACTUAL THROUGHPUT VOLUMES; WEATHER NORMALIZED THROUGHPUT VOLUMES; BOARD-APPROVED THROUGHPUT VOLUMES		
3.10	TO PROVIDE ADJUSTED R-SQUARE VALUES FOR MODELS DESCRIBED IN TABLE 6 OF EXHIBIT C2, TAB 4, SCHEDULE 1		
		February 1, 2007	
4.1	CONFIRM THAT WHEN APPLIED TO THE 2007 REVENUE REQUIREMENT, THE DIFFERENCE BETWEEN DE BEVER WEATHER METHODOLOGY AND 20-YEAR TREND METHODOLOGY IS $21.2 MILLION		
4.2	PORTION, IN DOLLARS, OF THE $21.2 MILLION IMPACT BETWEEN EXISTING AND PROPOSED METHODOLOGY THAT IS RATE 1 AND PROPORTION THAT IS RATE 6		
4.3	PRODUCE THE TREND LINE ON ACTUAL DATA FROM 1965 TO 2007 FOR ALL THREE REGIONS		
4.4	PROVIDE A VERSION OF K4.5, EXCLUDING THE DE BEVER, DE BEVER WITH TREND AND ENERGY PROBE METHODS, STARTING FROM THE YEAR 1976		
4.5	PROVIDE 20-YEAR DATA SET THAT TRACKS VARIATIONS FROM ACTUAL TO BOARD-APPROVED EACH YEAR FOR DEGREE DAYS AND FOR ROE		
4.6	REQUEST TO PROVIDE A TREND FORECAST FOR THE PERIOD 2007 TO 2012 AS A SIX-YEAR PERIOD USING THE PREVIOUS 30 SIX-YEAR PERIODS AS THE DATA SET		
4.7	UPDATE COLUMN 6 USING UPDATES TO COLUMN 7, WITH RESPECT TO REAL RESIDENTIAL NATURAL GAS PRICES FOR 2007 AND 2006, ON TABLE 2, UPDATES, TRY AND UPDATE A PROXY NUMBER FOR TABLE 3, GAS PRICES, WHICH CURRENTLY IS AT 48.6 OR NEGATIVE 48.6, WHICH APPEARS AT EXHIBIT C1, TAB 3, SCHEDULE 1, PAGE 8 OF 18		
4.8	PROVIDE EXPLANATION FOR THE DIFFERENCE IN THE REAL COMMERCIAL NATURAL GAS PRICE INCREASE IN 2007 AND 2008 AS COMPARED TO THE REAL RESIDENTIAL PRICE INCREASE		
4.9	TO PROVIDE THE PROBABILITY FIGURES ASSOCIATED WITH THE THREE VARIABLES THAT HAVE T STATISTICS ON PAGES 13 AND 14 OF EXHIBIT K4.6		
4.10	PROVIDE NORMALIZED 2006 NUMBERS, VOLUMES, SIMILAR TO TABLE 1 ON PAGE 25 OF 65 FOR AS MANY MONTHS OF ACTUALS AS AVAILABLE FOR 2006		

K2.1

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%?

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

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.

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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.

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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

Sch. 4
K2.3
M1.9

Risk Management Impact on WACOG & PGVA

Union Gas

Effective Date	Alberta Border Reference Price: 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)	PGVA Activity: Actual PGVA Deferral Activity ($millions) (C)	PGVA Deferral Activity if No Risk Management ($millions) (D)	Actual Versus No Risk Management (C vs D)	Risk Management Impact on PGVA Clearing: 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

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**		

[illegible] 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

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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

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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

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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]

[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.

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 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 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)

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

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

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

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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

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

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

Ipsos Reid

Enbridge Gas Distribution

Customer Threshold for Gas Supply Volatility Study

December 2004

ENBRIDGE

CR-374

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Ipsos Reid

Study Background

Overview of Objectives

- Ipsos-Reid was commissioned by Enbridge Gas Distribution ("EGD") to conduct quantitative survey research for residential (rate 1) and small commercial[1] (rate 6) customers to understand their sensitivity to price volatility and related issues. The specific objectives of the research were to:
  - Assess customers' level of knowledge, understanding and expectations about gas pricing and EGD'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 administering bill adjustments

[1] "Small Commercial" includes commercial, industrial, institutional and multi-residential customers with an annual natural gas consumption of <= 75,000 m^3.

Methodology

- A total of 1200 telephone interviews (computer assisted telephone interviewing) were conducted among 800 residential (rate 1) customers and 400 small commercial (rate 6) customers.
  - With a sample size of 800, results are considered accurate to within +/- 3.5%, at a 95% confidence level.
  - With a sample size of 400, results are considered accurate to within +/- 4.9%, at a 95% confidence level.
- Interviews were conducted between November 22nd and December 7th, 2004.
- Respondents were screened to ensure the interview was conducted with the person in the household or business that was responsible for making decisions regarding energy-related products and services and paying the monthly natural gas bill.
- Based on Enbridge Gas Distribution's records,
  - Of the 800 residential customers interviewed, 382 were system gas customers and 418 were direct purchase customers,
  - Of the 400 commercial customer interviewed, 193 were system gas customers and 207 were direct purchase small commercial customers.

Methodology Cont'd…

- The reporting of the results focuses on:
  - All customers (combined residential and small commercial responses)
  - Residential versus small commercial
- Some results are also presented based on customers' awareness of their natural gas commodity supplier:
  - System Gas ("SG") Actual: System Gas customers who are aware that they purchase their natural gas commodity from Enbridge
  - Direct Purchase ("DP") Actual: Direct Purchase customers who are aware that they purchase their natural gas commodity from a broker
  - Direct Purchase ("DP") – System Gas Perceived: Direct Purchase customers who believe they purchase their natural gas commodity from Enbridge
  - System Gas – Direct Purchase ("DP") Perceived: System Gas customers who believe they purchase their natural gas commodity from a broker

Note: The sums of the individual response categories may not add to 100% due the effect of rounding.

Executive Summary

Executive Summary

Understanding and Perceptions of Natural Gas Pricing

- While the majority of system gas customers are aware that they purchase their natural gas commodity from Enbridge Gas Distribution (90%), nearly three-in-five direct purchase customers (58%) continue to believe they purchase their natural gas commodity from Enbridge.
- Three-quarters of customers (75%) expect the market price for the natural gas commodity will increase over the next year.
- Sixteen percent of all customers (13% of residential and 22% of small commercial customers) believe that utilities like Enbridge have the most responsibility when dealing with issues related to natural gas pricing.
- More than four-in-five of all customers (83%) believe that Enbridge makes a profit from the price charged for the supply of the natural gas commodity.
- More than one-third of all customers (35%) think that the market price that Enbridge pays for the natural gas commodity it buys remains stable over the year.
- According to just over one-half of all respondents (54%), Enbridge should purchase the natural gas commodity at a fixed price instead of a floating rate.
  - Direct Purchase customers (56%) are somewhat more likely than System Gas customers (47%) to say that the company should purchase natural gas at a fixed rate.

Executive Summary Cont'd…

Sensitivity to Price Volatility

- 57% of all customers think it is more important to maintain a steady price than to obtain the lowest price.
  - Somewhat more small commercial than residential customers believe it is more important to maintain a steady price than to obtain the lowest price (62% vs. 55%).
  - Direct purchase customers are more likely than system gas customers to find a steady price to be most important (63% DP Actual versus 51% SG Actual).
- Customer expectations about the future of natural gas prices seem to affect their sensitivity to price volatility. Customers that expect the market price for natural gas to increase over the next year are more likely to:
  - prefer that Enbridge purchase natural gas at a fixed rate (56% versus 41% for customers who expect a price decrease)
  - believe that maintaining a steady price is more important than obtaining the lowest price (58% versus 35% for customers who expect a price decrease).
- Only one-half (50%) of customers report noticing a bill adjustment made to their bill in the past year.
  - More small commercial than residential customers have noticed the adjustments (54% versus 48%).

Executive Summary Cont'd…

Sensitivity to Price Volatility Cont'd

- For all customers, as the amount of the bill adjustment increases, there is a reduced willingness to accept price fluctuations.
  - However, even at the highest level tested ($100), nearly one-half of customers (48%) reported they would be very or somewhat willing to have the commodity portion of their bill fluctuate by this amount in any one year (period of time).
    - Small commercial customers are somewhat more willing to accept a fluctuation of $100 than are residential customers (52% versus 46% very/somewhat willing).
  - At the $75 level, almost three-in-five of all customers are willing to have the commodity portion of their bill fluctuate by this amount (56% very/somewhat willing).
  - At the lowest levels tested, the majority of all customers are willing to accept the fluctuation on their bill (78% very/somewhat willing at $25; 68% very/somewhat willing at $50).
  - There is little variation in customers' willingness to accept bill fluctuations at the levels tested among type of customer (DP or SG) or supplier awareness..

Executive Summary Cont'd…

Adjustment Frequency Preferences

- In general, about six-in-ten of all customers (58%) would prefer that Enbridge make smaller, more frequent adjustments to their bill, and four-in-ten of all customers (40%) would prefer a one-time, year-end adjustment.
  - More small commercial than residential customers prefer smaller, more frequent adjustments (63% versus 55%).
- While the proportion of all customers who prefer frequent adjustments increases as the amount of the debit/credit increases, more of all customers prefer frequent adjustments under the refund scenario than the payment scenario at all adjustment levels.
  - Under the payment scenario, small commercial customers are significantly more likely to prefer a one-time adjustment than residential customers at each level tested.

Risk Management Strategy Preferences

- When no price point is attached to the question, the risk management strategy preferences of all customers rank as follows:
  - creating a high and low limit around the current price (33%)
  - purchase insurance (26%),
  - fixing prices at current levels (25%).
  - do not manage the price risk in any way (15%)

Executive Summary Cont'd…

<u>Affect of Price Decrease on Strategy Preference</u>

- When presented with a scenario of a 50% price decrease, nearly two-thirds of all respondents (64%) who originally stated a preference for Enbridge to fix prices at current levels indicated the scenario would change their response.
- Almost one-half (45%) of these chose a new strategy that allowed them some benefit from falling prices (7% of all respondents; 29% of those who originally selected the strategy).
- Seven percent of those who originally chose an approach that afforded some protection from increasing prices now opted for Enbridge to NOT manage the price risk in any way.

<u>Affect of Price Decrease on Strategy Preference</u>

- When presented with a scenario of a 50% price *increase*, less than one-third (32%) of all customers who initially preferred that Enbridge not manage the price risk indicated the scenario would change their response.
- Six-in-ten (60%) of these chose a new approach that afforded some protection from increasing prices (3% of all respondents; 19% of those who originally selected the strategy).

Recommendations

- Any issue related to “price” represents a very special challenge to Enbridge:
  - Residential and small business consumers think that the price they pay for the commodity will continue to rise
  - Consumers ultimately associate pricing issues with the utility and government
  - And consumers are generally confused on related issues such as who is profiting, what the regulatory environment is, etc.
- In this environment opinion is more divided than polarized one way or the other on options/ideas for preferences and actions on price-related issues:,
  - Fixed and steady tend to win out over floating and lowest in defining consumer preferences, although opinion is divided
  - One-time wins out over more frequent in terms of general adjustment frequency preferences when the potential refund or payment are at lower levels, while more frequent wins out over one-time as the payment/refund levels increase (especially in the case of a payment)
  - The vast majority of consumers want Enbridge to execute some kind of strategy to help manage the potential risk for large fluctuations in commodity prices; however preference is split between fixing prices at current levels, purchasing insurance or creating a high/low price band around the current price

Recommendations Cont'd…

- This suggests that there is a consumer environment:
  - With potential for skepticism about any changes that Enbridge might introduce on "pricing issues"
  - Regardless of any changes made, there is a sizeable proportion of consumers who will be more receptive and a sizeable proportion of consumers who will be less receptive to any change
    - With this in mind, if the basic principle used by Enbridge in making some of its strategic decisions is that "the majority rules," then the study results suggest that:
      - $75 represents the cut-off in terms of acceptable fluctuation in the commodity portion of consumers' bills among residential customers, and
      - $100 is the level among commercial customers.

Prices and Regulation

Natural Gas Supplier Awareness

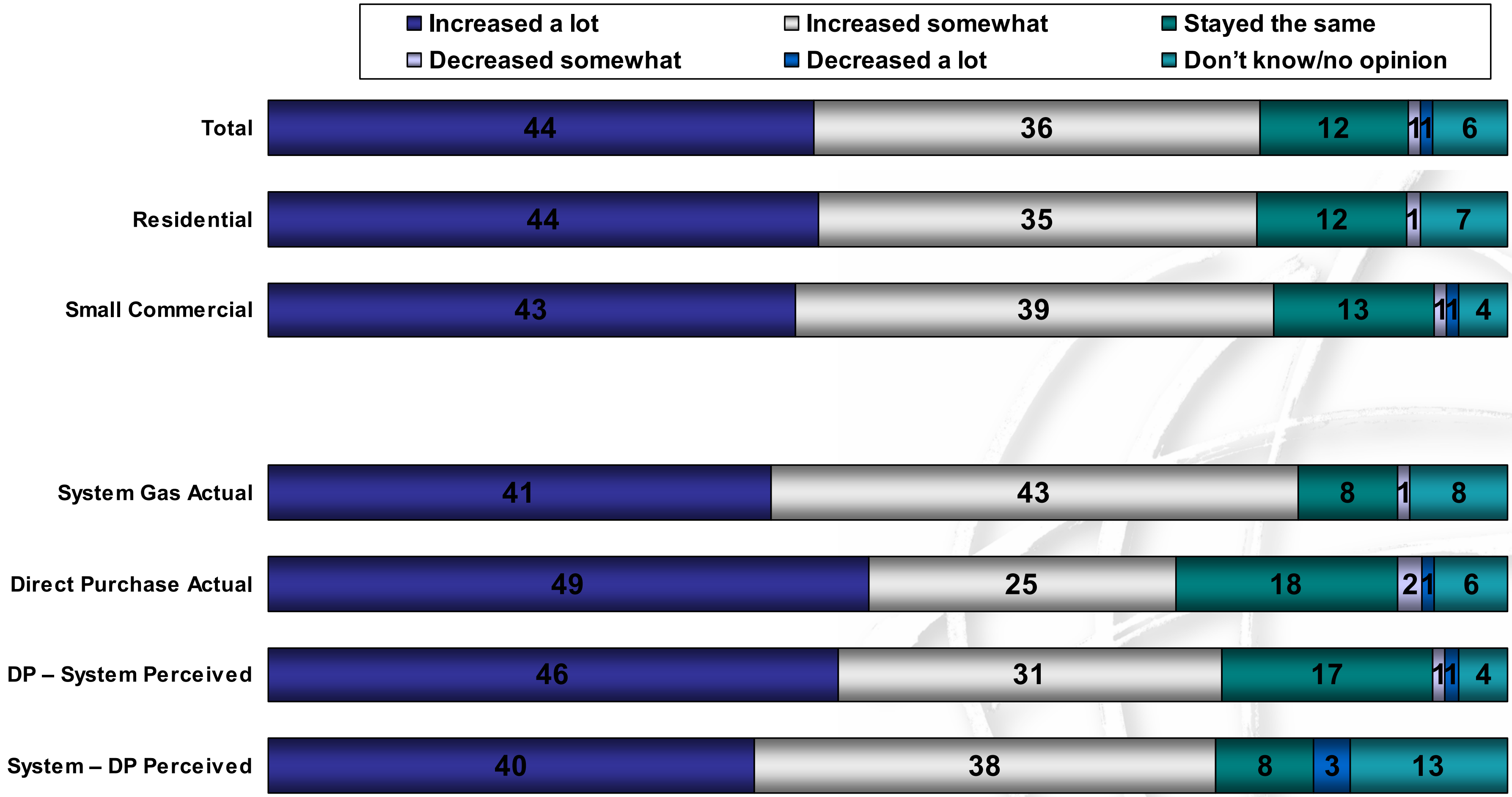
- Nearly six-in-ten (58%) direct purchase customers continue to believe that they purchase their natural gas commodity from Enbridge Gas Distribution. Less than a third (32%) are aware that they are direct purchase customers.
- Comparatively, the majority (90%) of system gas customers identified Enbridge as their supplier.
- Residential and Small Commercial customers are equally as likely to be able to identify if they are system or direct purchase gas customers.

	System Gas Customers	**Direct Purchase Customers**
N=	574	625
Enbridge (System Gas)	*90*	*58*
Direct Purchase Net	*7*	*32*
Direct Energy	5	23
Ontario Energy Savings Corporation	1	5
Gas Marketer (unknown)	1	3
Superior	-	1
Other	1	3
Don’t know	2	7

Q1. Who do you purchase your natural gas commodity from?

Perceptions of the Market Price of Natural Gas

Four-in-five customers believe that the market price for the natural gas commodity has increased over the past two years (80% increased a lot/somewhat) and one-in-ten believe it has stayed the same (12%). These results are consistent for both residential and small commercial customers. However, System Gas customers (84%) are somewhat more likely to believe the price has increased than are Direct Purchase customers (74%).



Q2. Thinking specifically about the market price for the natural gas commodity, over the past two years, would you say the price has increased a lot, increased somewhat, stayed the same, decreased somewhat, or decreased a lot?

Perceptions of the Future of Natural Gas Prices

In addition, three-quarters of customers (75%) expect the market price for the natural gas commodity will increase over the next year and another one-in-five (17%) think it will stay the same.

Q3. And, over the next year, do you think the market price for the natural gas commodity will increase, decrease or stay the same?

Natural Gas Market Price Influencers

According to customers, the greatest impacts influencing the price for natural gas commodity are: world energy prices (18%), supply and demand (18%), availability (11%) and world events (10%).

	Total	Residential	Small Commercial
N=	1200	800	400
World energy prices	18	19	18
Supply and demand	18	17	19
Availability (supply) of natural gas	11	12	10
World events	10	8	12
High profits (greed, etc.)	7	8	6
Production/ distribution/ labour cost	7	6	8
More government control/ intervention/ regulation	6	7	5
Economy	4	3	5
Variations in climate	4	3	4
Don't know	19	18	21

Q4. What do you think would have the greatest impact on influencing the price that you pay for the natural gas commodity, that is the supply of natural gas that you use?

Responsibility for Natural Gas Price Issues

• Enbridge customers think that officials from the federal (22%) and provincial (20%) government have the most responsibility for dealing with issues associated with natural gas prices, followed by utilities (16%).
• Proportionately more small commercial customers than residential believe that utilities have the most responsibility when dealing with these issues (22% versus 13%).

	Total	Residential	Small Commercial
N=	1200	800	400
Officials from the federal government	22	22	24
Officials from the provincial government	20	22	17
Utilities like Enbridge Gas Distribution	16	13	22
Natural Gas marketers	7	8	5
Ontario Energy Board	5	5	4
Government / politicians (unspecified)	3	3	3
Customers/me/myself	3	3	2
Don't know	15	15	15

Q7. Who do you think has the most responsibility for dealing with issues associated with natural gas prices?

Regulatory Process for Distribution Rates

- Nearly six-in-ten customers (58%) agree that the Ontario government's regulatory process for setting approving distribution rates ensures fair and reasonable prices for natural gas.
- Residential customers are less likely to agree with this than are small commercial customers (56% versus 63%).

	Total	Residential	Small Commercial	System Gas Actual	Direct Purchase Actual	DP – System Perceived	System – DP Perceived
N=	1200	800	400	518	199	363	40
Top 2 Box %	*58*	56	63	*58*	*53*	*58*	*78*
Strongly agree	10	10	11	10	11	10	13
Somewhat agree	48	45	53	48	42	48	65
Somewhat disagree	17	17	18	17	18	18	13
Strongly disagree	19	20	16	19	22	19	10
Don't know	6	7	3	6	8	5	-

Q8. Do you agree or disagree that the Ontario government's regulatory process for setting and approving distribution rates ensures fair and reasonable prices for natural gas?

Ipsos Reid

Understanding of Natural Gas Pricing

- More than four-in-five customers (83%) believe that Enbridge makes a profit from the price charged for the supply of the natural gas commodity.
- Only about three-in-five (59%) think that the prices that Enbridge charges for delivering natural gas are regulated.

	Total	Residential	Small Commercial	System Gas Actual	Direct Purchase Actual	DP – System Perceived	System – DP Perceived
N=	1200	800	400	518	199	363	40
Does Enbridge make a profit from supply?							
Yes	83	82	86	83	81	87	73
No	11	11	10	12	11	8	23
Don't know	6	6	5	5	8	5	5
Are natural gas delivery prices regulated?							
Yes	59	59	59	57	57	63	55
No	21	18	27	20	21	22	30
Don't know	20	23	14	22	22	16	15

Q5. And, as far as you know, does Enbridge make a profit from the price they charge for the supply of the natural gas commodity, that is the actual gas you use?
Q6. Are the prices that Enbridge charges for delivering natural gas to your home regulated?

Understanding of Natural Gas Pricing Cont'd...

- More than one-half of both residential and small commercial customers think that the market price that Enbridge pays for the natural gas commodity it buys changes frequently over the year (57% and 53% respectively).
- System Gas customers are somewhat more likely to think that the price changes as compared to Direct Purchase customers (59% versus 55%).

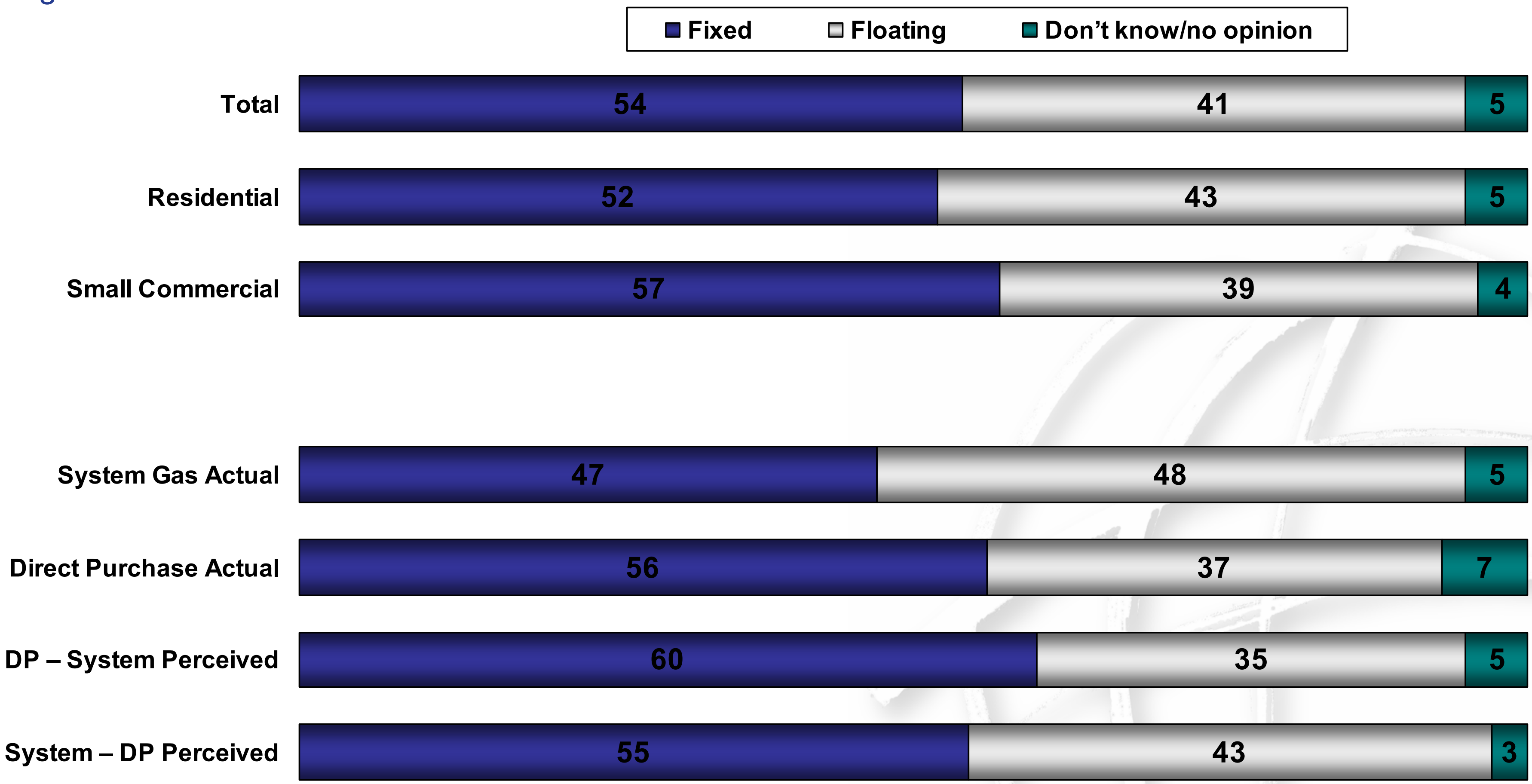
	Total	Residential	Small Commercial	System Gas Actual	Direct Purchase Actual	DP – System Perceived	System – DP Perceived
N=	1200	800	400	518	199	363	40
Does the price Enbridge pays for natural gas change?							
Changes	56	57	53	59	55	49	73
Stable	35	32	41	32	35	41	28
Don't know	9	11	7	9	11	10	-
How frequently does Enbridge set rates customers pay for natural gas?							
Every month	17	19	15	18	16	18	18
Every 3-4 months	31	31	32	33	26	30	33
Twice a year	22	21	25	25	24	18	20
Once a year	20	19	21	17	20	23	23
Don't know	10	11	8	7	15	12	8

Q9. Do you think the market price that Enbridge Gas Distribution pays to the companies from which it buys the natural gas commodity changes frequently over the year, or do they pay a stable price over the year?
Q10. Based on what you know or think is the case, how frequently does Enbridge review and set the rates that customers pay for the natural gas commodity on the bill

Sensitivity to Price Volatility

Fixed Price Versus Floating Rate

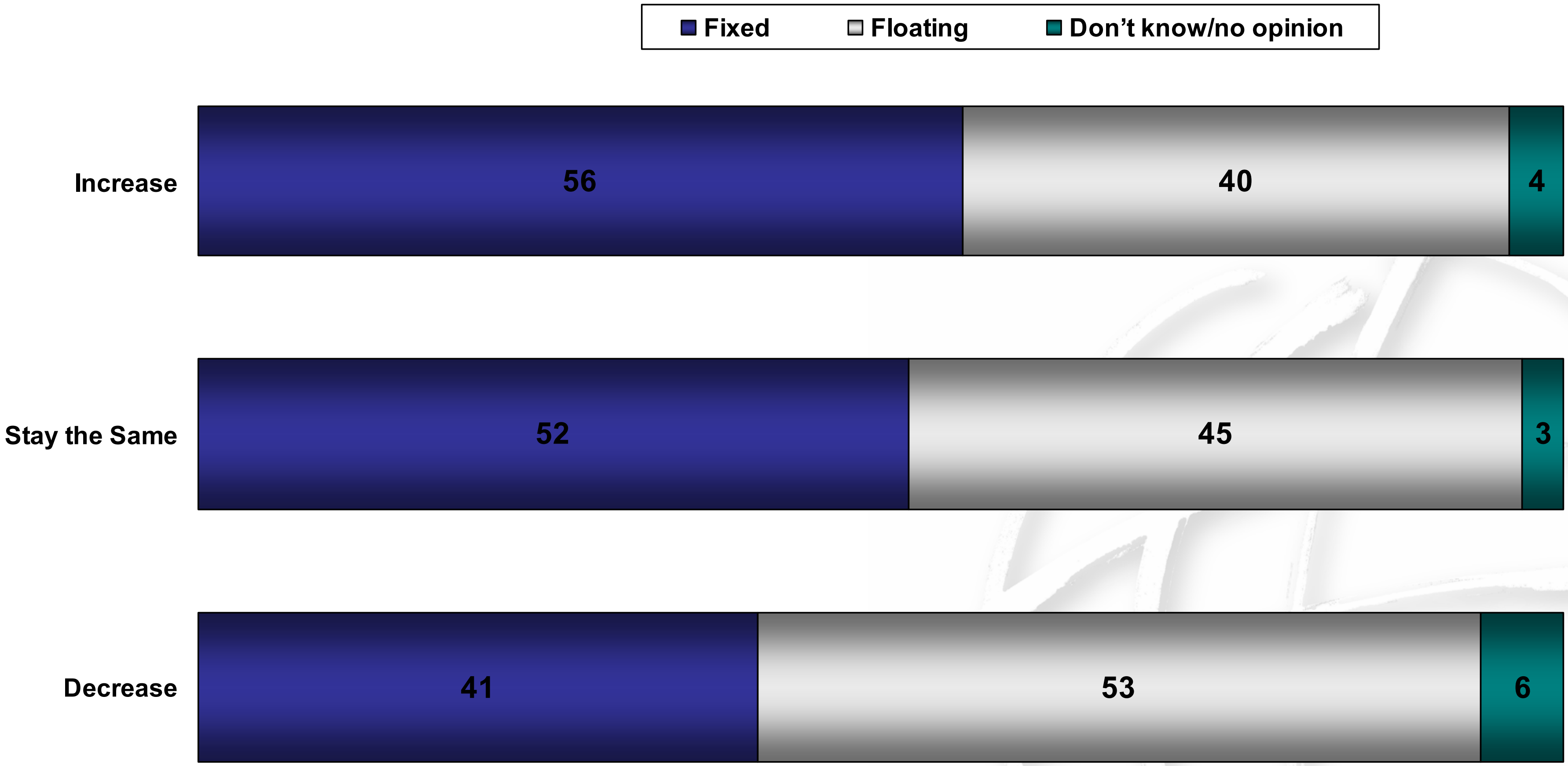
When asked whether Enbridge should purchase the natural gas commodity at a fixed price or at a floating rate, just over one-half of respondents (54%) said a fixed rate. Direct Purchase customers (56%) are somewhat more likely than System Gas customers (47%) to say that the company should purchase natural gas at a fixed rate.



Q11. Do you think the company should purchase the natural gas commodity at a *fixed* *price with stable pricing but not necessarily the lowest price or do you think they should purchase the natural gas commodity at a* *floating* *rate which can lead to a lower price but also runs the risk of having to pay higher prices?*

Fixed Price Versus Floating Rate And Perceptions of the Future of Natural Gas Prices

Customers that indicated they expect the market price for the natural gas commodity to increase over the next year are more likely to prefer that Enbridge purchase natural gas at a fixed rate than are customers who expect the price to decrease.



Q11. Do you think the company should purchase the natural gas commodity at a fixed price with stable pricing but not necessarily the lowest price or do you think they should purchase the natural gas commodity at a floating rate which can lead to a lower price but also runs the risk of having to pay higher prices?

Reasons for a Fixed Rate

More small commercial than residential customers state that the main reason for wanting Enbridge to purchase natural gas at a fixed rate is for stable prices with no fluctuations (57% small commercial customers and 47% residential) and for the ability to budget (24% versus 14%).

Base: Respondents who said fixed rate at Q11	Total	Residential	Small Commercial
N=	644	417	227
Stability of pricing/ no fluctuations/ no changes in prices	50	47	57
Customers know what they are paying	24	23	25
Ability to budget	18	14	24
Protects you from increasing prices	9	10	7
Able to take advantage of lower prices/ benefit from lower prices/ best price advantage	8	8	8
Consistency in our bill	6	7	4
More fair	4	3	5
Don't know	3	3	2

Q12. And, why do you think they should purchase the natural gas commodity at a fixed rate?

Reasons for a Floating Rate

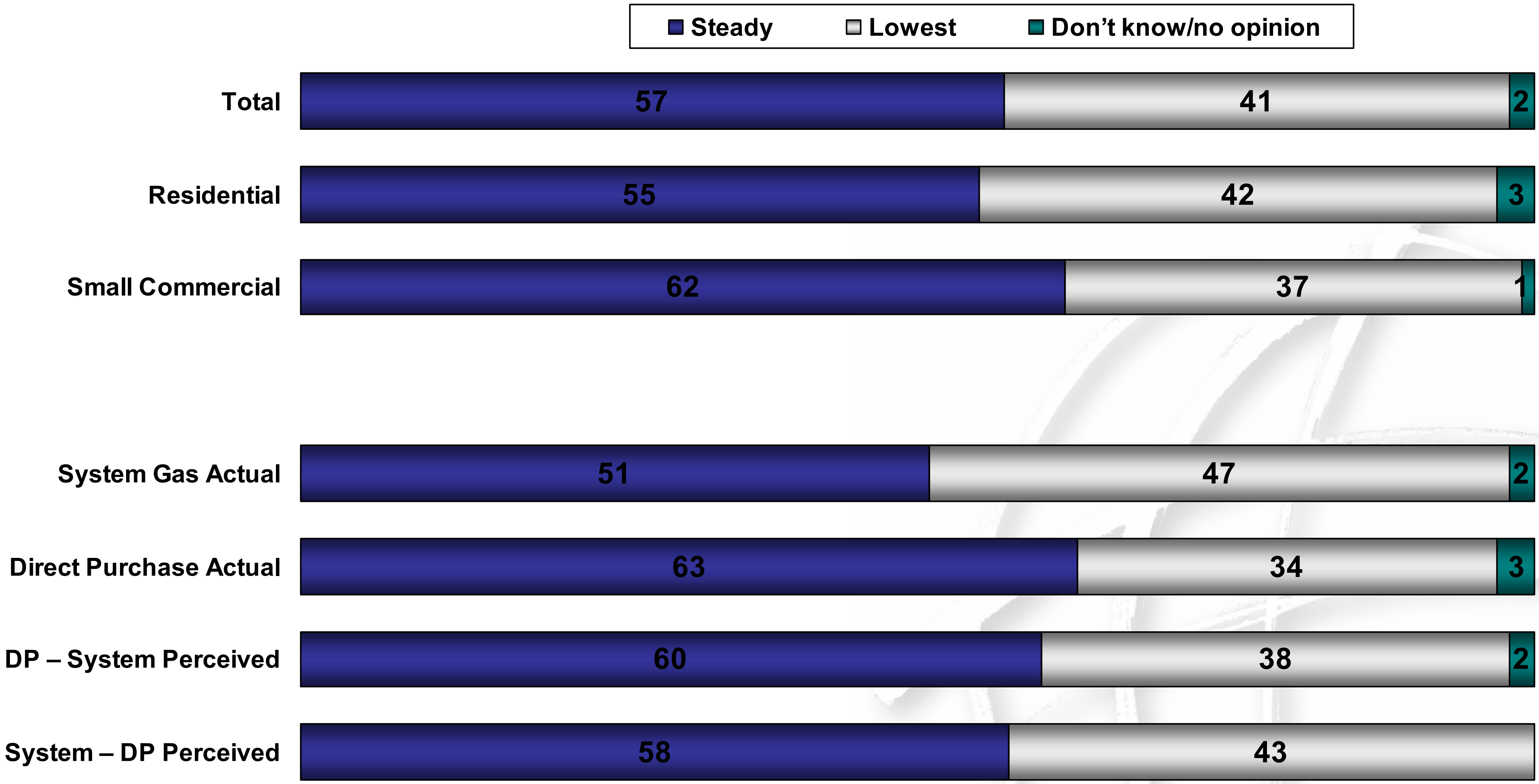
The main reason provided for wanting Enbridge to purchase natural gas at a floating rate is to take advantage of lower prices (28%).

Base: Respondents who said floating rate at Q11	Total	Residential	Small Commercial
N=	497	340	157
To take advantage/ benefit from lower prices	28	28	30
Supply and Demand	17	16	20
Gas prices might go down	13	13	13
The prices are always changing	11	13	9
Stability of pricing/ no fluctuations	7	8	6
The consumer might miss out on cheaper prices	7	8	6
Long term benefit	7	5	10
More fair	6	6	6
Reflects actual cost	5	4	6
Protects you from increasing prices	4	5	3
Can make alternative decision/ option	4	4	4

Q12. And, why do you think they should purchase the natural gas commodity at a floating rate?

Steady Price Versus Lowest Price

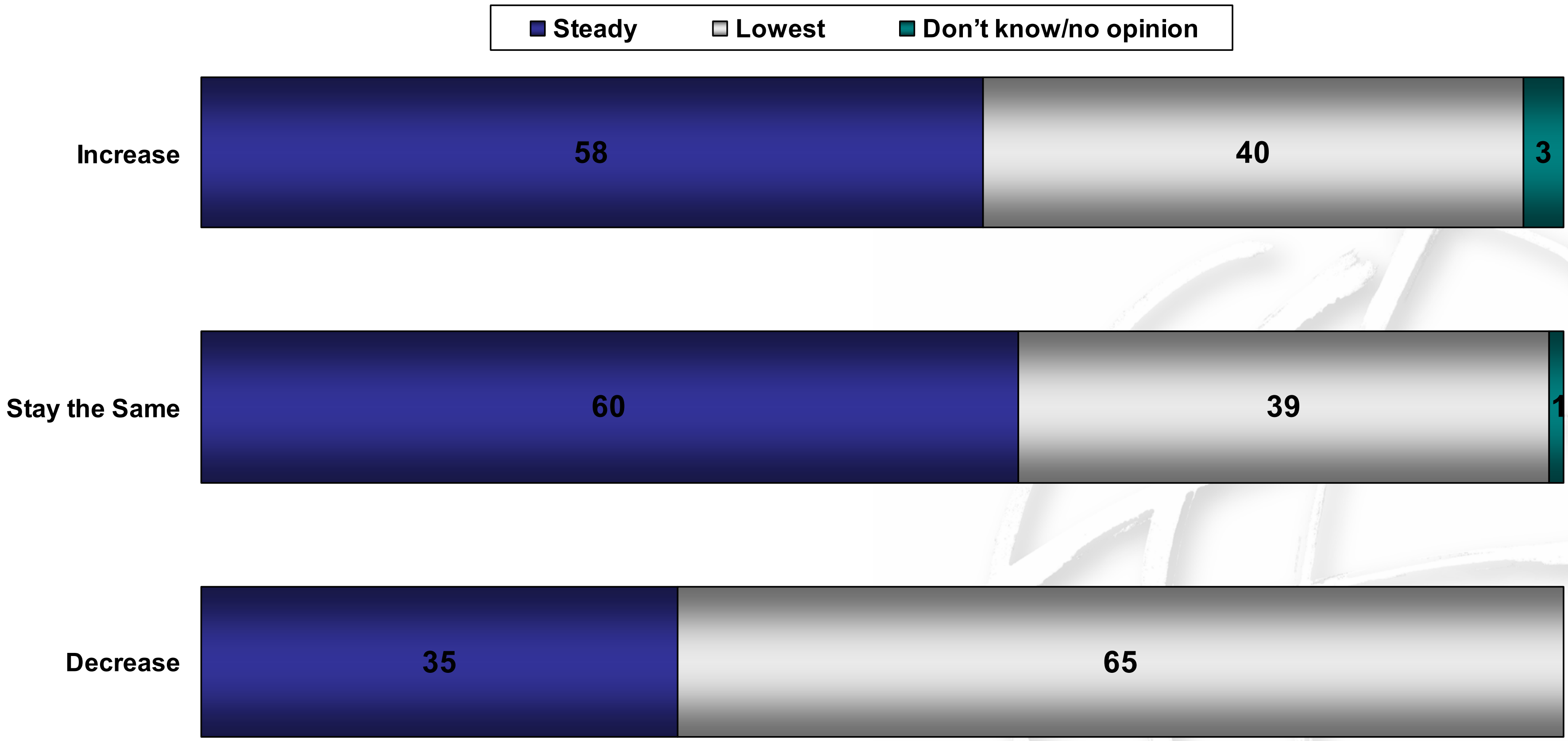
It is more important to maintain a steady price than to try to obtain the lowest price for more than six-in-ten (62%) small commercial customers, somewhat more than residential customers (55%).



Q13. What is more important to you, maintaining a steady price for the natural gas commodity, which may or may not be higher than the market rate or trying to find the lowest price for natural gas commodity even if its means the price will fluctuate more frequently and could result in higher prices?

Steady Price Versus Lowest Price And Perceptions of the Future of Natural Gas Prices

Maintaining a steady price is more important than obtaining the lowest price for significantly more customers who expect the market price of natural gas to increase in the next year than those who expect it to decrease (58% versus 35%).



Q13. What is more important to you, maintaining a steady price for the natural gas commodity, which may or may not be higher than the market rate or trying to find the lowest price for natural gas commodity even if its means the price will fluctuate more frequently and could result in higher prices?

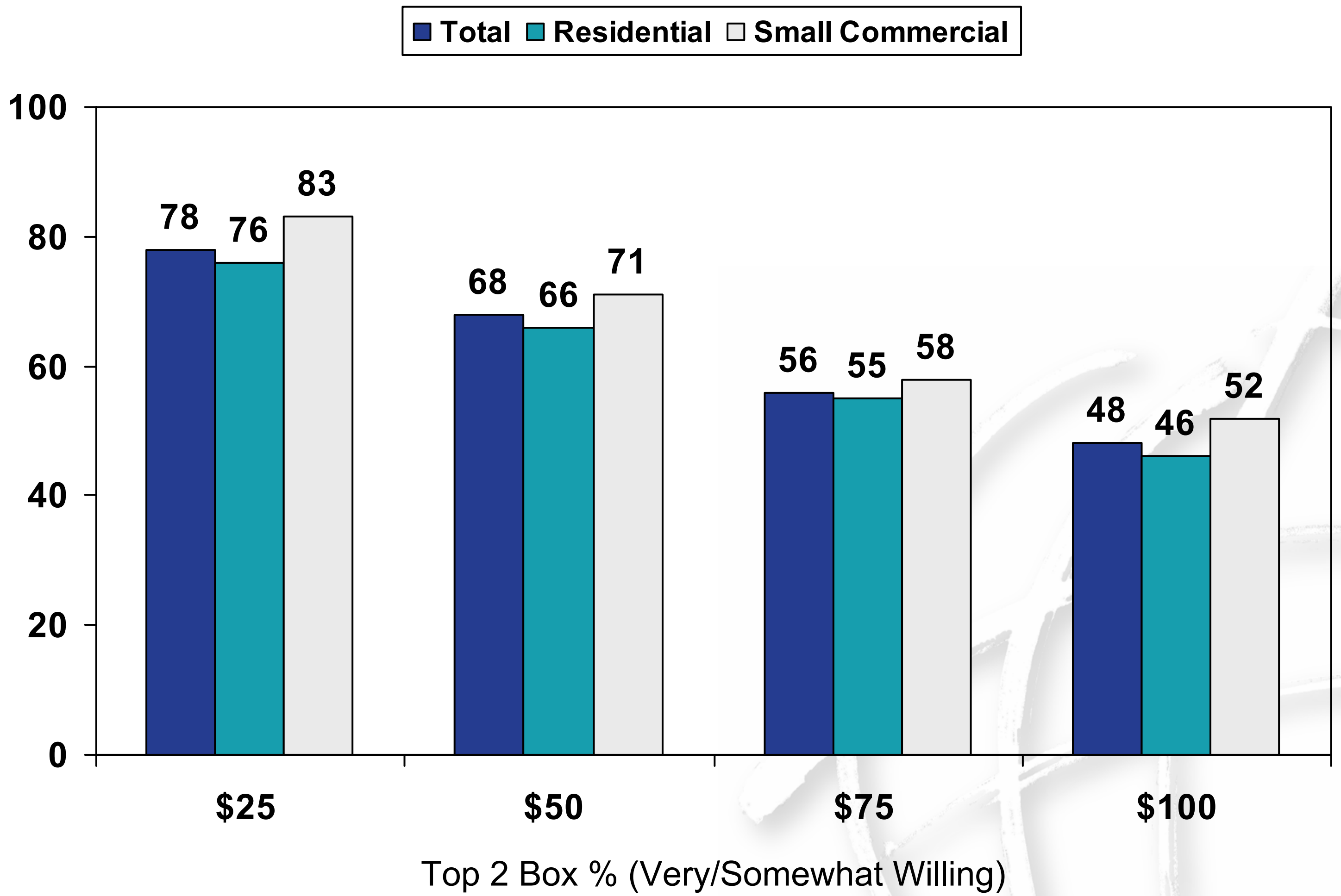
Willingness for Bill Fluctuation

Customers are less willing to accept price fluctuations as the amount of the bill adjustment increases. This is true of both residential and small commercial customers. At the highest level tested ($100), nearly one-half of all customers (48%) reported they would be very or somewhat willing to have the commodity portion of their annual natural gas bill fluctuate by this amount. Small commercial customers are somewhat more willing to accept a fluctuation of $100 than are residential customers (52% versus 46% very/somewhat willing).

	Total				Residential				Small Commercial			
	$25	$50	$75	$100	$25	$50	$75	$100	$25	$50	$75	$100
Net Willing (Top 2 Box %)	78	68	56	48	76	66	55	46	83	71	58	52
Very willing	37	27	18	14	34	24	15	12	42	31	23	17
Somewhat willing	42	41	38	34	42	42	40	33	41	40	36	35
Not very willing	8	14	17	18	9	14	16	18	7	16	19	17
Not at all willing	11	16	25	32	12	18	26	34	8	11	23	30
Don’t know	3	2	2	2	3	2	3	3	2	2	1	1

Q19. Would you be very willing, somewhat willing, not very willing, or not at all willing to have the commodity portion of your annual natural gas bill fluctuate by a maximum of [INSERT ITEM]?

Willingness for Bill Fluctuation



Q19. Would you be very willing, somewhat willing, not very willing, or not at all willing to have the commodity portion of your annual natural gas bill fluctuate by a maximum of [INSERT ITEM]?

Willingness for Bill Fluctuation – System vs. Direct Purchase

Willingness to accept the various bill fluctuations does not vary by customer type (system or direct purchase) or customers' awareness of their supplier.

	System Gas Actual				Direct Purchase Actual				DP - System Perceived				System - DP Perceived			
	$25	$50	$75	$100	$25	$50	$75	$100	$25	$50	$75	$100	$25	$50	$75	$100
Net Willing (Top 2 Box %)	*77*	*67*	*56*	*48*	*77*	*69*	*55*	*46*	*79*	*69*	*56*	*47*	*90*	*73*	*63*	*50*
Very willing	34	26	17	14	35	23	15	14	38	28	19	13	53	38	28	15
Somewhat willing	43	41	39	34	42	46	40	33	41	41	37	34	38	35	35	35
Not very willing	9	15	16	18	11	14	18	19	7	12	18	19	8	15	15	18
Not at all willing	11	15	25	32	11	17	26	33	12	17	25	33	3	13	23	33
Don't know	4	3	3	3	2	1	1	2	2	1	1	1	-	-	-	-

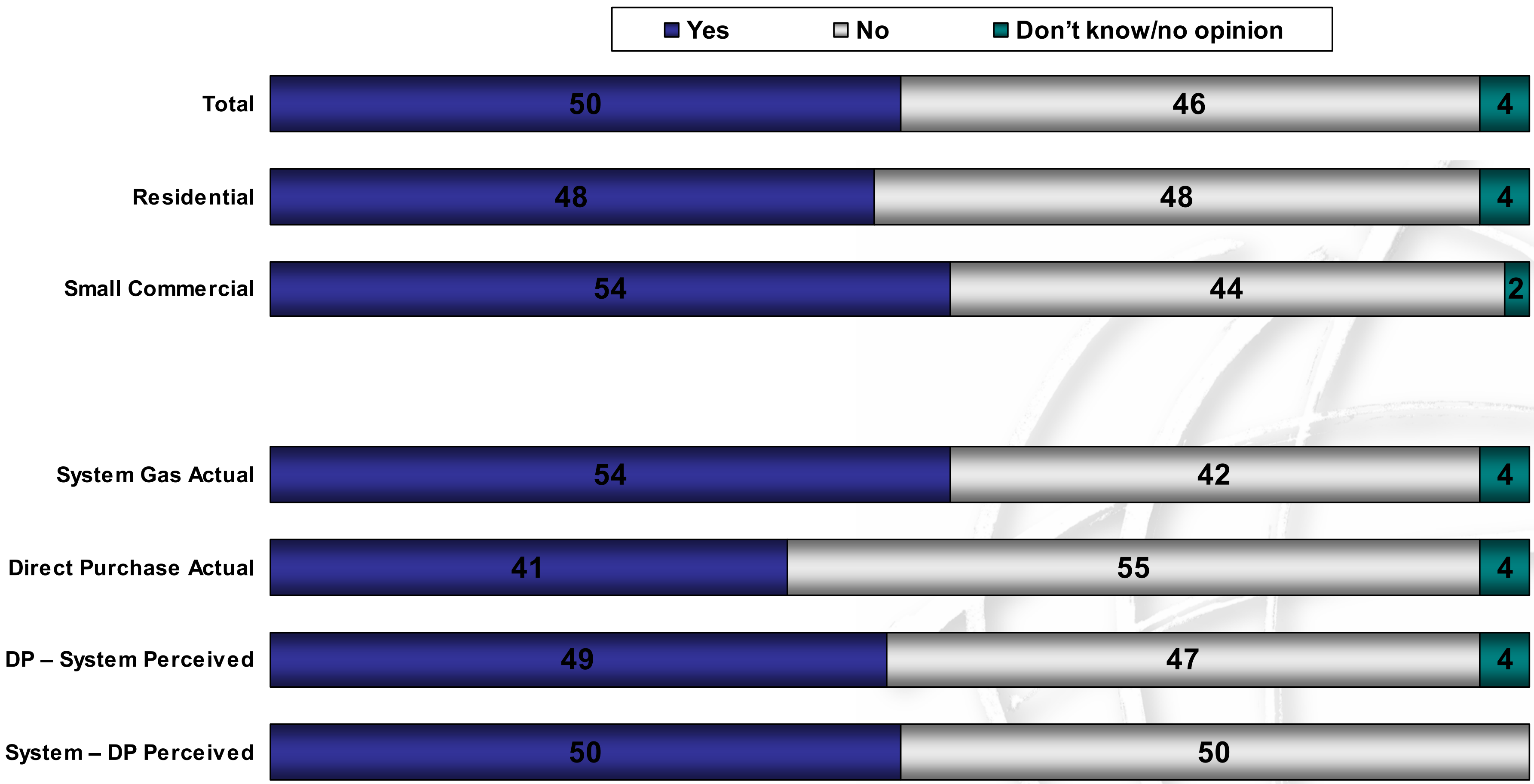
Q19. Would you be very willing, somewhat willing, not very willing, or not at all willing to have the commodity portion of your annual natural gas bill fluctuate by a maximum of [INSERT ITEM]?

Ipsos Reid

Bill Adjustment Preferences

Awareness of Bill Adjustments

- One-half (50%) of customers report noticing a bill adjustment made to their bill in the past year, with somewhat more small commercial than residential customers noticing the adjustments (54% vs. 48%).
- System gas customers are more likely to report noticing the adjustments than direct purchase customers (54% vs. 41%).

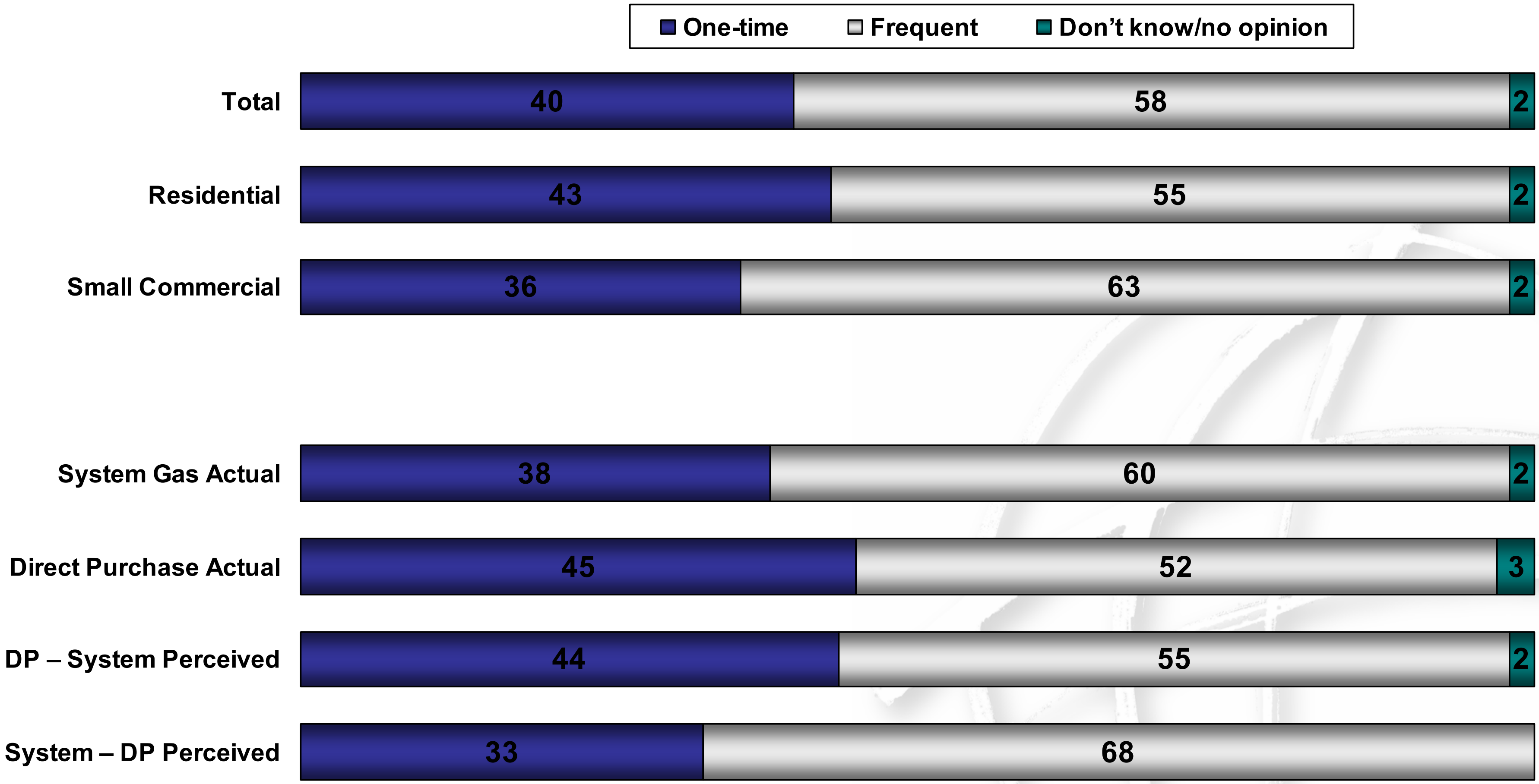


Q20. Have you noticed such an adjustment being made to your bill in the past year?

Ipsos Reid

General Preference for Frequency of Bill Adjustments

In general, about six-in-ten customers (58%) would prefer that Enbridge make smaller, more frequent adjustments to their bill, and four-in-ten (40%) would prefer a one-time, year-end adjustment. More small commercial than residential customers prefer smaller, more frequent adjustment (63% versus 55%).



Q21. Generally speaking, would you prefer that Enbridge make a one-time, year-end adjustment to your bill, or make smaller, more frequent adjustments to your bill?

Frequency of Bill Adjustments

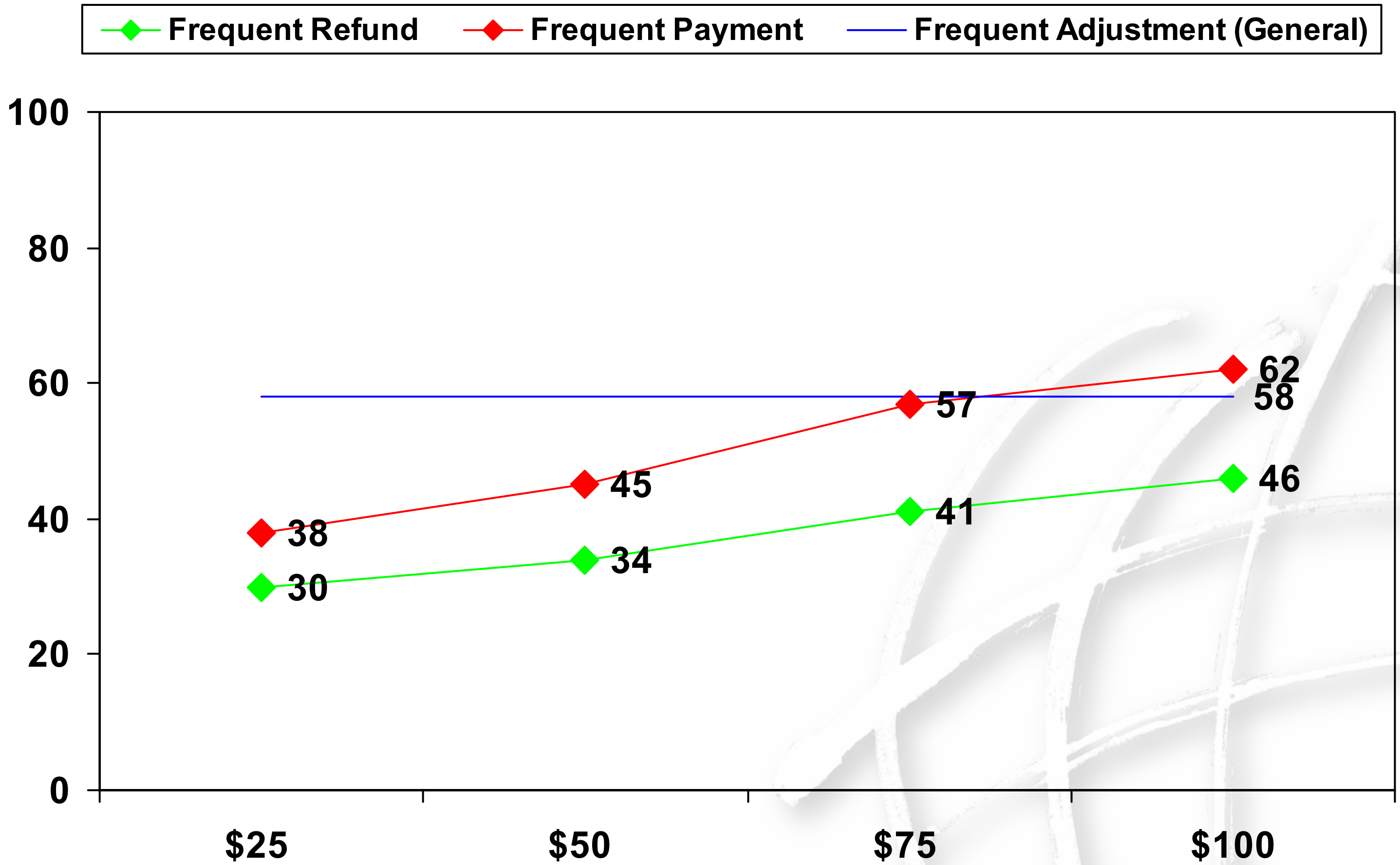
Among customers who would prefer smaller and more frequent adjustments to their bill, most think that the adjustments should be made four times per year (61%).

Base: Respondents who wanted smaller, more frequent adjustments to their bill	Total	Residential	Small Commercial	System Gas Actual	Direct Purchase Actual	DP – System Perceived	System – DP Perceived
N=	691	440	251	313	104	198	27
Twice per year	12	12	11	9	14	17	11
Four times per year	61	60	62	65	59	55	52
Once per month	27	27	27	26	27	28	37
Don't know	-	1	-	-	1	1	-

Q22. And, generally speaking, how frequently do you think Enbridge should make these adjustments to your bill?
Base: Respondents who said they wanted 'smaller, more frequent adjustments' to their bill at Q21.

Frequency of Bill Adjustments Based on Refund/Payment Scenarios

Under both the refund and payment scenarios, the proportion of customers who prefer frequent adjustments increases as the amount of the debit/credit increases. However, proportionately more customers prefer frequent adjustments under the refund scenario than the payment scenario at all adjustment levels.



Q23. If Enbridge were to make a total adjustment for the year, in the amount of [INSERT ITEM] which would be a refund to be paid to you, do you think they should adjust your bill for this amount at the end of the year or should they make smaller adjustments throughout the year?
Q24. And, if Enbridge were to make a total adjustment for the year, in the amount of [INSERT ITEM] which would be a payment to be collected from you, should they adjust your bill for this amount at the end of the year or should they make smaller adjustments throughout the year?

Frequency of Bill Adjustments Based on Refund/Payment Scenarios

- Under the refund scenario, there is little difference between residential and small commercial customers in their preference for one-time or frequent adjustments.
- Under the payment scenario, small commercial customers are significantly more likely to prefer a one-time adjustment than residential customers at each adjustment level tested.

	Total				Residential				Small Commercial			
	$25	$50	$75	$100	$25	$50	$75	$100	$25	$50	$75	$100
Refund												
One-time adjustment	68	65	57	53	67	64	57	53	71	67	58	53
More frequent adjustments	30	34	41	46	31	35	42	45	28	32	41	46
Don't know	1	1	1	1	2	1	2	1	1	1	1	1
Payment												
One-time adjustment	60	54	42	36	57	50	38	34	66	61	48	40
More frequent adjustments	38	45	57	62	41	48	60	64	33	38	51	59
Don't know	2	2	2	2	2	2	2	2	1	1	2	1

Q23. If Enbridge were to make a total adjustment for the year, in the amount of [INSERT ITEM] which would be a refund to be paid to you, do you think they should adjust your bill for this amount at the end of the year or should they make smaller adjustments throughout the year?
Q24. And, if Enbridge were to make a total adjustment for the year, in the amount of [INSERT ITEM] which would be a payment to be collected from you, should they adjust your bill for this amount at the end of the year or should they make smaller adjustments throughout the year?

Frequency of Bill Adjustments Based on Refund/Payment Scenarios

There is little variation in preference for one-time or frequent adjustments based on customer type (system or direct purchase) or awareness of supplier.

	System Gas Actual				Direct Purchase Actual				DP – System Perceived				System – DP Perceived			
	$25	$50	$75	$100	$25	$50	$75	$100	$25	$50	$75	$100	$25	$50	$75	$100
Refund																
One-time adjustment	68	64	56	51	71	65	57	55	68	66	59	56	78	75	65	63
More frequent adjustments	31	34	42	48	27	34	41	43	32	34	41	44	23	25	33	38
Don't know	2	2	2	2	2	2	2	2	1	1	1	-	-	-	3	-
Payment																
One-time adjustment	61	55	40	34	60	52	45	38	61	56	44	39	58	58	38	35
More frequent adjustments	37	43	57	64	37	45	52	59	38	44	52	60	43	43	63	65
Don't know	2	2	3	2	3	3	3	3	1	-	3	1	-	-	-	-

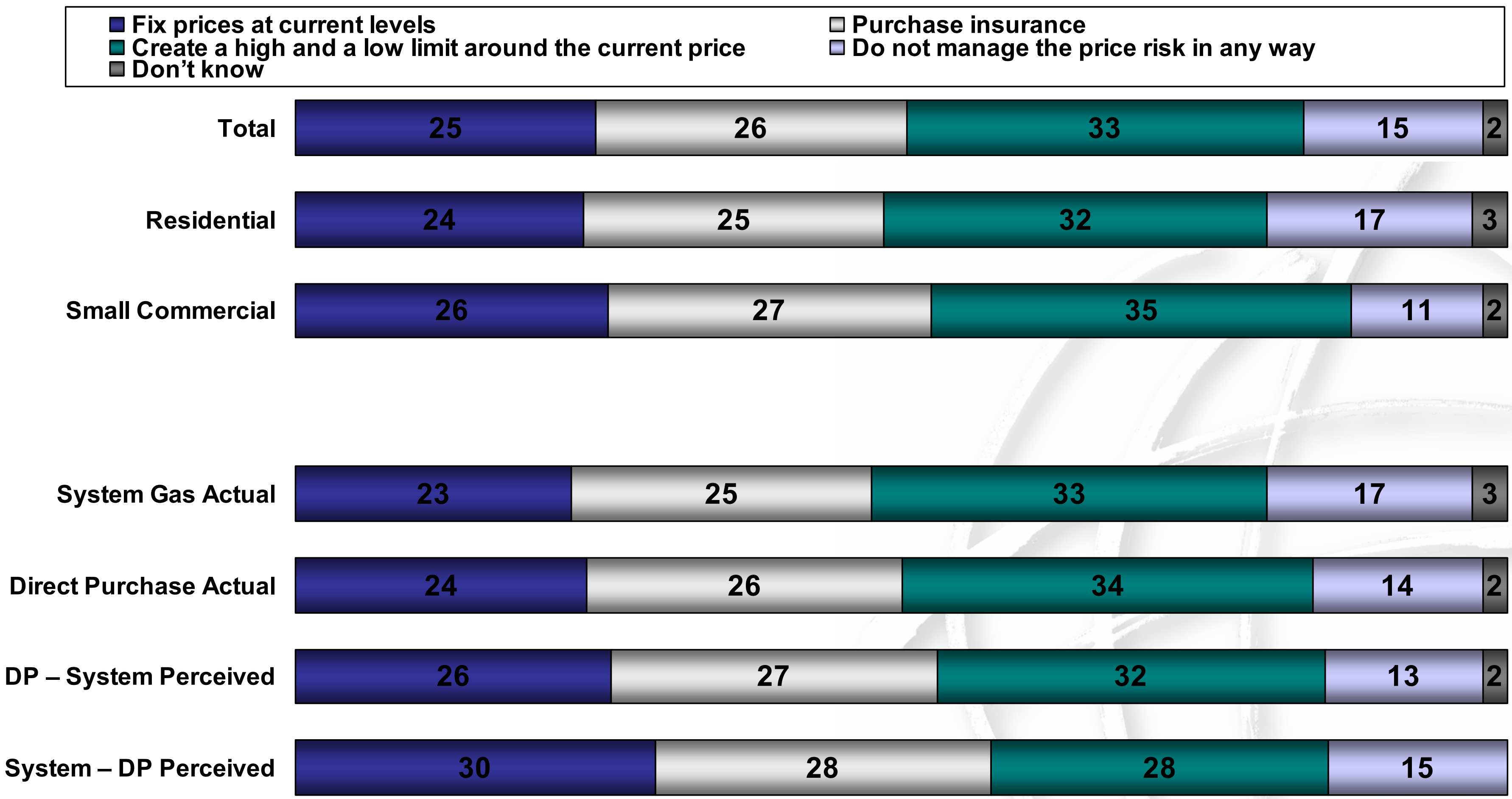
Q23. If Enbridge were to make a total adjustment for the year, in the amount of [INSERT ITEM] which would be a refund to be paid to you, do you think they should adjust your bill for this amount at the end of the year or should they make smaller adjustments throughout the year?
Q24. And, if Enbridge were to make a total adjustment for the year, in the amount of [INSERT ITEM] which would be a payment to be collected from you, should they adjust your bill for this amount at the end of the year or should they make smaller adjustments throughout the year?

Risk Management

Strategy Preferences

Risk Management Strategy Preference

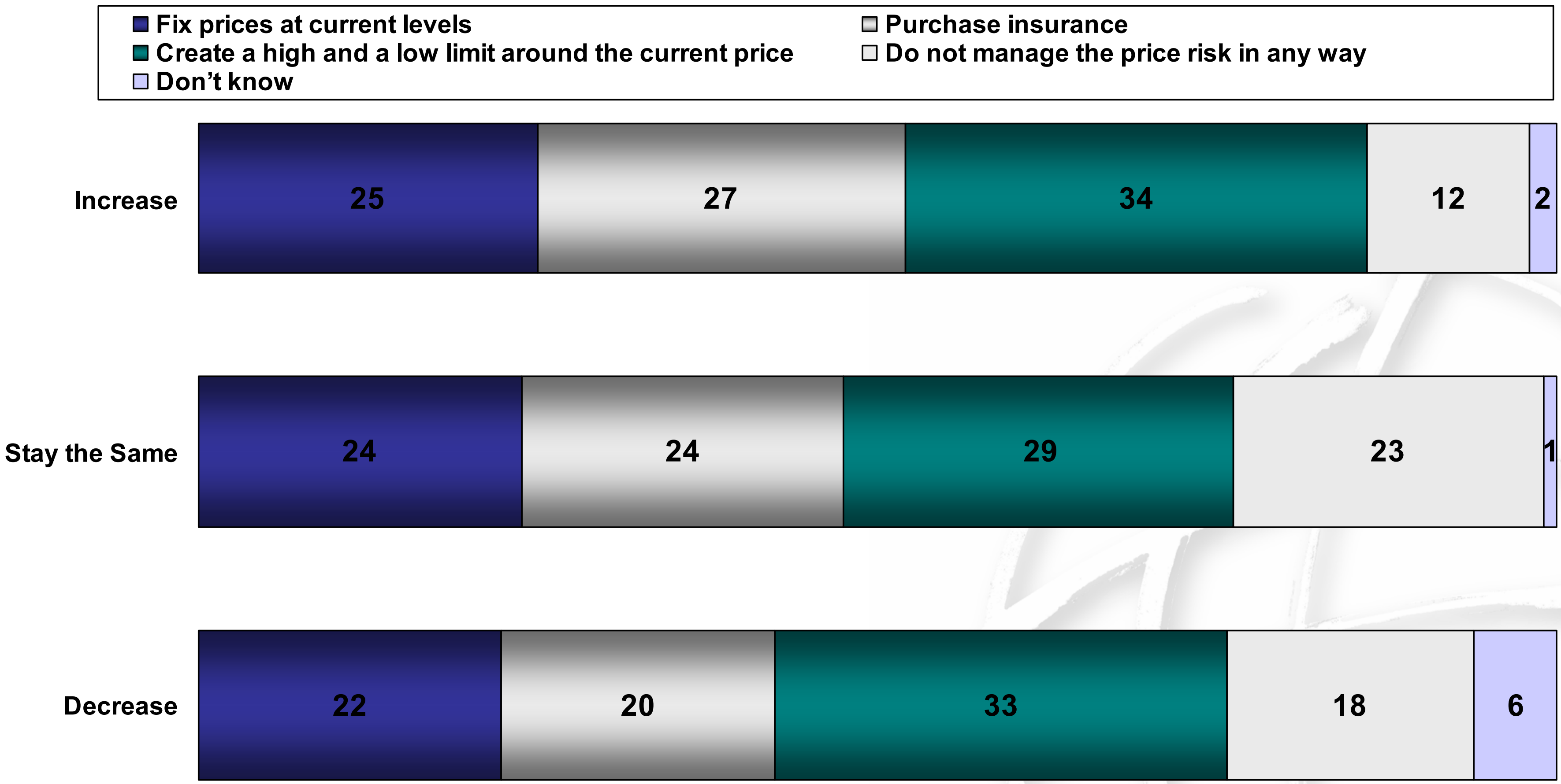
In general, creating a high and low limit around the current price is the preferred strategy of one-third of customers (33%). The next most preferred approaches, purchase insurance (26%) and fixing prices at current levels (25%) are evenly matched at about one-quarter each. Only about one-in-seven (15%) would not like Enbridge to manage the price risk in any way. These results are consistent for both residential and small commercial customers and across customer types.



Q14. Which of these four approaches would you like to see Enbridge use on behalf of its customers?

Risk Management Strategy Preference And Perceptions of the Future of Natural Gas Prices

Customers that expect the market price for natural gas to stay the same over the next year are more likely to prefer that Enbridge not manage the price risk than are those who expect the price to increase (23% versus 12%).



Q14. Which of these four approaches would you like to see Enbridge use on behalf of its customers?

Strategy Preference Change – Price Decrease

Nearly two-thirds of respondents (64%) who originally stated a preference for Enbridge to fix prices at current levels indicated that a price decrease of 50% would change their response. When provided with the options again, almost one-half (45%) of these chose a strategy that allowed them some benefit from falling prices. Seven percent of those who originally chose an approach that afforded some protection from increasing prices now opted for Enbridge to NOT manage the price risk in any way.

	Fix Prices at Current Levels	Purchase Insurance	Create a High and Low Limit	Do Not Manage the Price Risk
Would a Price Decrease of 50% Change your Preference?				
N=	294	308	396	174
Yes	64	57	50	43
No	33	40	48	53
Don't know	3	3	2	3
What Pricing Approach Would You Like Enbridge to Use if the Price Decreased by 50%?				
Base: Respondents who said a price decrease of 50% would change their response	188	176	196	75
Fix Prices at Current Levels	54	15	17	16
Purchase Insurance	13	51	14	16
Create a High and Low Limit	24	18	49	19
Do Not Manage the Price Risk	8	13	17	44
Don't know	2	3	3	5

Q14. Which of these four approaches would you like to see Enbridge use on behalf of its customers?
Q15. If this price decreased 50% to $300, would this change your answer with respect to how you would like to see Enbridge manage the cost of the natural gas commodity on behalf of its customers?
Q16. And, what pricing approach would you like to see Enbridge use on behalf of its customers if the current market price of gas commodity decreased by 50%?

Strategy Preference Change – Price Increase

Interestingly, less than one-third (32%) of customers who preferred that Enbridge not manage the price risk indicated that a price increase of 50% would change their response. Six-in-ten (60%) of these chose a new approach that afforded some protection from increasing prices. More than one-half of those who chose one of the risk management strategies reported that a price increase of 50% would not change their response. In addition, about half of those who stated that a price increase would change their response selected the same pricing approach when provided with the options.

	Fix Prices at Current Levels	Purchase Insurance	Create a High and Low Limit	Do Not Manage the Price Risk
Would a Price Increase of 50% Change your Preference?				
N=	294	308	396	174
Yes	45	42	39	32
No	53	58	59	64
Don't know	3	1	2	4
What Pricing Approach Would You Like Enbridge to Use if the Price Increased by 50%?				
Base: Respondents who said a price increase of 50% would change their response	131	128	154	55
Fix Prices at Current Levels	54	24	25	20
Purchase Insurance	18	46	20	26
Create a High and Low Limit	20	22	46	15
Do Not Manage the Price Risk	5	4	8	35
Don't know	3	4	2	6

Q17. Which of these four approaches would you like to see Enbridge use on behalf of its customers?
Q18. If the current market price of natural gas commodity for the next year increased 50% to approximately $900, would this change your answer with respect to how you would like to see Enbridge manage the cost of the natural gas commodity on behalf of its customers?
Q19. And, what pricing approach would you like to see Enbridge use on behalf of its customers if the current market price of the natural gas commodity increased by 50%?

Original
EB-2005-0001
Exhibit A3
Tab 3
Schedule 1
Attachment

Ipsos Reid

Enbridge Gas Distribution

Customer Threshold for Gas Supply Volatility Study

December 2004

ENBRIDGE

CR-374

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

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

VECC INTERROGATORY #73

INTERROGATORY

Reference: Ex. G2, Tab 2, Sch. 1, and Sch. 2, page 1

Request: a) Please provide the Revenue to Cost Rate of Return Comparison tables (Sch. 1 and Sch. 2) for the last 5 Rate Applications that were approved by the Board.

b) Please provide the Revenue to Cost ratios for distribution only (i.e., exclusive of gas supply commodity, gas supply load balancing, and transportation) by rate class for the last 5 years and the 2006 test year.

c) How is the return on rate base per rate class derived?

d) In rate making does Enbridge attempt to maintain consistent return of rate base for each rate class over the years?

e) Why is it reasonable that the Rates 115, 135, and 170, have a negative return on rate base?

RESPONSE

a) Revenue to Cost Exhibits (Schedules 1 and 2) as approved by the Board are provided herein as Attachment A for:
   - 2005
   - 2003
   - 2002
   - 2001

   Note: 2004 was not a cost-of-service year. Schedules not attached.

b) Distribution Only Revenue to Cost Exhibits (Schedules 1 and 2) are provided herein as Attachment B for:
   - 2006
   - 2005
   - 2003
   - 2002
   - 2001

Note: 2004 was not a cost-of-service year. Schedules not attached.

c) The return on rate base per rate class is derived by taking the return allocated to the rate class (Exhibit G2, Tab 5, Schedule 3, p. 1, Line 6.1, Col. 4) and the return component of the rate class over/under contribution (Exhibit G2, Tab 2, Schedule 1, p. 1, Line 5, Col. 2) divided by the rate base allocated to the rate class (Exhibit G2, Tab 2, Schedule 1, p. 1, Line 7, Col. 2).

The derivation for Rate 1 is provided below to help illustrate the return on rate base calculation.

($186.67 + $1.06 * $284.34 / $363.37) / $2239.35 = 0.0837 = <u>8.37%</u>

The derivation of the return on rate base per rate class, excluding gas supply commodity, follows the approach outlined above, but excludes commodity-related return.

d) In designing rates the Company follows established rate making principles including:

- cost causality (rates to be based on costs incurred to provide service to the
- rate classes);
- minimize cross-subsidization;
- promote market acceptance; and
- minimize rate shock.

The Company endeavors to maintain consistent revenue to cost ratios for each rate class on a year to year basis, while balancing the other objectives mentioned above.

e) The negative return on rate base for Rates 115, 135, and 170 for 2006 is a consequence of the phased implementation of the cost allocation changes and will disappear once these changes are fully implemented.

REVENUE TO COSTS/
RATE OF RETURN COMPARISONS
SEPT. 30, 2005

(millions of dollars)

ITEM NO.	DESCRIPTION	Col. 1 TOTAL	Col. 2 RATE 1	Col. 3 RATE 6	Col. 4 RATE 9	Col. 5 RATE 100	Col. 6 RATE 110	Col. 7 RATE 115	Col. 8 RATE 135	Col. 9 RATE 145	Col. 10 RATE 170	Col. 11 RATE 200	Col. 12 RATE 300	Col. 13 RATE 300 CDS	Col. 14 RATE 305	Col. 15 RATE 325 & 330	Col. 16 DIRECT PURCHASE
1.	Sales and Trans. Revenue	2,889.96	1,671.18	850.59	4.30	160.54	44.94	42.44	2.69	26.32	43.14	40.29	0.00	0.07	0.08	1.83	1.56
2.	Unbilled Revenues	1.65	1.08	0.46	0.00	0.12	(0.02)	(0.01)	0.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3.	Total Revenues	2,891.62	1,672.25	851.05	4.30	160.66	44.93	42.44	2.69	26.33	43.14	40.29	0.00	0.07	0.08	1.83	1.56
4.	Cost of Service	2,891.62	1,666.07	840.73	4.60	162.37	45.87	50.73	3.28	25.95	48.30	40.24	0.00	0.00	0.10	1.80	1.56
5.	Over/Under Contribution	0.00	6.19	10.32	(0.31)	(1.71)	(0.95)	(8.30)	(0.59)	0.38	(5.16)	0.05	0.00	0.07	(0.02)	0.03	(0.00)
6.	Over/Under Contribution ($ PER 10^3 m^3)		1.34	3.10	(23.84)	(1.22)	(1.52)	(8.95)	(10.08)	1.23	(6.29)	0.27	0.00	0.00	(1.50)	N/A	N/A
7.	Rate Base	3,422.10	2,121.73	769.47	8.79	200.53	36.30	22.33	1.85	22.48	15.61	9.73	0.00	0.00	0.35	190.93	
8.	Return on Rate Base	8.12%	8.35%	9.14%	5.37%	7.45%	6.19%	-21.04%	-16.96%	9.47%	-17.81%	8.52%	0.00%	0.00%	3.74%	9.63%	N/A
9.	Revenue to Cost Ratio	1.00	1.00	1.01	0.93	0.99	0.98	0.84	0.82	1.01	0.89	1.00	0.00	0.00	0.81	1.01	N/A

Final Board Order
Filed: 2004-11-22
RP-2003-0203
Exhibit G3
Tab 2
Schedule 2
Page 1 of 1

**REVENUE TO COST/
RATE OF RETURN COMPARISONS
EXCLUDING GAS SUPPLY COMMODITY
SEPT. 30, 2005**

(millions of dollars)

ITEM NO.	DESCRIPTION	Col. 1 TOTAL	Col. 2 RATE 1	Col. 3 RATE 6	Col. 4 RATE 9	Col. 5 RATE 100	Col. 6 RATE 110	Col. 7 RATE 115	Col. 8 RATE 135	Col. 9 RATE 145	Col. 10 RATE 170	Col. 11 RATE 200	Col. 12 RATE 300	Col. 13 RATE 300 CDS	Col. 14 RATE 305	Col. 15 RATE 325 & 330	Col. 16 DIRECT PURCHASE
1.	Sales and Trans. Revenue	1,568.28	872.75	415.17	1.71	131.59	40.23	42.44	2.21	20.02	27.64	10.99	0.00	0.07	0.08	1.83	1.56
2.	Unbilled Revenues	1.65	1.08	0.46	0.00	0.12	(0.02)	(0.01)	0.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3.	Total Revenues	1,569.93	873.83	415.64	1.71	131.71	40.21	42.44	2.21	20.03	27.64	10.99	0.00	0.07	0.08	1.83	1.56
4.	Cost of Service	1,569.93	867.65	405.32	2.02	133.41	41.16	50.73	2.80	19.65	32.80	10.94	0.00	0.00	0.10	1.80	1.56
5.	Over/Under Contribution	(0.00)	6.18	10.32	(0.31)	(1.71)	(0.95)	(8.30)	(0.59)	0.38	(5.17)	0.05	0.00	0.07	(0.02)	0.03	(0.00)
6.	Over/Under Contribution ($ PER 10^3 m^3)		1.34	3.10	(23.81)	(1.22)	(1.52)	(6.95)	(10.09)	1.23	(6.29)	0.27	0.00	0.00	0.00	N/A	
7.	Rate Base	3,406.12	2,113.28	784.88	8.76	200.22	38.25	22.33	1.85	22.41	15.44	9.41	0.00	0.00	0.35	190.93	0.00
8.	Indicated Return on Rate Base	8.12%	8.35%	9.15%	5.36%	7.45%	6.19%	-21.04%	-17.04%	9.47%	-18.09%	8.53%	0.00%	0.00%	3.74%	9.63%	N/A
9.	Revenue to Cost Ratio	1.00	1.01	1.03	0.85	0.99	0.98	0.84	0.79	1.02	0.84	1.00	0.00	0.00	0.81	1.01	N/A

Filed: 2003-04-02
Final Board Order
RP-2002-0133
Exhibit G2
Tab 2
Schedule 1
Page 1 of 1

Original
EB-2005-0001
Exhibit I
Tab 25
Schedule 73
Page 3 of 8
Attachment A

REVENUE TO COSTS/
RATE OF RETURN COMPARISONS
SEPT. 30, 2003

(millions of dollars)

ITEM NO.	DESCRIPTION	Col. 1 TOTAL	Col. 2 RATE 1	Col. 3 RATE 6	Col. 4 RATE 9	Col. 5 RATE 100	Col. 6 RATE 110	Col. 7 RATE 115	Col. 8 RATE 135	Col. 9 RATE 145	Col. 10 RATE 170	Col. 11 RATE 200	Col. 12 RATE 300	Col. 13 RATE 300 CDS	Col. 14 RATE 305	Col. 15 RATE 325 & 330	Col. 16 DIRECT PURCHASE
1.	Sales and Trans. Revenue	2,267.92	1,281.14	663.33	2.05	139.01	39.54	39.07	3.66	22.81	37.54	35.93	0.00	0.01	0.06	2.22	1.56
2.	Unbilled Revenues	0.01	0.09	(0.53)	0.00	0.22	0.23	(0.20)	(0.03)	0.57	(0.33)	0.00	0.00	0.00	0.00	0.00	0.00
3.	Total Revenues	2,267.94	1,281.23	662.80	2.05	139.23	39.77	38.87	3.63	23.37	37.21	35.93	0.00	0.01	0.06	2.22	1.56
4.	Cost of Service	2,267.94	1,290.66	660.65	2.13	137.64	38.16	37.57	2.76	22.10	36.92	35.59	0.00	0.00	0.06	2.12	1.58
5.	Over/Under Contribution	(0.00)	(9.43)	2.15	(0.08)	1.59	1.61	1.29	0.87	1.27	0.29	0.34	0.00	0.01	(0.00)	0.10	(0.02)
6.	Over/Under Contribution ($ PER 10^3 m^3)		(2.22)	0.69	(6.32)	1.14	2.45	1.38	8.97	4.23	0.35	1.81	0.00	0.00	(0.62)	N/A	N/A
7.	Rate Base	3,155.80	1,949.29	737.13	9.41	171.18	40.68	22.04	2.18	22.50	16.13	7.05	0.00	0.00	0.20	178.02	
8.	Return on Rate Base	8.32%	7.95%	8.54%	7.66%	9.02%	11.31%	12.74%	36.36%	12.58%	9.66%	12.00%	0.00%	0.00%	6.52%	9.63%	N/A
9.	Revenue to Cost Ratio	1.00	0.99	1.00	0.96	1.01	1.04	1.04	1.33	1.06	1.01	1.01	0.00	0.00	0.92	1.05	N/A

ENBRIDGE

Filed: 2003-04-02
Final Board Order
RP-2002-0133
Exhibit G2
Tab 2
Schedule 2
Page 1 of 1

**REVENUE TO COST/
RATE OF RETURN COMPARISONS
EXCLUDING GAS SUPPLY COMMODITY
SEPT. 30, 2003**

(millions of dollars)

ITEM NO.	DESCRIPTION	Col. 1 TOTAL	Col. 2 RATE 1	Col. 3 RATE 6	Col. 4 RATE 9	Col. 5 RATE 100	Col. 6 RATE 110	Col. 7 RATE 115	Col. 8 RATE 135	Col. 9 RATE 145	Col. 10 RATE 170	Col. 11 RATE 200	Col. 12 RATE 300	Col. 13 RATE 300 CDS	Col. 14 RATE 305	Col. 15 RATE 325 & 330	Col. 16 DIRECT PURCHASE
1.	Sales and Trans. Revenue	1,456.82	803.88	397.94	1.65	117.86	37.69	39.07	3.66	17.14	24.29	9.80	0.00	0.01	0.06	2.22	1.56
2.	Unbilled Revenues	0.01	0.09	(0.53)	0.00	0.22	0.23	(0.20)	(0.03)	0.57	(0.33)	0.00	0.00	0.00	0.00	0.00	0.00
3.	Total Revenues	1,456.84	803.97	397.41	1.65	118.08	37.92	38.87	3.63	17.70	23.96	9.80	0.00	0.01	0.06	2.22	1.56
4.	Cost of Service	1,456.84	813.40	395.26	1.73	116.49	36.31	37.57	2.76	16.43	23.67	9.46	0.00	0.00	0.06	2.12	1.58
5.	Over/Under Contribution	0.00	(9.43)	2.15	(0.08)	1.59	1.61	1.29	0.87	1.27	0.29	0.34	0.00	0.01	(0.00)	0.10	(0.02)
6.	Over/Under Contribution ($ PER 10^3 m^3)		(2.22)	0.69	(6.35)	1.14	2.45	1.38	8.99	4.24	0.35	1.81	0.00	0.00	0.00	N/A	
7.	Rate Base	3,136.29	1,937.80	730.76	9.40	170.67	40.63	22.04	2.18	22.36	15.81	6.42	0.00	0.00	0.20	178.02	0.00
8.	Indicated Return on Rate Base	8.32%	7.95%	8.54%	7.66%	9.02%	11.31%	12.74%	38.42%	12.61%	9.69%	12.36%	0.00%	0.00%	6.52%	9.63%	N/A
9.	Revenue to Cost Ratio	1.00	0.99	1.01	0.95	1.01	1.04	1.03	1.31	1.08	1.01	1.04	0.00	0.00	0.92	1.05	N/A

ENBRIDGE

**REVENUE TO COSTS/
RATE OF RETURN COMPARISONS
SEPT. 30, 2002**

(millions of dollars)

ITEM NO.	DESCRIPTION	Col. 1 TOTAL	Col. 2 RATE 1	Col. 3 RATE 6	Col. 4 RATE 9	Col. 5 RATE 100	Col. 6 RATE 110	Col. 7 RATE 115	Col. 8 RATE 135	Col. 9 RATE 145	Col. 10 RATE 170	Col. 11 RATE 200	Col. 12 RATE 300	Col. 13 RATE 300 CDS	Col. 14 RATE 305	Col. 15 RATE 325 & 330	Col. 16 DIRECT PURCHASE
1.	Sales and Trans. Revenue	2,242.54	1,225.55	677.37	2.25	151.39	43.23	40.37	4.03	28.23	35.69	32.98	0.08	0.02	0.05	2.20	1.12
2.	Unbilled Revenues	(3.29)	(1.63)	(0.72)	0.00	(0.44)	(0.13)	(0.17)	(0.01)	(0.08)	(0.12)	0.00	0.00	0.00	0.00	0.00	0.00
3.	Total Revenues	2,239.25	1,223.93	676.65	2.25	150.95	43.10	40.20	4.02	28.14	35.57	32.98	0.08	0.02	0.05	2.20	1.12
4.	Cost of Service	2,239.25	1,232.76	670.89	2.21	151.43	42.48	39.28	2.92	25.67	35.53	32.72	0.07	0.00	0.06	2.09	1.15
5.	Over/Under Contribution	0.00	(8.83)	5.76	0.04	(0.48)	0.62	0.92	1.10	0.47	0.04	0.26	0.01	0.02	(0.01)	0.11	(0.03)
6.	Over/Under Contribution ($ PER 10^3 m^3)		(2.10)	1.80	2.80	(0.34)	1.02	1.00	11.88	1.43	0.05	1.43	3.41	0.00	(1.57)	N/A	N/A
7.	Rate Base	3,019.30	1,825.17	675.44	10.10	172.94	49.08	42.36	2.26	27.28	28.91	8.75	0.24	0.00	0.21	176.56	
8.	Return on Rate Base	8.26%	7.90%	8.90%	8.59%	8.06%	9.21%	9.88%	44.47%	9.56%	8.36%	10.47%	11.37%	0.00%	3.82%	10.31%	N/A
9.	Revenue to Cost Ratio	1.00	0.99	1.01	1.02	1.00	1.01	1.03	1.38	1.02	1.00	1.01	1.15	0.00	0.80	1.05	N/A

ENBRIDGE
Consumers Gas

**REVENUE TO COST/
RATE OF RETURN COMPARISONS
EXCLUDING GAS SUPPLY COMMODITY
SEPT. 30, 2002**

(millions of dollars)

ITEM NO.	DESCRIPTION	Col. 1 TOTAL	Col. 2 RATE 1	Col. 3 RATE 6	Col. 4 RATE 9	Col. 5 RATE 100	Col. 6 RATE 110	Col. 7 RATE 115	Col. 8 RATE 135	Col. 9 RATE 145	Col. 10 RATE 170	Col. 11 RATE 200	Col. 12 RATE 300	Col. 13 RATE 300 CDS	Col. 14 RATE 305	Col. 15 RATE 325 & 330	Col. 16 DIRECT PURCHASE
1.	Sales and Trans. Revenue	1,386.66	752.23	383.19	1.71	114.88	35.68	39.94	3.49	18.65	23.90	9.54	0.08	0.02	0.05	2.20	1.12
2.	Unbilled Revenues	(3.29)	(1.63)	(0.72)	0.00	(0.44)	(0.13)	(0.17)	(0.01)	(0.08)	(0.12)	0.00	0.00	0.00	0.00	0.00	0.00
3.	Total Revenues	1,383.37	750.61	382.47	1.71	114.44	35.55	39.78	3.48	18.56	23.78	9.54	0.08	0.02	0.05	2.20	1.12
4.	Cost of Service	1,383.37	759.43	376.71	1.66	114.92	34.93	38.86	2.38	18.09	23.74	9.28	0.07	0.06	0.06	2.09	1.15
5.	Over/Under Contribution	0.00	(8.83)	5.76	0.04	(0.48)	0.62	0.92	1.10	0.48	0.04	0.26	0.01	(0.04)	(0.01)	0.11	(0.03)
6.	Over/Under Contribution ($ PER 10^3 m^3)		(2.10)	1.80	2.81	(0.34)	1.02	1.00	11.88	1.43	0.05	1.43	0.00	0.00	0.00	N/A	
7.	Rate Base	2,995.67	1,811.99	667.25	10.08	171.93	48.86	42.35	2.25	27.07	28.58	8.10	0.24	0.21	0.21	176.56	0.00
8.	Indicated Return on Rate Base	8.26%	7.90%	8.90%	8.59%	8.05%	9.21%	9.88%	44.71%	9.57%	8.36%	10.65%	11.37%	-7.39%	3.82%	10.31%	N/A
9.	Revenue to Cost Ratio	1.00	0.99	1.02	1.03	1.00	1.02	1.02	1.46	1.03	1.00	1.03	1.15	0.28	0.80	1.05	N/A

ENBRIDGE
Consumers Gas

**REVENUE TO COSTS/
RATE OF RETURN COMPARISONS
SEPT. 30, 2001**

(millions of dollars)

		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 10	Col. 11	Col. 12	Col. 13	Col. 14	Col. 15
ITEM NO.	DESCRIPTION	TOTAL	RATE 1	RATE 6	RATE 9	RATE 100	RATE 110	RATE 115	RATE 135	RATE 145	RATE 170	RATE 200	RATE 300	RATE 310	RATE 325 & 330	DIRECT PURCHASE
1.	Sales and Trans. Revenue	2,728.04	1,490.84	810.05	3.47	193.81	52.38	42.78	3.93	40.29	43.85	42.85	0.30	0.00	2.41	1.07
2.	Unbilled Revenues	12.09	7.12	3.80	0.00	0.48	0.23	0.08	0.03	0.12	0.23	0.00	0.00	0.00	0.00	0.00
3.	Total Revenues	2,740.13	1,497.96	813.84	3.47	194.29	52.62	42.86	3.96	40.41	44.08	42.85	0.30	0.00	2.41	1.07
4.	Cost of Service	2,740.13	1,503.72	807.11	2.98	195.25	52.43	42.98	3.40	40.94	45.01	42.86	0.10	0.00	2.26	1.09
5.	Over/Under Contribution	(0.00)	(5.76)	6.73	0.49	(0.95)	0.19	(0.12)	0.56	(0.53)	(0.93)	(0.02)	0.20	0.00	0.15	(0.02)
6.	Over/Under Contribution ($ PER 10^3 m^3)		(1.38)	2.14	26.47	(0.87)	0.31	(0.12)	7.80	(1.50)	(1.07)	(0.07)	56.16	0.00	N/A	N/A
7.	Rate Base	3,118.20	1,842.13	708.35	11.09	195.93	52.65	52.24	1.87	36.16	39.08	13.25	0.37	0.00	165.06	
8.	Return on Rate Base	8.54%	8.31%	9.24%	11.81%	8.19%	8.80%	8.37%	30.60%	7.47%	6.80%	8.46%	48.10%	0.00%	10.83%	N/A
9.	Revenue to Cost Ratio	1.00	1.00	1.01	1.17	1.00	1.00	1.00	1.16	0.99	0.98	1.00	2.98	0.00	1.07	N/A

ENBRIDGE
Consumers Gas

REVENUE TO COST/
RATE OF RETURN COMPARISONS
EXCLUDING GAS SUPPLY COMMODITY
SEPT. 30, 2001

(millions of dollars)

ITEM NO.	DESCRIPTION	Col. 1 TOTAL	Col. 2 RATE 1	Col. 3 RATE 6	Col. 4 RATE 9	Col. 5 RATE 100	Col. 6 RATE 110	Col. 7 RATE 115	Col. 8 RATE 135	Col. 9 RATE 145	Col. 10 RATE 170	Col. 11 RATE 200	Col. 12 RATE 300	Col. 13 RATE 310	Col. 14 RATE 325 & 330	Col. 15 DIRECT PURCHASE
1.	Sales and Trans. Revenue	1,383.80	740.03	378.70	2.06	119.14	35.09	42.78	2.84	21.39	27.45	10.72	0.30	0.00	2.41	1.07
2.	Unbilled Revenues	12.09	7.12	3.80	0.00	0.48	0.23	0.06	0.03	0.12	0.23	0.00	0.00	0.00	0.00	0.00
3.	Total Revenues	1,395.88	747.15	382.50	2.06	119.63	35.33	42.88	2.88	21.51	27.68	10.72	0.30	0.00	2.41	1.07
4.	Cost of Service	1,395.89	752.91	375.78	1.56	120.58	35.14	42.98	2.11	22.04	28.61	10.73	0.10	0.00	2.26	1.09
5.	Over/Under Contribution	(0.00)	(5.76)	6.73	0.49	(0.95)	0.19	(0.12)	0.56	(0.53)	(0.93)	(0.02)	0.20	0.00	0.15	(0.02)
6.	Over/Under Contribution ($ PER 10^3 m^3)		(1.38)	2.14	26.45	(0.67)	0.32	(0.12)	7.80	(1.50)	(1.07)	(0.07)	0.00	0.00	N/A	
7.	Rate Base	3,078.36	1,819.87	696.58	11.05	193.72	52.14	52.24	1.83	36.60	38.60	12.30	0.37	0.00	165.06	0.00
8.	Indicated Return on Rate Base	8.54%	8.31%	9.25%	11.82%	8.18%	8.80%	8.37%	31.05%	7.45%	6.78%	8.45%	48.10%	0.00%	10.83%	N/A
9.	Revenue to Cost Ratio	1.00	0.99	1.02	1.32	0.99	1.01	1.00	1.27	0.98	0.97	1.00	2.98	0.00	1.07	N/A

ENBRIDGE
Consumers Gas

REVENUE TO COSTS/
RATE OF RETURN COMPARISONS
SEPT. 30, 2006

(millions of dollars)

		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 10	Col. 11	Col. 12	Col. 13	Col. 14	Col. 15	Col. 16
ITEM NO.	DESCRIPTION	TOTAL	RATE 1	RATE 6	RATE 9	RATE 100	RATE 110	RATE 115	RATE 135	RATE 145	RATE 170	RATE 200	RATE 300	RATE 300 CDS	RATE 305	RATE 325 & 330	DIRECT PURCHASE
1.	Distribution Revenue	992.63	661.41	234.28	0.93	58.71	11.96	9.01	0.76	4.56	3.41	2.30	0.00	0.01	0.17	1.86	3.27
2.	Unbilled Revenues	(1.55)	(1.06)	(0.49)	0.00	(0.00)	(0.00)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3.	Total Revenues	991.08	660.35	233.79	0.93	58.71	11.95	9.01	0.76	4.56	3.41	2.30	0.00	0.01	0.17	1.86	3.27
4.	Cost of Service	991.08	652.30	235.40	1.40	63.40	11.91	8.17	0.49	4.78	4.99	2.92	0.00	0.00	0.19	1.83	3.27
5.	Over/Under Contribution	(0.00)	8.05	(1.61)	(0.47)	(4.70)	0.05	0.84	0.28	(0.22)	(1.58)	(0.62)	0.00	0.01	(0.02)	0.03	0.00
6.	Over/Under Contribution ($ PER 10^3 m^3)		1.75	(0.50)	(49.95)	(3.32)	0.07	0.81	5.02	(0.88)	(2.05)	(4.02)	0.00	0.00	(0.79)	N/A	N/A
7.	Rate Base	3,603.87	2,239.35	829.06	8.85	215.68	41.68	26.13	1.60	18.52	19.38	10.09	0.00	0.00	0.67	192.87	N/A
8.	Return on Rate Base	6.89%	7.17%	6.73%	2.75%	5.18%	6.97%	9.39%	20.41%	5.95%	0.52%	2.05%	0.00%	0.00%	4.11%	8.59%	N/A
9.	Revenue to Cost Ratio	1.00	1.01	0.99	0.67	0.93	1.00	1.10	1.57	0.95	0.68	0.79	0.00	0.00	0.87	1.02	1.00

REVENUE TO COSTS/
RATE OF RETURN COMPARISONS
SEPT. 30, 2005

(millions of dollars)

ITEM NO.	DESCRIPTION	Col. 1 TOTAL	Col. 2 RATE 1	Col. 3 RATE 6	Col. 4 RATE 9	Col. 5 RATE 100	Col. 6 RATE 110	Col. 7 RATE 115	Col. 8 RATE 135	Col. 9 RATE 145	Col. 10 RATE 170	Col. 11 RATE 200	Col. 12 RATE 300	Col. 13 RATE 300 CDS	Col. 14 RATE 305	Col. 15 RATE 325 & 330	Col. 16 DIRECT PURCHASE
1.	Distribution Revenue	908.45	601.23	216.09	1.16	54.23	11.27	8.40	0.80	5.52	4.00	2.20	0.00	0.07	0.08	1.83	1.56
2.	Unbilled Revenues	1.65	1.08	0.46	0.00	0.12	(0.02)	(0.01)	0.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3.	Total Revenues	910.10	602.31	216.55	1.16	54.35	11.25	8.40	0.80	5.54	4.00	2.20	0.00	0.07	0.08	1.83	1.56
4.	Cost of Service	910.10	593.99	221.27	1.27	58.85	10.87	7.08	0.56	5.78	4.27	2.71	0.00	0.00	0.09	1.80	1.56
5.	Over/Under Contribution	0.00	8.32	(4.71)	(0.11)	(4.50)	0.38	1.31	0.24	(0.25)	(0.27)	(0.51)	0.00	0.07	(0.01)	0.03	(0.00)
6.	Over/Under Contribution ($ PER 10^3 m^3)		1.80	(1.42)	(8.28)	(3.21)	0.61	1.41	4.11	(0.80)	(0.33)	(2.96)	0.00	0.00	(1.01)	N/A	N/A
7.	Rate Base	3,422.10	2,121.73	789.47	8.79	200.53	38.30	22.33	1.85	22.48	15.61	9.73	0.00	0.00	0.35	190.93	
8.	Return on Rate Base	6.69%	7.00%	6.22%	5.73%	4.92%	7.49%	11.38%	16.98%	5.84%	5.41%	2.60%	0.00%	0.00%	3.74%	9.63%	N/A
9.	Revenue to Cost Ratio	1.00	1.01	0.98	0.92	0.92	1.04	1.19	1.43	0.96	0.94	0.81	0.00	0.00	0.86	1.01	N/A

REVENUE TO COSTS/
RATE OF RETURN COMPARISONS
SEPT. 30, 2003

(millions of dollars)

ITEM NO.	DESCRIPTION	Col. 1 TOTAL	Col. 2 RATE 1	Col. 3 RATE 6	Col. 4 RATE 9	Col. 5 RATE 100	Col. 6 RATE 110	Col. 7 RATE 115	Col. 8 RATE 135	Col. 9 RATE 145	Col. 10 RATE 170	Col. 11 RATE 200	Col. 12 RATE 300	Col. 13 RATE 300 CDS	Col. 14 RATE 305	Col. 15 RATE 325 & 330	Col. 16 DIRECT PURCHASE
1.	Distribution Revenue	870.55	559.40	209.54	1.28	51.54	15.05	12.09	1.74	7.12	6.24	2.71	0.00	0.01	0.06	2.22	1.58
2.	Unbilled Revenues	0.01	0.09	(0.53)	0.00	0.22	0.23	(0.20)	(0.03)	0.57	(0.33)	0.00	0.00	0.00	0.00	0.00	0.00
3.	Total Revenues	870.57	559.49	209.01	1.28	51.76	15.28	11.89	1.71	7.68	5.91	2.71	0.00	0.01	0.06	2.22	1.58
4.	Cost of Service	870.57	559.39	212.10	1.22	53.05	13.84	10.31	0.81	7.00	6.36	2.76	0.00	0.00	0.06	2.12	1.58
5.	Over/Under Contribution	(0.00)	0.10	(3.10)	0.06	(1.28)	1.44	1.58	0.90	0.69	(0.46)	(0.05)	0.00	0.01	(0.00)	0.10	(0.02)
6.	Over/Under Contribution ($ PER 10^3 m^3)		0.02	(0.89)	5.03	(0.92)	2.19	1.68	9.31	2.29	(0.56)	(0.25)	0.00	0.00	(0.19)	N/A	N/A
7.	Rate Base	3,155.80	1,949.29	737.13	9.41	171.18	40.68	22.04	2.18	22.50	16.13	7.05	0.00	0.00	0.20	178.02	
8.	Return on Rate Base	7.07%	7.07%	6.75%	7.59%	6.50%	9.74%	12.47%	38.24%	9.37%	4.92%	6.57%	0.00%	0.00%	6.52%	9.63%	N/A
9.	Revenue to Cost Ratio	1.00	1.00	0.99	1.05	0.98	1.10	1.17	2.16	1.10	0.93	0.98	0.00	0.00	0.98	1.05	N/A

REVENUE TO COSTS/
RATE OF RETURN COMPARISONS
SEPT. 30, 2002

(millions of dollars)

ITEM NO.	DESCRIPTION	Col. 1 TOTAL	Col. 2 RATE 1	Col. 3 RATE 6	Col. 4 RATE 9	Col. 5 RATE 100	Col. 6 RATE 110	Col. 7 RATE 115	Col. 8 RATE 135	Col. 9 RATE 145	Col. 10 RATE 170	Col. 11 RATE 200	Col. 12 RATE 300	Col. 13 RATE 300 CDS	Col. 14 RATE 305	Col. 15 RATE 325 & 330	Col. 16 DIRECT PURCHASE
1.	Distribution Revenue	830.86	528.52	204.31	1.24	49.30	13.90	11.96	1.69	7.81	6.03	2.64	0.08	0.02	0.05	2.20	1.12
2.	Unbilled Revenues	(3.29)	(1.63)	(0.72)	0.00	(0.44)	(0.13)	(0.17)	(0.01)	(0.08)	(0.12)	0.00	0.00	0.00	0.00	0.00	0.00
3.	Total Revenues	827.57	526.90	203.59	1.24	48.87	13.78	11.79	1.68	7.72	5.91	2.64	0.08	0.02	0.05	2.20	1.12
4.	Cost of Service	827.57	524.06	201.41	1.07	51.96	14.06	12.33	0.68	7.98	7.77	2.91	0.06	0.00	0.06	2.09	1.15
5.	Over/Under Contribution	0.00	2.83	2.18	0.18	(3.09)	(0.28)	(0.54)	0.99	(0.26)	(1.86)	(0.27)	0.01	0.02	(0.01)	0.11	(0.03)
6.	Over/Under Contribution ($ PER 10^3 m^3)		0.67	0.68	11.14	(2.22)	(0.46)	(0.56)	10.76	(0.78)	(2.30)	(1.47)	4.82	0.00	(1.12)	N/A	N/A
7.	Rate Base	3,019.30	1,825.17	675.44	10.10	172.94	49.08	42.36	2.26	27.28	28.91	8.75	0.24	0.00	0.21	176.56	
8.	Return on Rate Base	6.98%	7.09%	7.22%	8.29%	5.64%	6.55%	6.03%	39.75%	6.27%	2.19%	4.69%	11.37%	0.00%	3.82%	10.31%	N/A
9.	Revenue to Cost Ratio	1.00	1.01	1.01	1.17	0.94	0.98	0.97	2.47	0.97	0.78	0.91	1.22	0.00	0.85	1.05	N/A

**REVENUE TO COSTS/
RATE OF RETURN COMPARISONS
SEPT. 30, 2001**

(millions of dollars)

ITEM NO.	DESCRIPTION	Col. 1 TOTAL	Col. 2 RATE 1	Col. 3 RATE 6	Col. 4 RATE 9	Col. 5 RATE 100	Col. 6 RATE 110	Col. 7 RATE 115	Col. 8 RATE 135	Col. 9 RATE 145	Col. 10 RATE 170	Col. 11 RATE 200	Col. 12 RATE 300	Col. 13 RATE 310	Col. 14 RATE 325 & 330	Col. 15 DIRECT PURCHASE
1.	Distribution Revenue	804.74	508.54	196.63	1.50	49.60	13.42	12.69	1.18	8.24	6.31	2.86	0.30	0.00	2.41	1.07
2.	Unbilled Revenues	12.09	7.12	3.80	0.00	0.48	0.23	0.08	0.03	0.12	0.23	0.00	0.00	0.00	0.00	0.00
3.	Total Revenues	816.83	515.66	200.42	1.50	50.08	13.66	12.77	1.21	8.36	6.54	2.86	0.30	0.00	2.41	1.07
4.	Cost of Service	816.83	504.74	198.40	0.79	54.85	14.73	15.23	0.72	9.92	10.22	3.78	0.09	0.00	2.26	1.09
5.	Over/Under Contribution	0.00	10.92	2.02	0.70	(4.78)	(1.08)	(2.46)	0.49	(1.56)	(3.68)	(0.92)	0.21	0.00	0.15	(0.02)
6.	Over/Under Contribution ($ PER 10^3 m^3)		2.62	0.64	37.78	(3.35)	(1.83)	(2.51)	6.84	(4.40)	(4.26)	(4.42)	58.81	0.00	N/A	N/A
7.	Rate Base	3,118.20	1,842.13	708.35	11.09	195.93	52.65	52.24	1.87	36.16	39.08	13.25	0.37	0.00	165.06	
8.	Return on Rate Base	6.68%	7.11%	6.89%	11.33%	4.89%	5.18%	3.22%	26.02%	3.52%	-0.24%	1.57%	48.10%	0.00%	10.83%	N/A
9.	Revenue to Cost Ratio	1.00	1.02	1.01	1.89	0.91	0.93	0.83	1.64	0.84	0.64	0.76	3.28	0.00	1.07	N/A

K 4.1

Ontario Energy Board
FILE No. EB-2006-0034
EXHIBIT No. K4.1
DATE February 1, 2007
08/99

Enbridge Gas Distribution Inc.

2007 Test Year
Approximate elements of
Changes in volumes & storage
Deficiency Amounts

Line No.		Col. 1 Filed: 2006-08-15 A2.T5.S1 Column 2 ($millions)	Col. 2 Filed: 2007-01-24 A2.T5.S2 Column 2 ($millions)
1.	Gross deficiency amount	22.2	16.1
	Approximate elements		
2.	Degree Days deficiency 20 year trend	12.9	12.9
3.	Average use deficiency	7.3	7.3
4.	Contract volumes deficiency	1.5	1.5
5.	Storage and transportation change deficiency	8.7	2.6
6.	Customer add volume growth sufficiency & other	(8.2)	(8.2)
7.	Changes in volumes and storage deficiency	22.2	16.1

Note:

The potential $ 5 million revenue sufficiency quoted on page 11 of the Settlement Proposal was achieved as follows.

a) In Exhibit N1, Tab 2, Schedule 2, page 2 of 2 of the Settlement Proposal, a remaining deficiency related to unresolved issues of $ 52.1 million is shown.

b) If each of lines 2, 3 & 4 on that page 2 are denied by the Board, the deficiency would decline to the $ 16.1 million relating to changes in volumes as shown on line 5 of that page 2 and as broken out above in column 2.

c) If the Board was to affirm the DeBever degree day method, the remaining volume related deficiency of $ 16.1 million would decrease by the $ 21.2 million shown with Board Staff Interrogatory #17, resulting in a sufficiency of approximately $ 5 million.

Some of the other volume related impacts shown on lines 3 to 6 could change from the approximate impacts shown above but would only change marginally in total.

K4.2

Table 1

Comparison of Nine Different Degree Days Forecast Methodologies

Item		Col. 1 Energy Probe	Col. 2 de Bever	Col. 3 de Bever with Trend	Col. 4 10-Yr MA	Col. 5 20-Yr MA	Col. 6 30-Yr MA	Col. 7 Avg(20-Yr, 30-Yr MA)	Col. 8 Naïve	Col. 9 20-Yr Trend
1.1	Total operating costs incurred by EGDI in utilizing the method ('$000)	There are no material or significant operating costs incurred by using each of the degree day forecasting methods.								
1.2	Total Bill Impact on a Typical Residential Customer vs 20-Yr Trend (%)	1.5%	3.2%	0.2%	1.4%	3.3%	5.3%	2.6%	1.9%	0.0%
1.3	Delivery Bill Impact on a Typical Residential Customer vs 20-Yr Trend (%)	0.3%	0.6%	0.0%	0.3%	0.6%	0.9%	0.5%	0.3%	0.0%
1.4	Impact on Revenue Requirement vs 20-Yr Trend (%)	0.4%	0.7%	0.0%	0.3%	0.7%	1.1%	0.5%	0.4%	0.0%
1.5	Impact on Revenue Deficiency vs 20-Yr Trend ($M)	12.3	21.2	1.6	9.7	22.1	35.0	17.6	12.6	0.0
1.6	Volumetric Impact vs 20-Yr Trend (10^6m^3)	192.1	331.7	25.0	151.8	345.6	548.2	275.0	196.5	0.0
1.7	Impact on Revenue Deficiency vs 2006 Board Approved Degree Days ($M)	-0.6	8.3	-11.3	-3.2	9.2	22.1	4.7	-0.3	-12.9

K4.3

Exhibit N3.2
Vol. 3, para. 240

UNION GAS LIMITED

Undertaking of Mr. Fogwill
To Mr. Aiken

Please provide the actual equation filed with the coefficients, the various regression statistics, along with all the regression statistics: T Stats, F Value, Durban-Watson, R Squared.

The linear regression equations are attached for the trend methods only. There is no regression equation possible for the 30, 20 and 10 year averages because they are simple averages.

The performance statistics used for assessing the methods compared each methods' performance against actual over time and did not use the statistics for each individual equation. The performance tests that Union has used were the mean absolute percent error, mean percent error, root mean squared error and standard deviation.

Witness: Allan Fogwill
Question: October 8, 2003
Answer: October 15, 2003
Docket: RP-2003-0063

Source: ExC2/T4/S1/p9

Table 5

Actual and Forecast Toronto Degree Days

Year	Actual	DeBever	Difference	% Difference	20-Yr Trend	Difference	% Difference	Union	Difference	% Difference
1990	3,980	4,032	52	1%	4,003	23	1%	4,092	112	3%
1991	3,610	4,035	425	12%	3,973	363	10%	4,075	465	13%
1992	4,053	4,035	-18	0%	3,962	-91	-2%	4,069	16	0%
1993	4,168	3,947	-221	-5%	3,865	-303	-7%	4,014	-154	-4%
1994	4,331	3,998	-333	-8%	3,870	-461	-11%	4,018	-313	-7%
1995	3,785	4,046	261	7%	3,883	98	3%	4,023	238	6%
1996	4,266	4,132	-134	-3%	3,942	-324	-8%	4,057	-209	-5%
1997	4,063	4,082	19	0%	3,863	-200	-5%	4,008	-55	-1%
1998	3,389	4,142	753	22%	3,896	507	15%	4,025	636	19%
1999	3,475	4,129	654	19%	3,929	454	13%	4,038	563	16%
2000	3,616	3,977	361	10%	3,833	217	6%	3,974	358	10%
2001	3,782	3,859	77	2%	3,748	-34	-1%	3,920	138	4%
2002	3,337	3,759	422	13%	3,683	346	10%	3,874	537	16%
2003	4,102	3,737	-365	-9%	3,684	-418	-10%	3,865	-237	-6%
2004	3,785	3,570	-215	-6%	3,614	-171	-5%	3,815	30	1%
2005	3,772	3,806	34	1%	3,647	-125	-3%	3,831	59	2%
2006	N/A									
Average Error 1990-2005	**3,845**	**3,955**	**111**	**3%**	**3,837**	**-7**	**-0.2%**	**3,981**	**137**	**4%**
No. of Times Overforecasted			10			7			11	

Ontario Energy Board

FILE No. EB-2006-0034

EXHIBIT No. K4.4

DATE February 1, 2007

08/99

Ontario Energy Board
FILE No. EB-2006-0034
EXHIBIT No. K4.5
DATE February 1, 2007
08/99

EB-2006-0034
Exhibit K 4.5

Degree Day Methodologies - Comparison of Performance 1990 - 2005

Toronto Region

Item	*Actual*	*Naïve*	*10 YR MA*	*20 YR MA*	*30 YR MA*	*50/50*	*de Bever*	*de Bever/Tr*	*Energy Probe*	*20 YR Trend*
Total Degree Days	61,513	62,016	63,524	65,069	66,001	63,698	63,285	62,096	62,580	61,395
Overforecast		8	11	12	12	11	10	6	6	7
Underforecast		8	5	4	4	5	6	10	10	9
Variance from Actual		503	2,011	3,556	4,488	2,185	1,772	583	1,067	-118
Percentage Variance		0.82%	3.27%	5.78%	7.30%	3.55%	2.88%	0.95%	1.73%	-0.19%

Eastern Region

Item	*Actual*	*Naïve*	*10 YR MA*	*20 YR MA*	*30 YR MA*	*50/50*	*de Bever*	*de Bever/Tr*	*Energy Probe*	*20 YR Trend*
Total Degree Days	72,093	72,234	72,873	73,631	74,387	73,062	73,145	72,214	72,601	71,738
Overforecast		7	7	9	10	7	6	7	7	6
Underforecast		9	9	7	6	9	10	9	9	10
Variance from Actual		141	780	1,538	2,294	969	1,052	121	508	-355
Percentage Variance		0.20%	1.08%	2.13%	3.18%	1.34%	1.46%	0.17%	0.70%	-0.49%

Niagara Region

Item	*Actual*	*Naïve*	*10 YR MA*	*20 YR MA*	*30 YR MA*	*50/50*	*de Bever*	*de Bever/Tr*	*Energy Probe*	*20 YR Trend*
Total Degree Days	57,102	57,191	57,888	58,644	58,911	57,884	58,547	58,038	58,987	56,856
Overforecast		8	8	10	12	8	10	10	11	7
Underforecast		8	8	6	4	8	6	6	5	9
Variance from Actual		89	786	1,542	1,809	782	1,445	936	1,885	-246
Percentage Variance		0.16%	1.38%	2.70%	3.17%	1.37%	2.53%	1.64%	3.30%	-0.43%

Averages

Item	*Actual*	*Naïve*	*10 YR MA*	*20 YR MA*	*30 YR MA*	*50/50*	*de Bever*	*de Bever/Tr*	*Energy Probe*	*20 YR Trend*
Average Degree Days	63,569	63,814	64,762	65,781	66,433	64,881	64,992	64,116	64,723	63,330
Avg. Overforecast		48%	54%	65%	71%	54%	54%	48%	50%	42%
Avg. Underforecast		52%	46%	35%	29%	46%	46%	52%	50%	58%
Average Variance		244	1,192	2,212	2,864	1,312	1,423	547	1,153	-240
Percentage Variance		0.38%	1.88%	3.48%	4.50%	2.06%	2.24%	0.86%	1.81%	-0.38%

Source: Toronto - I/16/20
Eastern and Niagara - I/5/8

Exhibit ________

<u>EB-2006-0034</u>

<u>Cross-Examination Materials</u>

<u>On</u>

<u>Average Use & Degree Days</u>

Energy Probe Research Foundation

January, 2007

Appendix 1

Mnemonics of the variables in the model are defined as follows:

Mnemonic	Definition
C	Constant Term
LOG(X)	Logarithm of Variable X
DLOG(X)	$LOG(X_t) - LOG(X_{t-1})$
CDD, EDD, NDD	Balance Point Heating Degree Days for Central, Eastern and Niagara Weather Zones
CRCE	Central Weather Zone Employment
ERCE	Eastern Weather Zone Employment
REAL_CRC_CPG	Real Commercial Gas Price for the Central Weather Zone
REAL_ERC_CPG	Real Commercial Gas Price for the Eastern Weather Zone
REAL_NRC_CPG	Real Natural Gas Price for the Niagara Weather Zone
OGDPFC	Ontario Real Gross Domestic Product
GOODS	Ontario Goods Producing Industry Real Domestic Product
TMAN	Ontario Manufacturing Industry Real Domestic Product
ORET92	Ontario Real Retail Sales
TIME	Time Trend
DUMPRE1991	Dummy Variable for Structural Break Prior to 1991
DUM00	Dummy Variable for 2000
DUM97	Dummy Variable for 1997
ECM_Region	Error Correction Term for Each Region

Appendix 2

Regression results are as follows:

Central Revenue Class 12 (Apartment)

Long Run Equation

Variable	Coefficient	t-Statistic
C	0.894	1.884
LOG(CDD)	0.638	24.350
LOG(TIME)	-0.028	-5.084
LOG(CRCE)	0.296	6.082
LOG(REAL_CRC_CPG)	-0.029	-2.070
AR(1)	-0.537	-2.415
F Statistic	96.595	
Adjusted R-squared	0.962	
S.E. of regression	0.010	

Eastern Revenue Class 12 (Apartment)

Long Run Equation

Variable	Coefficient	t-Statistic
C	3.932	8.947
LOG(EDD)	0.470	8.776
LOG(TIME)	-0.022	-4.903
LOG(REAL_ERC_CPG)	-0.037	-2.412
F Statistic	41.839	
Adjusted R-squared	0.860	
S.E. of regression	0.016	

Short Run Equation

Variable	Coefficient	t-Statistic
C	-0.004	-0.969
DLOG(EDD)	0.468	11.951
ECM_ERC12(-1)	-1.217	-4.454
F Statistic	83.652	
Adjusted R-squared	0.897	
S.E. of regression	0.017	

Witness: J. Denomy

Niagara Revenue Class 12 (Apartment)

Long Run Equation

Variable	Coefficient	t-Statistic
C	3.481	9.434
LOG(NDD)	0.496	10.725
LOG(TIME)	-0.009	-1.966
F Statistic	62.461	
Adjusted R-squared	0.860	
S.E. of regression	0.017	

Short Run Equation

Variable	Coefficient	t-Statistic
C	-0.002	-0.420
DLOG(NDD)	0.468	14.467
ECM_NRC12(-1)	-0.883	-3.643
F Statistic	132.238	
Adjusted R-squared	0.932	
S.E. of regression	0.017	

Central Revenue Class 48 (Commercial)

Long Run Equation

Variable	Coefficient	t-Statistic
C	-3.015	-2.939
LOG(CDD)	0.734	11.744
LOG(TIME)	-0.107	-5.814
LOG(OGDPFC)	0.316	5.279
DUMPRE1991	-0.074	-3.648
F Statistic	120.410	
Adjusted R-squared	0.960	
S.E. of regression	0.021	

Short Run Equation

Variable	Coefficient	t-Statistic
C	-0.017	-2.443
DLOG(CDD)	0.822	34.461
DLOG(OGDPFC)	0.834	5.460
ECM_CRC48(-1)	-0.637	-3.283
DLOG(TIME)	-0.124	-3.946
AR(3)	-0.457	-2.023
F Statistic	238.613	
Adjusted R-squared	0.987	
S.E. of regression	0.011	

Eastern Revenue Class 48 (Commercial)

Long Run Equation

Variable	Coefficient	t-Statistic
C	-0.752	-0.922
LOG(EDD)	0.734	11.492
LOG(TIME)	-0.147	-18.176
LOG(GOODS)	0.147	3.351
F Statistic	272.540	
Adjusted R-squared	0.976	
S.E. of regression	0.019	

Short Run Equation

Variable	Coefficient	t-Statistic
C	-0.006	-1.357
DLOG(EDD)	0.745	22.908
DLOG(TIME)	-0.096	-3.399
DLOG(GOODS)	0.174	2.041
ECM_ERC48(-1)	-1.390	-4.700
AR(2)	-0.419	-1.652
F Statistic	104.883	
Adjusted R-squared	0.968	
S.E. of regression	0.014	

Niagara Revenue Class 48 (Commercial)

Long Run Equation

Variable	Coefficient	t-Statistic
C	-2.007	-1.507
LOG(NDD)	0.680	10.873
LOG(TIME)	-0.051	-4.390
LOG(ORET92)	0.298	3.006
LOG(REAL_NRC_CPG)	-0.123	-3.371
F Statistic	37.990	
Adjusted R-squared	0.881	
S.E. of regression	0.021	

Short Run Equation

Variable	Coefficient	t-Statistic
C	-0.006	-1.507
DLOG(NDD)	0.639	17.253
DLOG(ORET92)	0.226	2.145
DLOG(REAL_NRC_CPG)	-0.034	-1.199
ECM_NRC48(-1)	-1.296	-5.254
F Statistic	139.704	
Adjusted R-squared	0.967	
S.E. of regression	0.016	

Central Revenue Class 73 (Industrial)

Long Run Equation

Variable	Coefficient	t-Statistic
C	-0.506	-0.333
LOG(CDD)	0.570	6.012
LOG(TIME)	-0.094	-3.457
LOG(OGDPFC)	0.305	3.419
DUM00	0.077	2.338
DUMPRE1991	-0.072	-2.397
F Statistic	29.461	
Adjusted R-squared	0.877	
S.E. of regression	0.030	

Short Run Equation

Variable	Coefficient	t-Statistic
C	-0.027	-3.309
DLOG(CDD)	0.662	14.384
DLOG(TIME)	-0.035	-1.115
DLOG(OGDPFC)	0.733	3.247
DUM00	0.070	3.042
ECM_CRC73(-1)	-0.965	-4.691
F Statistic	67.556	
Adjusted R-squared	0.946	
S.E. of regression	0.020	

Eastern Revenue Class 73 (Industrial)

Long Run Equation

Variable	Coefficient	t-Statistic
C	-3.700	-1.340
LOG(EDD)	1.003	4.436
LOG(TIME)	-0.165	-2.808
LOG(ERCE)	0.673	1.963
DUMPRE1991	-0.227	-3.357
DUM00	0.268	3.734

F Statistic	36.588	
Adjusted R-squared	0.899	
S.E. of regression	0.067	

Short Run Equation

Variable	Coefficient	t-Statistic
C	-0.035	-1.964
DLOG(EDD)	1.073	6.106
DUM00	0.318	3.947
ECM_ERC73(-1)	-0.940	-3.085

F Statistic	22.076	
Adjusted R-squared	0.769	
S.E. of regression	0.078	

Filed: 2006-08-15
EB-2006-0034
Exhibit C2
Tab 3
Schedule 2
Page 18 of 36

Niagara Revenue Class 73 (Industrial)

Long Run Equation

Variable	Coefficient	t-Statistic
C	-8.461	-3.158
LOG(NDD)	0.550	3.308
LOG(TIME)	-0.206	-5.845
LOG(TMAN)	1.168	6.297
LOG(REAL_NRC_CPG)	-0.295	-3.229
DUM97	0.240	3.937
F Statistic	14.779	
Adjusted R-squared	0.775	
S.E. of regression	0.056	

Short Run Equation

Variable	Coefficient	t-Statistic
C	-0.034	-2.318
DLOG(NDD)	0.737	6.183
DLOG(TMAN)	0.796	2.962
DLOG(REAL_NRC_CPG)	-0.203	-2.103
DUM97	0.290	4.905
ECM_NRC73(-1)	-0.743	-2.745
F Statistic	15.056	
Adjusted R-squared	0.787	
S.E. of regression	0.055	

TABLE 4

DRIVER VARIABLE ASSUMPTIONS

Col 1.	Col 2.	Col 3.	Col 4.	Col 5.	Col 6.	Col 7.	Col 8.
Fiscal Year	2002	2003	2004	2005	2006F	2007F	2008F
Central Heating Degree Days [1]	2,566 -13.3%	3,212 25.2%	2,947 -8.2%	2,952 0.2%	2,648 -10.3%	2,743 3.6%	2,708 -1.3%
Eastern Heating Degree Days	3,108 -13.4%	3,857 24.1%	3,612 -6.4%	3,599 -0.4%	3,249 -9.7%	3,405 4.8%	3,384 -0.6%
Niagara Heating Degree Days	2,423 -15.3%	3,079 27.1%	2,810 -8.7%	2,858 1.7%	2,558 -10.5%	2,735 7.0%	2,718 -0.6%
Central Weather Zone Employment	1.8%	3.6%	2.6%	1.2%	2.8%	2.7%	2.5%
Eastern Weather Zone Employment	-0.2%	4.1%	-0.1%	1.3%	2.2%	2.1%	2.2%
Real Commercial Natural Gas Price	-24.2%	15.9%	2.6%	9.8%	15.2%	9.6%	9.4%
Ontario Real Retail Sales	3.4%	1.5%	0.4%	3.1%	1.7%	2.3%	2.5%
Ontario Real Gross Domestic Product	2.3%	2.1%	2.9%	2.4%	2.4%	2.5%	2.8%
Ontario Goods Producing Industry Real Domestic Product	1.3%	1.1%	3.2%	2.0%	2.9%	3.9%	4.4%
Ontario Manufacturing Industry Real Domestic Product	-0.2%	0.5%	4.1%	2.2%	3.3%	3.8%	4.4%

[1] Degree days are balance point meter reading heating degree days (adjusted for billing cycle). Heating degree days for fiscal year 2006 are calculated using actual heating degree days (October 2005 to March 2006) and Board Approved heating degree days (April 2006 to September 2006). Heating degree days for fiscal year 2007 are calculated using Board Approved degree days (October 2006 to December 2006) and the Company's heating degree day forecast (January 2007 to September 2007). Heating degree days for fiscal year 2008 are the Company's forecast heating degree days.

Summary Statistics

11. Table 5 shows the results that the models would generate for Rate 6 average use using actual 2005 data to allow parties to compare the results to the prior year's forecast. Note that Table 5 is not updated for 2004 since a 2004 Board Approved normalized average use forecast is not available. In order to compare the variance between normalized actual and Board Approved average use on the same basis, the actual results for each year have to be normalized to the corresponding Board Approved degree days for that year. The 2005 actual average use has been normalized to the 2005 Board Approved degree days for that year, 3747. The Board Approved normalized average use per customer, Column 3, are the forecasts filed in RP-2003-0203. The model's normalized average use per customer, Column 6, was generated using all actual data up to and including Fiscal 2005 data. The five years results show that the model's forecast of historical average use does

Appendix 1

Mnemonics of the variables in the model are defined as follows:

Mnemonic	Definition
C	Constant Term
LOG(X)	Logarithm of Variable X
DLOG(X)	$LOG(X_t)$ - $LOG(X_{t-1})$
CDD, EDD, NDD	Balance Point Heating Degree Days for Central, Eastern and Niagara Weather Zones
MET20_VINT	Vintage Variable for the Metro Region, Central Weather Zone
WES20_VINT	Vintage Variable for the Western Region, Central Weather Zone
CEN20_VINT	Vintage Variable for the Central Region, Central Weather Zone
NOR20_VINT	Vintage Variable for the Northern Region, Central Weather Zone
ERC20_VINT	Vintage Variable for the Eastern Weather Zone
NRC20_VINT	Vintage Variable for the Niagara Weather Zone
REAL_CRC_RPG	Real Residential Natural Gas Price for the Central Weather Zone
REAL_ERC_RPG	Real Residential Natural Gas Price for the Eastern Weather Zone
REAL_NRC_RPG	Real Residential Natural Gas Price for the Niagara Weather Zone
TIME	Time Trend
CRCE	Central Weather Zone Employment
ECM_Region	Error Correction Term for Each Region

Appendix 2

Regression results are as follows:

Metro Region - Central Weather Zone

Long Run Equation

Variable	Coefficient	t-Statistic
C	-0.548	-2.059
LOG(CDD)	0.713	20.638
LOG(REAL_CRC_RPG)	-0.091	-3.707
LOG(MET20_VINT)	0.223	1.807
LOG(TIME)	-0.021	-2.293
F Statistic	276.582	
Adjusted R-squared	0.982	
S.E. of regression	0.011	

Short Run Equation

Variable	Coefficient	t-Statistic
C	-0.005	-2.451
DLOG(CDD)	0.748	31.838
DLOG(REAL_CRC_RPG)	-0.097	-4.740
ECM_MET20(-1)	-0.551	-2.132
F Statistic	419.043	
Adjusted R-squared	0.985	
S.E. of regression	0.010	

Western Region - Central Weather Zone

Long Run Equation

Variable	Coefficient	t-Statistic
C	-1.300	-2.108
LOG(CDD)	0.711	22.730
LOG(REAL_CRC_RPG)	-0.115	-8.296
LOG(WES20_VINT)	0.177	4.526
LOG(CRCE)	0.083	1.245
F Statistic	316.337	
Adjusted R-squared	0.984	
S.E. of regression	0.011	

Short Run Equation

Variable	Coefficient	t-Statistic
C	-0.004	-1.773
DLOG(CDD)	0.726	32.110
DLOG(REAL_CRC_RPG)	-0.119	-5.939
ECM_WES20(-1)	-0.701	-2.742
F Statistic	392.831	
Adjusted R-squared	0.984	
S.E. of regression	0.010	

Central Region - Central Weather Zone

Long Run Equation

Variable	Coefficient	t-Statistic
C	-2.764	-3.168
LOG(CDD)	0.709	16.413
LOG(REAL_CRC_RPG)	-0.111	-3.249
LOG(CEN20_VINT)	0.251	5.671
LOG(CRCE)	0.266	2.792
LOG(TIME)	-0.017	-1.233
F Statistic	179.047	
Adjusted R-squared	0.978	
S.E. of regression	0.014	

Short Run Equation

Variable	Coefficient	t-Statistic
C	-0.001	-0.199
DLOG(CDD)	0.707	23.123
DLOG(REAL_CRC_RPG)	-0.084	-2.814
DLOG(CEN20_VINT)	0.155	1.177
ECM_CEN20(-1)	-1.156	-4.322
F Statistic	173.929	
Adjusted R-squared	0.973	
S.E. of regression	0.013	

Northern Region - Central Weather Zone

Long Run Equation

Variable	Coefficient	t-Statistic
C	-2.170	-3.358
LOG(CDD)	0.728	21.514
LOG(REAL_CRC_RPG)	-0.109	-7.291
LOG(NOR20_VINT)	0.241	8.195
LOG(CRCE)	0.186	2.628
F Statistic	405.577	
Adjusted R-squared	0.988	
S.E. of regression	0.011	

Short Run Equation

Variable	Coefficient	t-Statistic
C	-0.001	-0.116
DLOG(CDD)	0.724	28.898
DLOG(REAL_CRC_RPG)	-0.113	-4.314
DLOG(NOR20_VINT)	0.143	1.469
ECM_NOR20(-1)	-1.071	-4.156
F Statistic	238.417	
Adjusted R-squared	0.980	
S.E. of regression	0.011	

Eastern Weather Zone

Long Run Equation

Variable	Coefficient	t-Statistic
C	-1.533	-4.343
LOG(EDD)	0.801	17.726
LOG(REAL_ERC_RPG)	-0.123	-4.993
LOG(ERC20_VINT)	0.114	2.946
LOG(TIME)	-0.024	-2.486

F Statistic	247.257	
Adjusted R-squared	0.980	
S.E. of regression	0.012	

Short Run Equation

Variable	Coefficient	t-Statistic
C	-0.008	-2.593
DLOG(EDD)	0.821	25.144
DLOG(REAL_ERC_RPG)	-0.126	-4.547
ECM_ERC20(-1)	-1.069	-3.904

F Statistic	224.601	
Adjusted R-squared	0.972	
S.E. of regression	0.013	

Niagara Weather Zone

Long Run Equation

Variable	Coefficient	t-Statistic
C	-0.317	-0.798
LOG(NDD)	0.668	13.040
LOG(REAL_NRC_RPG)	-0.104	-2.707
LOG(TIME)	-0.034	-2.334
LOG(NRC20_VINT)	0.334	1.758
F Statistic	125.634	
Adjusted R-squared	0.961	
S.E. of regression	0.018	

Short Run Equation

Variable	Coefficient	t-Statistic
C	-0.009	-2.592
DLOG(NDD)	0.624	18.439
DLOG(REAL_NRC_RPG)	-0.042	-1.314
ECM_NRC20(-1)	-1.043	-3.947
F Statistic	169.678	
Adjusted R-squared	0.964	
S.E. of regression	0.016	

the weather impact has been taken out. Using the estimated coefficients, weather normalized average use data are obtained by replacing actual degree days in the model with budgeted degree days for fiscal 2007.

Data – Driver Variables

13. Driver variable assumptions are presented in Table 2 in year over year growth rates. Major driver variables in the model are balance point heating degree days adjusted for billing cycles, vintage, time trend, real energy prices, and economic variables. The driver variable assumptions are based on economic assumptions from the *Economic Outlook, Winter 2006* which can be found at Exhibit C1, Tab 1, Schedule 1.

TABLE 2

DRIVER VARIABLE ASSUMPTIONS

Col 1.	Col 2.	Col 3.	Col 4.	Col 5.	Col 6.	Col 7.	Col 8.
Fiscal Year	2002	2003	2004	2005	2006F	2007F	2008F
Central Heating Degree Days [1]	2,566	3,212	2,947	2,952	2,648	2,743	2,708
	-13.3%	25.2%	-8.2%	0.2%	-10.3%	3.6%	-1.3%
Eastern Heating Degree Days	3,108	3,857	3,612	3,599	3,249	3,405	3,384
	-13.4%	24.1%	-6.4%	-0.4%	-9.7%	4.8%	-0.6%
Niagara Heating Degree Days	2,423	3,079	2,810	2,858	2,558	2,735	2,718
	-15.3%	27.1%	-8.7%	1.7%	-10.5%	7.0%	-0.6%
Real Residential Natural Gas Price	-21.2%	15.0%	2.1%	8.5%	13.4%	8.5%	8.5%
Central Weather Zone Employment	1.8%	3.6%	2.6%	1.2%	2.8%	2.7%	2.5%
Vintage: Metro Region, Central Wether Zone	-1.1%	-1.4%	-1.1%	-0.9%	-0.9%	-0.9%	-0.9%
Vintage: Western Region, Central Weather Zone	-4.3%	-4.6%	-3.9%	-3.4%	-3.3%	-3.2%	-3.1%
Vintage: Central Region, Central Weather Zone	-3.3%	-4.1%	-4.0%	-3.6%	-3.6%	-3.5%	-3.4%
Vintage: Northern Region, Central Weather Zone	-5.4%	-5.0%	-4.8%	-3.6%	-3.4%	-3.2%	-3.0%
Vintage: Eastern Weather Zone	-3.4%	-3.6%	-3.7%	-3.1%	-3.0%	-2.9%	-2.8%
Vintage: Niagara Weather Zone	-1.2%	-1.4%	-1.5%	-1.4%	-1.4%	-1.4%	-1.4%

[1] Degree days are balance point meter reading heating degree days (adjusted for billing cycle). Heating degree days for fiscal year 2006 are calculated using actual heating degree days (October 2005 to March 2006) and Board Approved heating degree days (April 2006 to September 2006). Heating degree days for fiscal year 2007 are calculated using Board Approved degree days (October 2006 to December 2006) and the Company's heating degree day forecast (January 2007 to September 2007). Heating degree days for fiscal year 2008 are the Company's forecast heating degree days.

ECONOMIC OUTLOOK WINTER 2006

CANADA & U.S.

CALENDAR YEAR[1]	2002	2003	2004	2005	2006F	2007F
REAL GDP (% CHANGE)						
CANADA	3.1	2.0	2.9	2.8	3.0	3.1
U.S.	1.6	2.7	4.2	3.6	3.5	3.0
REAL CONSUMPTION (% CHANGE)	3.7	3.1	3.4	3.9	3.0	2.9
REAL INVESTMENT (% CHANGE)						
BUSINESS	0.7	6.2	6.9	7.0	5.1	3.8
NON-RESIDENTIAL CONSTRUCTION	-7.3	5.7	0.8	7.0	6.8	4.0
MACHINERY & EQUIPMENT	-3.3	6.4	9.8	10.4	8.6	6.3
RESIDENTIAL CONSTRUCTION	14.3	6.2	8.3	3.6	0.2	0.8
REAL EXPORTS (% CHANGE)	1.0	-2.1	5.0	2.7	3.1	3.6
REAL IMPORTS (% CHANGE)	1.5	4.1	8.1	7.1	3.6	3.3
HOUSING STARTS (000's)	205	218	233	223	192	185
UNEMPLOYMENT RATE (%)	7.7	7.6	7.2	6.7	6.7	6.9
EMPLOYMENT GROWTH (% CHANGE)	2.4	2.3	1.8	1.4	1.7	1.7
CONSUMER PRICES (% CHANGE)						
CANADA	2.2	2.8	1.8	2.4	2.5	2.0
U.S.	1.6	2.3	2.7	3.3	3.0	2.6

[1] Throughout this exhibit ‘Fiscal’ refers to the year ending September 30, while ‘Calendar’ refers to the year ending December 31.

ONTARIO

CALENDAR YEAR	2002	2003	2004	2005	2006F	2007F
REAL GDP (% CHANGE)	3.0	1.8	3.0	2.6	2.3	2.5
GOODS	3.0	0.6	3.4	2.0	2.9	4.3
MANUFACTURING	2.6	0.1	4.4	2.1	3.2	4.2
SERVICE	2.9	2.3	2.8	3.0	2.7	3.0
REAL CONSUMPTION (% CHANGE)	3.9	3.2	3.3	3.3	2.7	3.1
HOUSING STARTS (000's)	83.6	85.2	85.1	78.8	70.9	75.7
UNEMPLOYMENT RATE (%)	7.1	6.9	6.8	6.6	6.4	6.7
EMPLOYMENT GROWTH (% CHANGE)	1.9	2.9	1.7	1.3	1.6	1.9
CONSUMER PRICES (% CHANGE)	2.0	2.7	1.9	2.2	2.3	2.0
REAL RETAIL SALES (% CHANGE)	3.7	0.7	1.3	2.8	1.6	2.5
WAGE RATE (% CHANGE)	1.2	0.9	1.4	3.0	3.6	2.7

REGIONS

CALENDAR YEAR	2002	2003	2004	2005	2006F	2007F
GTA						
HOUSING STARTS (000's)	46.2	48.1	44.7	43.0	39.3	38.8
SINGLES	25.0	22.3	21.5	17.7	16.9	17.5
MULTIPLES	21.2	25.8	23.2	25.4	22.4	21.2
CONSUMER PRICES (% CHANGE)	2.1	3.0	1.7	1.8	2.1	1.9
UNEMPLOYMENT RATE (%)	7.1	7.1	6.8	6.8	6.7	6.7
EMPLOYMENT GROWTH (% CHANGE)	2.1	3.4	2.3	1.8	2.6	2.6
EASTERN						
HOUSING STARTS (000's)	8.0	7.1	7.5	5.2	5.7	6.2
SINGLES	3.9	3.7	3.5	2.5	2.7	3.0
MULTIPLES	4.1	3.4	4.0	2.6	3.0	3.1
CONSUMER PRICES (% CHANGE)	2.1	2.5	1.9	2.3	2.3	2.0
UNEMPLOYMENT RATE (%)	7.3	6.9	6.6	6.7	6.6	6.5
EMPLOYMENT GROWTH (% CHANGE)	0.3	3.9	-0.7	1.7	2.2	2.4
NIAGARA						
HOUSING STARTS (000's)	1.4	1.8	2.0	1.5	1.4	1.5
SINGLES	1.1	1.3	1.5	1.1	1.0	1.1
MULTIPLES	0.3	0.5	0.6	0.4	0.4	0.4
UNEMPLOYMENT RATE (%)	7.3	7.0	7.3	7.0	6.6	6.6
EMPLOYMENT GROWTH (% CHANGE)	1.1	1.8	-2.5	3.1	0.8	1.2

CANADA & U.S.

FISCAL YEAR	2002	2003	2004	2005	2006F	2007F	2008F
REAL GDP (% CHANGE)							
CANADA	2.5	2.5	2.5	3.0	2.8	3.2	3.0
U.S.	1.2	2.2	4.3	3.7	3.6	3.1	3.2
REAL CONSUMPTION (% CHANGE)	3.2	3.4	3.1	4.0	3.0	3.0	2.9
REAL INVESTMENT (% CHANGE)							
BUSINESS	0.0	4.8	7.7	6.7	5.7	4.0	2.6
NON-RESIDENTIAL CONSTRUCTION	-4.4	1.5	3.2	4.4	7.7	4.9	0.0
MACHINERY & EQUIPMENT	-6.6	5.0	10.1	10.4	9.0	6.7	5.8
RESIDENTIAL CONSTRUCTION	14.6	7.2	8.5	4.7	1.0	0.4	1.2
REAL EXPORTS (% CHANGE)	-0.8	-1.7	4.2	2.4	3.4	3.4	3.9
REAL IMPORTS (% CHANGE)	-2.2	4.3	7.5	7.9	4.2	3.2	3.4
HOUSING STARTS (000's)	195	215	230	229	199	186	181
UNEMPLOYMENT RATE (%)	7.7	7.6	7.3	6.9	6.6	6.9	6.9
EMPLOYMENT GROWTH (% CHANGE)	1.7	2.7	1.9	1.4	1.6	1.7	1.5
CONSUMER PRICES (% CHANGE)							
CANADA	1.6	3.3	1.7	2.2	2.6	2.1	2.0
U.S.	1.5	2.4	2.3	3.3	3.3	2.6	2.6

ONTARIO

FISCAL YEAR	2002	2003	2004	2005	2006F	2007F	2008F
REAL GDP (% CHANGE)	2.3	2.1	2.9	2.4	2.4	2.5	2.8
GOODS	1.3	1.1	3.2	2.0	2.9	3.9	4.4
MANUFACTURING	-0.2	0.5	4.1	2.2	3.3	3.8	4.4
SERVICE	2.8	2.5	2.8	2.7	2.8	3.0	3.0
REAL CONSUMPTION (% CHANGE)	3.3	4.0	2.5	3.8	2.5	3.1	3.1
HOUSING STARTS (000's)	81.5	84.0	85.9	80.8	71.3	75.0	77.8
UNEMPLOYMENT RATE (%)	7.1	7.0	6.8	6.7	6.4	6.6	6.8
EMPLOYMENT GROWTH (% CHANGE)	1.2	3.3	1.8	1.3	1.5	2.0	1.8
CONSUMER PRICES (% CHANGE)	1.7	2.9	1.9	2.2	2.2	2.2	2.0
REAL RETAIL SALES (% CHANGE)	3.4	1.5	0.4	3.1	1.7	2.3	2.5
WAGE RATE (% CHANGE)	1.3	1.0	1.3	2.0	4.5	2.5	2.7

REGIONS

FISCAL YEAR	2002	2003	2004	2005	2006F	2007F	2008F
GTA							
HOUSING STARTS (000's)	46.3	47.0	46.2	43.7	38.8	39.6	38.7
SINGLES	24.4	22.9	22.3	18.3	16.6	17.8	17.6
MULTIPLES	21.9	24.1	23.9	25.4	22.2	21.9	21.1
CONSUMER PRICES (% CHANGE)	1.8	3.2	1.9	1.7	2.0	2.1	1.8
UNEMPLOYMENT RATE (%)	6.9	7.1	6.8	7.0	6.7	6.7	6.7
EMPLOYMENT GROWTH (% CHANGE)	1.8	3.6	2.6	1.2	2.8	2.7	2.5
EASTERN							
HOUSING STARTS (000's)	7.4	6.7	7.9	5.7	5.6	6.0	6.6
SINGLES	3.7	3.1	4.1	2.7	2.6	2.9	3.3
MULTIPLES	3.7	3.5	3.8	3.0	3.0	3.1	3.3
CONSUMER PRICES (% CHANGE)	1.7	2.8	1.9	2.2	2.2	2.2	2.0
UNEMPLOYMENT RATE (%)	7.2	6.9	6.9	6.7	6.5	6.5	6.5
EMPLOYMENT GROWTH (% CHANGE)	-0.2	4.1	-0.1	1.3	2.2	2.1	2.2
NIAGARA							
HOUSING STARTS (000's)	1.3	1.7	2.1	1.5	1.4	1.5	1.6
SINGLES	1.1	1.3	1.4	1.2	1.0	1.1	1.2
MULTIPLES	0.2	0.5	0.7	0.3	0.4	0.4	0.4
UNEMPLOYMENT RATE (%)	6.9	7.1	7.5	6.8	6.6	6.6	6.6
EMPLOYMENT GROWTH (% CHANGE)	-0.1	2.2	-2.3	3.6	-0.4	1.8	0.9

Witness: J. Denomy

GAS VOLUME BUDGET

1. The purpose of this evidence is to present the 2007 Test Year volume budget and request the Board's approval of the volumes as summarized in Table 1. The information shown in this evidence is on a calendar-year basis (i.e., on a December 31 year end) excluding the Historical Actual vs. Board Approved section. The Test Year Budget includes calendar 2005 actual consumption information up to and including December 2005.

2. A summary of the volumes, customers, and revenues is provided below in Table 1. Further detail is provided at Exhibit C3, Tab 2, Schedule 1; Exhibit C4, Tab 2, Schedule 1; Exhibit C4, Tab 2, Schedule 5; and Exhibit C5, Tab 2, Schedule 1.

Table 1
Summary of Gas Sales and Transportation
Volumes, Customers and Revenues
(Volumes in 10^6m^3)

	Calendar 2005 Actual	Calendar 2006 Board Approved Budget	Calendar 2006 Bridge Year Estimate	Calendar 2007 Budget
General Service Volumes	8 019.5	7 932.8	7 758.6	7 625.8
Contract Volumes	4 190.3	4 387.9	4 116.5	4 131.7
Total Volumes, Gas Sales and Transportation	12 209.8	12 320.7	11 875.1	11 757.5
Customers, Gas Sales and Transportation (Average)	1 735 907	1 792 615	1 780 459	1 823 258
Revenues, Gas Sales and Transportation ($ Millions)	3 064.4	3 091.3	3 348.8	3 072.3

Witnesses: I. Chan
T. Ladanyi

3. This evidence has divided into the following sections:
    - Comparison of 2007 Budget and 2006 Estimate
    - Evaluation of Forecast Accuracy – Historical Normalized Actual vs. Board Approved Budget
    - Demand Forecast Methodology
    - Comparison of 2006 Estimate and 2005 Actual
    - Comparison of 2006 Estimate and 2006 Board Approved
    - Weather Normalization Methodology

Comparison of 2007 Budget and 2006 Estimate

4. The 2007 volume budget reflects the meter reading heating degree day forecast of 3,617, a decrease of 128 degree days compared to the 2006 Bridge Year Estimate of 3,745. Meter reading heating degree days are acquired by amalgamating Gas Supply heating degree days with the billing schedules. Evidence related to the forecast of Gas Supply heating degree days is presented at Exhibit C2, Tab 4, Schedule 1. The test year degree day forecast has been developed using the proposed 20 Year Trend methodology as it produces the best fit in the Company's analysis and comprehensive review of competing degree day forecasting methods.

5. The 2007 volumes budget of 11 757.5 10^6m^3 are 117.6 10^6m^3 or 1.0% below the 2006 Bridge Year Estimate of 11 875.1 10^6m^3. On a weather-normalized basis, the 2007 Budget volumes are forecast to be 90.3 10^6m^3 or 0.8% above the 2006 Bridge Year Estimate. The increase on a normalized basis is made up of an increase in general service volumes of 44.7 10^6m^3 and an increase in the contract market of

45.6 10^6m^3. Further rate class detail and explanation are provided at Exhibit C3, Tab 2, Schedule 3.

6. The increase in the general service volumes of 44.7 10^6m^3 on a weather-normalized basis is primarily due to customer growth of 140.3 10^6m^3 and incremental added load initiatives of 3.6 10^6m^3 as described in the Opportunity Development evidence at Exhibit D1, Tab 8, Schedule 1. These additional volumes mitigate the lower average use per customer of 99.0 10^6m^3 as a result of the Company's initiatives, customers' own conservation initiatives and high natural gas prices.[1] Further explanations are provided in the average use section on the next page. Further numerical details are provided at Exhibit C3, Tab 2, Schedule 3.

7. The increase of 45.6 10^6m^3 in the contract market on a weather-normalized basis is primarily due the addition of two large customers in 2007, the incremental load of an existing customer, and the full operational capacity of several new large customers added in 2006 and existing customers; partially offset by a loss in load due to two industrial plant closures in the Food and Beverage sector and the loss of theToronto Transit Commission ("TTC") as a customer due to its discontinued use of Natural Gas Vehicles ("NGV") for buses starting in 2006. Further details are provided at Exhibit C3, Tab 2, Schedule 3. Overall, the 2007 budget represents the forecast that integrates all of the actual experiences and the best known information about contract customers at the time the budget was developed.

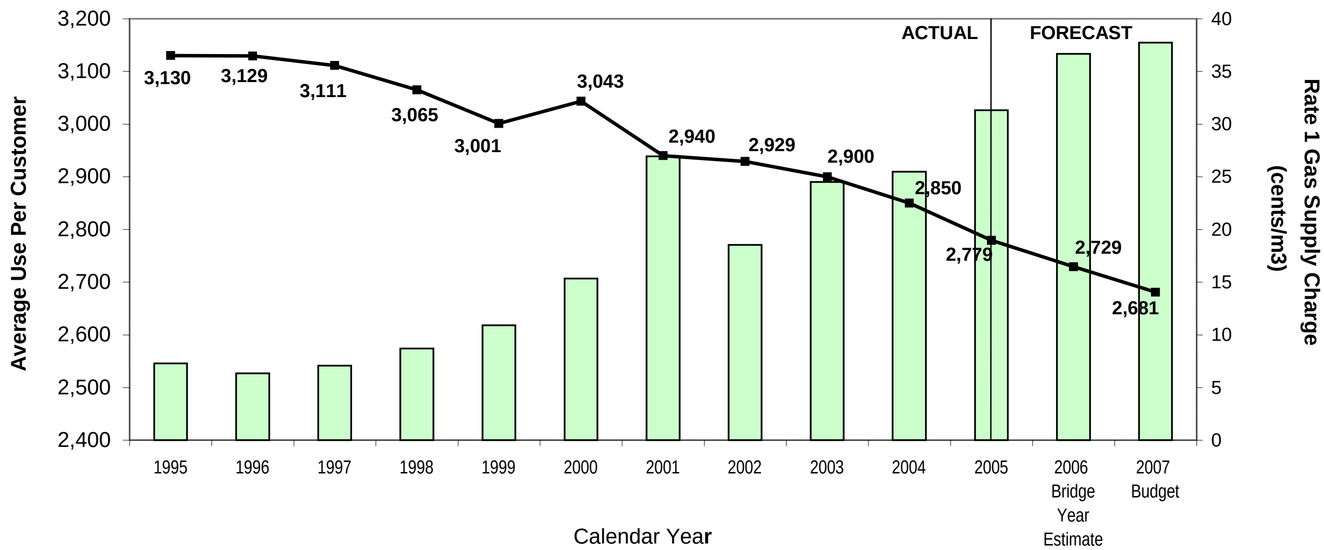
<u>General Service Average Use: 2007 Budget</u>

8. From 1995 to 2005, normalized residential average use has declined by an average of 35.0 m^3 or 1.2% per year. However, during the volatile and high natural gas price

[1] Real Residential Natural Gas Price – Table 2- Exhibit C2, Tab 3, Schedule 1.

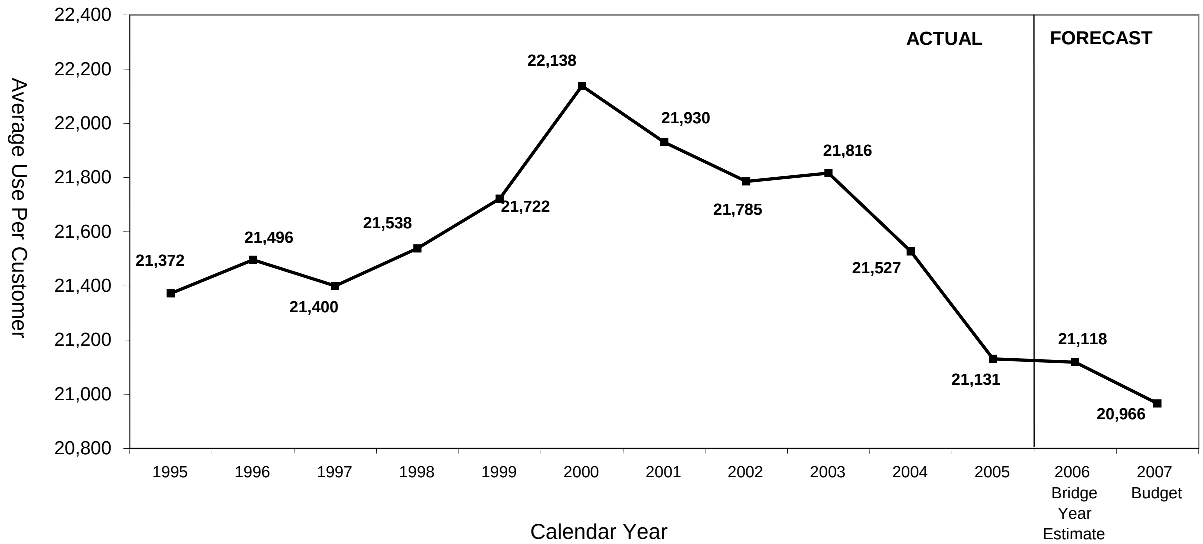
period between 2001 and 2005, normalized residential average use has decreased by an average of 53 m³ or 1.8% per year. Figure 1 shows the residential average use from 1995 to the 2007 Test Year on a test year weather normalized basis, as filed at Exhibit C5, Tab 2, Schedule 3.

Figure 1
Residential Normalized Average Use (m^3)



9. Similarly, from 1995 to 2005, normalized Rate 6 average use has decreased by an average of 24.0 m^3 or 0.11% per year. During the period between 2001 and 2005, normalized Rate 6 average use has decreased by an average of 201 m^3 or 0.9% per year. Figure 2 on the next page shows the Rate 6 average use from 1995 to the 2007 Test Year on a test year weather normalized basis, as filed at Exhibit C5, Tab 2, Schedule 3. Rate 6 is comprised of the apartment, commercial, and industrial sectors.

Figure 2
Rate 6 Normalized Average Use (m^3)



10. Tables 3 to 6 have been developed in response to previous years' interrogatories by quantifying the impact of the average use's driver variables on the system-wide average use forecast by sector.

11. Compared with the 2006 Bridge Year Estimate, residential average uses is expected to continue to decline in 2007. This decline is due to the expectation of higher gas prices in 2007 than in 2006 based on experience in recent years, the Company's DSM initiatives, new homes with improved thermal envelopes and higher efficiencies on new heating and water heating equipment, and other conservation iniatives; partially offset by the Company's added load initiatives and the penetration of new gas appliances as a result of moderate employment growth in 2007. Other conservation captures the historical reduction in volumes due to the impact of conservation activities on average uses; such as the ongoing gas equipment efficiency effect as a result of the replacement of old equipment with

medium or high efficiency furnaces, increased energy efficiency of new gas-fired water heaters effective September 1, 2004, continued home renovation efforts in older building, and conservation initiatives originated by customers themselves or as a result of government programs.

12. Residential average uses are significantly affected by gas prices. Customers respond to a sharp price increase in various ways, such as lowering thermostat controls and adding additional layers of clothing, purchasing more efficient gas furnaces, appliances and/or programmable thermostats, or by renovating their homes to make them more energy efficient. Together with increasing gas prices in 2006 which were higher than the increase that occurred in 2001, forecasts of higher real natural gas prices in 2007 will continue to drive a decrease in the average use in 2007 at a similar trend as experienced in the 2001 to 2005 actuals.

13. Apartment sector average uses is expected to decrease in 2007, primarily due to the Company's DSM initiatives, conservation initiatives originated by customers or a result of government programs, and higher gas prices in 2007; partially offset by moderate employment growth.

14. Commercial sector average uses are expected to continue to decrease in 2007, primarily due to Company's DSM initiatives, other conservation, and higher gas prices in 2007; partially offset by still moderate employment growth and the Company's Utility Growth Plan initiatives. Other conservation captures the historical reduction in volumes due to the impact of conservation activities on average uses; such as continued conservation efforts in older buildings, improved thermal envelopes for newer buildings, higher efficiencies of new heating and water heating

equipment, and self-imposed conservation activities either initiated by customers or as a result of government programs.

15. Industrial sector average uses are expected to increase in 2007, primarily due to moderate economic growth and customer migration from contract rates to general service rates; partially offset by the Company's Utility Growth Plan initiatives, higher gas prices in 2007, and other conservation. Other conservation captures the reduction in volumes due to the impact of conservation activities on average uses; such as a change in production process, improved thermal envelopes for newer buildings, higher efficiencies on new heating and water heating equipments, and self-imposed conservation activities either initiated by the customers or as a result of government programs.

16. Trends in this sector have been variable over time. Economic conditions and rate switching have also played a significant role in recent years' industrial average uses as this sector is affected by the restructuring of large contract customers, fluctuations in product demand and changes in production process. In 2005 and 2006, there were a number of industrial customers that switched from contract rates to general service rates who are not expected to switch back in 2007 as a result of their consumption not meeting the minimum threshold requirement of 340,000 m^3 for contract customers. There are a variety of reasons that the customers may not meet the minimum threshold, such as customers embracing DSM or conservation initiatives, winding down industrial plants, changes in production process to enhance efficiency, and plant consolidation.

Table 3

Factors Influencing the Changes in Residential Gas Consumption
Between 2007 Test Year Budget and 2006 Bridge Year Estimate ($10^6 m^3$)

Factors	Total Volume ($10^6 m^3$)	
DSM Initiatives	(11.8)	
New Homes (a)	(6.4)	
Other Conservation (b)	(14.9)	
Gas Prices	(48.6)	
Gas Appliances (c)	0.0	*
Growth Initiatives or Added Load (d)	3.4	
Total	(78.3)	

(a) Measured by vintage variable as explained at Exhibit C2, Tab 3, Schedule 1, reflecting the historical impacts of improved building envelopes for new homes along with more efficient new space heating furnaces and water heaters on average uses.

(b) Other Conservation includes the expected ongoing technology improvements of furnaces for the existing homes, new more energy efficient gas-fired storage water heaters effective September 1, 2004, and conservation initiatives originated by customers or as a result of by government programs, such as programmable thermostats, low-flow showerheads, and home renovations..

(c) Measured by employment variable to reflect the demand for Gas Appliances or Gas Technologies.

(d) Added Load is based on the Company's Utility Growth Plan initiatives developed by the Opportunity Development group. See Exhibit D1, Tab 8, Schedule 1, for detailed information about these added load programs.

* Less than 50,000 m^3

Witnesses: I. Chan
T. Ladanyi

Table 4

Factors Influencing the Changes in Apartment Gas Consumption

Between 2007 Test Year Budget and 2006 Bridge Year Estimate (10^6 m^3)

Factors	Total Volume ($10^6 m^3$)	
DSM Initiatives	(2.7)	
Economics, Gas Appliances (a)	1.4	
Other Conservation (b)	0.0	*
Gas Prices	(2.5)	
Growth Initiatives or Added Load (c)	0.0	
Total	(3.8)	

(a) Measured by economic variables as explained at Exhibit C2, Tab 3, Schedule 2, to reflect the demand for Gas Appliances or Gas Technologies, to capture the historical actual average trend of the apartment's sector average use, such as transfer gains/losses impact on average uses, vacancy rate, and construction trend.

(b) Other Conservation includes the expected ongoing technology improvements of furnaces, and conservation initiatives originated by customers or as a result of government programs, such as programmable thermostats, improved building envelopes, low-flow showerheads, and building renovations.

(c) Added Load is based on the Company's Utility Growth Plan initiatives developed by the Opportunity Development group. See Exhibit D1, Tab 8, Schedule 1, for detailed information about these added load programs.

* Less than 50,000 m^3

Witnesses: I. Chan
T. Ladanyi

Table 5

Factors Influencing the Changes in Commercial Gas Consumption

Between 2007 Test Year Budget and 2006 Bridge Year Estimate ($10^6 m^3$)

Factors	Total Volume ($10^6 m^3$)
DSM Initiatives	(11.7)
Economics, Gas Appliances (a)	4.8
Other Conservation (b)	(6.4)
Gas Prices	(0.6)
Growth Initiatives or Added Load (c)	0.2
Total	(13.7)

(a) Economics variables are used to measure the demand for Gas Appliances or Gas Technologies, to capture the historical actual average trend of the commercial's sector average use, such as transfer gains/losses impact on average uses, vacancy rate, and construction trend.

(b) Other Conservation includes the expected ongoing technology improvements of furnaces, and conservation initiatives originated by customers or as a result of government programs, such as programmable thermostats, improved building envelopes, office space requirements, and building renovations.

(c) Added Load is based on the Company's Utility Growth Plan initiatives developed by the Opportunity Development group. See Exhibit D1, Tab 8, Schedule 1, for detailed information about these added load programs.

Witnesses: I. Chan
T. Ladanyi

Table 6

Factors Influencing the Changes in Industrial Gas Consumption

Between 2007 Test Year Budget and 2006 Bridge Year Estimate ($10^6 m^3$)

Factors	Total Volume ($10^6 m^3$)
DSM Initiatives	(1.4)
Economics, Gas Appliances (a)	2.7
Other Conservation (b)	(0.6)
Gas Prices	(0.3)
Growth Initiatives or Added Load (c)	0.0
Total	0.4

(a) Economics variables are used to measure the demand for Gas Appliances or Gas Technologies, to capture the historical actual average trend of the industrial sector average use, such as transfer gains/losses impact on average uses, vacancy rate, and construction trend.

(b) Other Conservation includes the technology improvements of furnaces, and self-imposed conservation activities, such as change in process, programmable thermostats, improved building envelopes, and building renovations.

(c) Added Load is based on the Company's Utility Growth Plan initiatives developed by the Opportunity Development group. See Exhibit D1, Tab 8, Schedule 1, for detailed information about these added load programs.

Witnesses: I. Chan
T. Ladanyi

BOARD STAFF INTERROGATORY #17

INTERROGATORY

Ref: C2/T4/S1

Issue Number: 2.3
Issue: Is the forecast of degree days appropriate?

a) If one assumes increasing weather volatility is an important factor to consider in forecasting degree days, does the data contained in C2/T4/S1/page12/table8 "Out-of-sample Forecast Performance, Recent Five Year Period (2001 to 2005)" support a conclusion that the "Energy Probe" method is the most appropriate method to forecast degree days?

b) For each of "20-yr Trend", "Energy Probe", "de Bever" and "de Bever with Trend" degree days forecast methodologies , please complete the table below:

	20-yr Trend	Energy Probe	de Bever	de Bever with Trend
Total operating costs incurred by EGDI in utilizing the method				
Total bill impact on a typical residential customer (%)				
Impact on revenue requirement (%)				

RESPONSE

a) Increasing weather volatility is an important factor to consider in forecasting degree days. It should be noted that for the periods examined by the Company in Exhibit C2, Tab 4, Schedule 1, page 4, Table 3, the ten-year period from 1996 to 2005 was the most volatile period for Central Area degree days. During the 1996 to 2005 period the standard deviation of Central Area degree days was 313.5. While the Company has not examined the volatility of degree days over a 5 year period it should be noted that the 20-Year Trend method, as per Exhibit C2, Tab 4, Schedule 1, page 11, Table 7 ranks best over the 1996 to 2005 period which coincides to the most volatile period for Central Area degree days.

Witnesses: I. Chan
J. Collier
K. Culbert
J. Denomy
T. Ladanyi

b) The Company has received a number of interrogatories requesting production of numerous different degree-day scenarios in different formats. Due to the amount of effort required, the Company has consolidated these different degree-day scenarios into one response.

It should be noted that the volumetric changes associated with changing the Company's test year budget degree days of 3,617 to the requested levels reviewed herein, could lead to other adjustments to be undertaken in the gas supply, transportation, and storage operating departments. Curtailment volumes, commodity purchases, unaccounted for gas, storage levels, and transportation (utilization) would all be impacted. As a result, the Company is reluctant to provide this "short-cut" response without expressing concern regarding risks of such potentially significant consequences. Furthermore, as shown in Exhibit C2, Tab 4, Schedule 1, the proposed 20-year trend methodology maintains superior performance relative to other alternatives rendering such "short-cut" responses moot.

With the understanding that a "short-cut" response is an approximation inclusive of the assumption that the volume increases would be the sole driver of a requirement/sufficiency/deficiency change, the Company provides the following calculations.

Table 1 on the next page illustrates the requested operating costs incurred (Item 1.1), percent of both total bill (Item 1.2) and delivery charge (Item 1.3) impact on a typical annualized total customer bill impact, both percent (Item 1.4) and level impact (Item 1.5) on revenue requirement, and volumetric impact (Item 1.6) under each of the reviewed degree days forecasting methodology shown at Exhibit C2, Tab 4, Schedule 1, page 12, Table 8 compared to the proposed "20-Year Trend" method for 2007.

Since the Company cannot influence the commodity portion of the total bill, the percent of delivery charge impact (Item 1.3) provides a better representation of the true rate impact on residential customers that is controllable by the Company than the total bill impact (Item 1.2). This is also consistent with the Board's Minimum Filing Requirements in a manner to try to isolate the delivery related sufficiency/deficiency separate and apart from the commodity related sufficiency/deficiency. As each transportation-service customer can incur different commodity rate charged by his or her broker or supplier, the Company's gas supply charge is used as a proxy for these customers. The bill is calculated based upon July 2006 rates under EB-2006-0099.

Witnesses: I. Chan
J. Collier
K. Culbert
J. Denomy
T. Ladanyi

All the impacts reported here include the corresponding forecast degree days for the Central, Eastern, and Niagara regions based upon the degree days forecasting methodology under review.

Table 1
Comparison of Eight Different Degree Days Forecast Methodologies

Item		Col. 1 Energy Probe	Col. 2 de Bever	Col. 3 de Bever with Trend	Col. 4 10-Yr MA	Col. 5 20-Yr MA	Col. 6 30-Yr MA	Col. 7 Avg(20-Yr, 30-Yr MA)	Col. 8 Naïve
1.1	Total operating costs incurred by EGDI in utilizing the method ('$000)	There are no material or significant operating costs incurred by using each of the degree day forecasting methods.							
1.2	Total Bill Impact on a Typical Residential Customer (%)	1.5%	3.2%	0.2%	1.4%	3.3%	5.3%	2.6%	1.9%
1.3	Delivery Bill Impact on a Typical Residential Customer (%)	0.3%	0.6%	0.0%	0.3%	0.6%	0.9%	0.5%	0.3%
1.4	Impact on Revenue Requirement (%)	0.4%	0.7%	0.0%	0.3%	0.7%	1.1%	0.5%	0.4%
1.5	Impact on Revenue Deficiency ($M)	12.3	21.2	1.6	9.7	22.1	35.0	17.6	12.6
1.6	Volumetric Impact vs 20-Yr ($10^6 m^3$)	192.1	331.7	25.0	151.8	345.6	548.2	275.0	196.5

Witnesses: I. Chan
J. Collier
K. Culbert
J. Denomy
T. Ladanyi

ENERGY PROBE INTERROGATORY #8

INTERROGATORY

Ref: C2/T4/S1, para. 27

Issue Number: 2.3
Issue: Is the forecast of degree days appropriate?

a) Please provide Tables 5, 6, 7 and 8 for the Eastern region.
b) Please provide Tables 5, 6, 7 and 8 for the Niagara region.

RESPONSE

a) Please see tables below for the Eastern region.

Table 5 Eastern
Actual and forecast Eastern degree days ('out-of-sample'), 1990 to 2005

Col. 1	*Col. 2*	*Col. 3*	*Col. 4*	*Col. 5*	*Col. 6*	*Col. 7*	*Col. 8*	*Col. 9*	*Col. 10*	*Col. 11*
Fiscal Year	Actual	Naïve	10-yr MA	20-yr MA	30-yr MA	50/50	de Bever	de Bever with Trend	Energy Probe	20-yr Trend
1990	4,663	4,564	4,579	4,671	4,691	4,581	4,618	4,479	4,466	4,471
1991	4,258	4,647	4,570	4,667	4,684	4,578	4,642	4,538	4,521	4,472
1992	4,827	4,663	4,584	4,654	4,688	4,597	4,628	4,577	4,606	4,505
1993	4,730	4,258	4,534	4,625	4,675	4,560	4,544	4,479	4,474	4,446
1994	4,971	4,827	4,536	4,625	4,683	4,599	4,637	4,547	4,576	4,515
1995	4,293	4,730	4,579	4,630	4,673	4,606	4,662	4,589	4,622	4,539
1996	4,779	4,971	4,604	4,643	4,687	4,655	4,723	4,635	4,730	4,623
1997	4,665	4,293	4,586	4,633	4,669	4,598	4,659	4,551	4,569	4,528
1998	4,101	4,779	4,606	4,636	4,671	4,621	4,686	4,562	4,503	4,571
1999	4,089	4,665	4,640	4,627	4,666	4,634	4,666	4,604	4,572	4,602
2000	4,301	4,101	4,593	4,586	4,645	4,587	4,560	4,509	4,358	4,529
2001	4,500	4,089	4,537	4,554	4,624	4,533	4,469	4,518	4,437	4,442
2002	4,025	4,301	4,501	4,543	4,603	4,494	4,417	4,450	4,341	4,384
2003	4,821	4,500	4,525	4,530	4,592	4,497	4,456	4,444	4,539	4,403
2004	4,579	4,025	4,445	4,491	4,565	4,448	4,290	4,328	4,565	4,331
2005	4,491	4,821	4,454	4,516	4,571	4,474	4,488	4,404	4,722	4,377

Witness: J. Denomy

Table 6 Eastern
Out-of-sample forecast performance, all available years (1990 to 2005)

Col. 1	*Col. 2*	*C3*	*Col. 4*	*C5*	*Col. 6*	*C7*	*Col. 8*	*C9*	*Col. 10*	*C11*	*Col. 12*	*Col. 13*
	Accuracy				Symmetry				Stability			
	MAPE		RMSPE		MPE		Percent Overforecast		Standard Deviation		Score	Overall Rank
Naïve	7.9%	9	8.9%	9	0.6%	2	44%	1	298	9	30	***8***
10-yr MA	5.9%	6	7.1%	5	1.5%	5	44%	1	54	2	19	***3***
20-yr MA	5.6%	2	7.2%	6	2.6%	8	56%	1	57	3	20	***5***
20-yr Trend	**6.2%**	**8**	**6.9%**	**3**	**0.1%**	**1**	**38%**	**7**	**83**	**6**	**25**	***6***
30-yr MA	5.7%	3	7.6%	8	3.6%	9	63%	7	44	1	28	***7***
50/50	5.7%	4	7.0%	4	1.8%	6	44%	1	60	4	19	***3***
de Bever	5.8%	5	7.4%	7	1.9%	7	38%	7	119	8	34	***9***
de Bever with Trend	6.0%	7	6.9%	2	0.6%	3	44%	1	80	5	18	***2***
Energy Probe	**5.2%**	**1**	**6.1%**	**1**	**1.1%**	**4**	**44%**	**1**	**109**	**7**	**14**	***1***

Table 7 Eastern
Out-of-sample forecast performance, recent ten year period (1996 to 2005)

Col. 1	*Col. 2*	*C3*	*Col. 4*	*C5*	*Col. 6*	*C7*	*Col. 8*	*C9*	*Col. 10*	*C11*	*Col. 12*	*Col. 13*
	Accuracy				Symmetry				Stability			
	MAPE		RMSPE		MPE		Percent Overforecast		Standard Deviation		Score	Overall Rank
Naïve	8.9%	9	9.7%	9	0.8%	1	50%	1	341	9	29	***7***
10-yr MA	6.0%	6	7.6%	5	3.0%	6	50%	1	67	3	21	***4***
20-yr MA	5.9%	3	7.8%	6	3.6%	8	60%	6	56	2	25	***6***
20-yr Trend	**6.2%**	**8**	**7.3%**	**2**	**1.4%**	**2**	**40%**	**6**	**104**	**6**	**24**	***5***
30-yr MA	6.2%	7	8.4%	8	4.8%	9	70%	9	45	1	34	***9***
50/50	5.9%	2	7.6%	4	3.1%	7	50%	1	74	4	18	***3***
de Bever	6.0%	4	8.0%	7	2.8%	5	40%	6	141	8	30	***8***
de Bever with Trend	6.0%	5	7.3%	3	1.9%	3	50%	1	94	5	17	***2***
Energy Probe	**4.7%**	**1**	**6.1%**	**1**	**2.5%**	**4**	**50%**	**1**	**132**	**7**	**14**	***1***

Table 8 Eastern
Out-of-sample forecast performance, recent five year period (2001 to 2005)

Col. 1	*Col. 2*	*C3*	*Col. 4*	*C5*	*Col. 6*	*C7*	*Col. 8*	*C9*	*Col. 10*	*C11*	*Col. 12*	*Col. 13*
	Accuracy				Symmetry				Stability			
	MAPE		RMSPE		MPE		Percent Overforecast		Standard Deviation		Score	Overall Rank
Naïve	8.4%	9	8.7%	9	2.7%	8	40%	1	324	9	36	***9***
10-yr MA	4.5%	3	6.1%	2	0.6%	2	40%	1	41	5	13	***2***
20-yr MA	4.5%	4	6.4%	7	1.3%	6	60%	1	25	2	20	***4***
20-yr Trend	**5.4%**	**8**	**6.2%**	**4**	**1.8%**	**7**	**20%**	**8**	**40**	**4**	**31**	***8***
30-yr MA	4.8%	5	6.9%	8	2.8%	9	60%	1	24	1	24	***6***
50/50	4.5%	2	6.1%	3	0.5%	1	40%	1	31	3	10	***1***
de Bever	4.9%	6	6.2%	5	1.0%	4	20%	8	79	7	30	***7***
de Bever with Trend	5.2%	7	6.4%	6	0.8%	3	40%	1	70	6	23	***5***
Energy Probe	**4.1%**	**1**	**5.0%**	**1**	**1.1%**	**5**	**40%**	**1**	**143**	**8**	**16**	***3***

b) Please see tables below for the Niagara region.

Table 5 Niagara

Actual and forecast Niagara degree days ('out-of-sample'), 1990 to 2005

Col. 1	*Col. 2*	*Col. 3*	*Col. 4*	*Col. 5*	*Col. 6*	*Col. 7*	*Col. 8*	*Col. 9*	*Col. 10*	*Col. 11*
Fiscal Year	Actual	Naïve	10-yr MA	20-yr MA	30-yr MA	50/50	de Bever	de Bever with Trend	Energy Probe	20-yr Trend
1990	3,603	3,649	3,690	3,708	3,707	3,689	3,643	3,712	3,745	3,670
1991	3,288	3,663	3,670	3,708	3,703	3,677	3,651	3,700	3,840	3,652
1992	3,676	3,603	3,664	3,699	3,700	3,670	3,651	3,684	3,794	3,640
1993	3,840	3,288	3,609	3,680	3,687	3,617	3,609	3,545	3,569	3,548
1994	4,000	3,676	3,577	3,679	3,689	3,620	3,641	3,573	3,587	3,550
1995	3,472	3,840	3,623	3,692	3,689	3,630	3,686	3,647	3,702	3,571
1996	3,930	4,000	3,635	3,708	3,706	3,670	3,709	3,722	3,883	3,634
1997	3,615	3,472	3,630	3,701	3,697	3,634	3,693	3,674	3,736	3,572
1998	3,174	3,930	3,659	3,722	3,704	3,649	3,709	3,695	3,698	3,594
1999	3,270	3,615	3,673	3,702	3,699	3,655	3,703	3,690	3,624	3,612
2000	3,377	3,174	3,626	3,658	3,680	3,613	3,698	3,643	3,503	3,545
2001	3,595	3,270	3,587	3,628	3,668	3,578	3,714	3,633	3,552	3,487
2002	3,122	3,377	3,564	3,614	3,654	3,546	3,663	3,576	3,505	3,438
2003	3,917	3,595	3,595	3,602	3,652	3,558	3,642	3,572	3,730	3,463
2004	3,605	3,122	3,539	3,558	3,632	3,523	3,510	3,454	3,709	3,414
2005	3,618	3,917	3,547	3,585	3,644	3,555	3,625	3,518	3,810	3,466

Table 6 Niagara

Out-of-sample forecast performance, all available years (1990 to 2005)

Col. 1	*Col. 2*	*C3*	*Col. 4*	*C5*	*Col. 6*	*C7*	*Col. 8*	*C9*	*Col. 10*	*C11*	*Col. 12*	*Col. 13*
	Accuracy				Symmetry				Stability			
	MAPE		RMSPE		MPE		Percent Overforecast		Standard Deviation		Score	Overall Rank
Naïve	8.8%	9	10.4%	9	0.7%	2	50%	1	272	9	30	***6***
10-yr MA	6.5%	2	8.2%	3	2.0%	4	50%	1	47	2	12	***1***
20-yr MA	6.8%	5	8.6%	5	3.3%	7	63%	5	51	3	25	***4***
20-yr Trend	**6.7%**	**3**	**7.8%**	**1**	**0.1%**	**1**	**44%**	**4**	**80**	**7**	**16**	***3***
30-yr MA	6.8%	4	8.6%	6	3.7%	8	75%	9	24	1	28	***5***
50/50	6.4%	1	8.0%	2	1.9%	3	50%	1	52	5	12	***1***
de Bever	7.0%	7	8.8%	8	3.1%	6	63%	5	52	4	30	***6***
de Bever with Trend	7.2%	8	8.7%	7	2.2%	5	63%	5	79	6	31	***8***
Energy Probe	**6.9%**	**6**	**8.4%**	**4**	**3.8%**	**9**	**69%**	**8**	**118**	**8**	**35**	***9***

Table 7 Niagara
Out-of-sample forecast performance, recent ten year period (1996 to 2005)

Col. 1	*Col. 2*	*C3*	*Col. 4*	*C5*	*Col. 6*	*C7*	*Col. 8*	*C9*	*Col. 10*	*C11*	*Col. 12*	*Col. 13*
	Accuracy				Symmetry				Stability			
	MAPE		RMSPE		MPE		Percent Overforecast		Standard Deviation		Score	Overall Rank
Naïve	9.3%	9	10.9%	9	1.2%	2	50%	1	321	9	30	***7***
10-yr MA	6.9%	3	8.8%	4	3.0%	4	50%	1	46	2	14	***2***
20-yr MA	7.4%	5	9.5%	6	4.2%	6	60%	4	58	4	25	***4***
20-yr Trend	**7.2%**	**4**	**8.1%**	**2**	**0.6%**	**1**	**40%**	**4**	**78**	**6**	**17**	***3***
30-yr MA	7.4%	6	9.5%	7	4.9%	9	80%	9	27	1	32	***8***
50/50	6.8%	2	8.6%	3	2.8%	3	50%	1	53	3	12	***1***
de Bever	7.8%	8	9.8%	8	4.7%	7	70%	7	63	5	35	***9***
de Bever with Trend	7.5%	7	9.2%	5	3.3%	5	60%	4	86	7	28	***6***
Energy Probe	**6.2%**	**1**	**7.9%**	**1**	**4.8%**	**8**	**70%**	**7**	**128**	**8**	**25**	***4***

Table 8 Niagara
Out-of-sample forecast performance, recent five year period (2001 to 2005)

Col. 1	*Col. 2*	*C3*	*Col. 4*	*C5*	*Col. 6*	*C7*	*Col. 8*	*C9*	*Col. 10*	*C11*	*Col. 12*	*Col. 13*
	Accuracy				Symmetry				Stability			
	MAPE		RMSPE		MPE		Percent Overforecast		Standard Deviation		Score	Overall Rank
Naïve	9.4%	9	9.6%	9	2.8%	8	40%	1	310	9	36	***9***
10-yr MA	5.3%	1	7.4%	2	0.4%	3	20%	6	24	3	15	***1***
20-yr MA	5.4%	3	8.0%	6	1.3%	4	40%	1	27	4	18	***3***
20-yr Trend	**6.8%**	**8**	**7.6%**	**4**	**2.8%**	**7**	**20%**	**6**	**28**	**5**	**30**	***8***
30-yr MA	5.5%	5	8.3%	7	2.7%	6	80%	6	13	1	25	***6***
50/50	5.5%	4	7.4%	3	0.0%	1	20%	6	20	2	16	***2***
de Bever	6.1%	6	8.6%	8	2.2%	5	60%	1	75	7	27	***7***
de Bever with Trend	6.3%	7	7.9%	5	0.0%	2	40%	1	68	6	21	***4***
Energy Probe	**5.3%**	**2**	**6.5%**	**1**	**2.9%**	**9**	**60%**	**1**	**128**	**8**	**21**	***4***

ENERGY PROBE INTERROGATORY #9

INTERROGATORY

Ref: C2/T4/S1, Table 9

Issue Number: 2.3
Issue: Is the forecast of degree days appropriate?

a) Please provide a table similar to Table 9 for the Eastern region Environment Canada degree day forecasts.
b) Please provide a table similar to Table 9 for the Niagara region Environment Canada degree day forecasts.

RESPONSE

a) Please see Table 1 below.

Table 1

Eastern region Environment Canada degree day forecasts, 2007-8

Col. 1	*Col. 2*	*Col. 3*
Forecast Method	2007	2008
Naïve	4,491	4,491
10-yr MA	4,435	4,435
20-yr MA	4,510	4,510
30-yr MA	4,567	4,567
50% 20-yr Trend / 50% 30-yr MA	4,487	4,483
de Bever	4,558	4,558
de Bever with Trend	4,370	4,357
Energy Probe	4,459	4,445
20-Year Trend	**4,408**	**4,399**

b) Please see Table 2 below.

Table 2

Niagara region Environment Canada degree day forecasts, 2007-8

Col. 1	*Col. 2*	*Col. 3*
Forecast Method	2007	2008
Naïve	3,618	3,618
10-yr MA	3,522	3,522
20-yr MA	3,576	3,576
30-yr MA	3,641	3,641
50% 20-yr Trend / 50% 30-yr MA	3,577	3,575
de Bever	3,643	3,643
de Bever with Trend	3,511	3,504
Energy Probe	3,597	3,589
20-Year Trend	**3,513**	**3,508**

ENERGY PROBE INTERROGATORY #11

INTERROGATORY

Ref: C2/T4/S1, para. 39

Issue Number: 2.3
Issue: Is the change in forecasting methodology for degree days from the "de Bever" to the "20-Year Trend" justified?

Please provide a description of what each of the following statistics mean:

a) the Adjusted R-squared figure of 0.08591;
b) the Prob. figure of 0.1124 in column 5 on the TREND line;
c) the F-statistic value of 2.785709; and
d) what is the significant of a negative value for an adjusted R-squared figure?

RESPONSE

The following response assumes that a constant coefficient is included in all regression models discussed.

a) R-squared measures the percentage of the total variation in the dependent variable, in this case heating degree days, explained by a regression model. The formula for calculating R-squared is a nondecreasing function of the number of independent variables in a regression model. In other words, R-squared will increase or at least never decrease as more independent variables are added to the regression model.

   Adjusted R-squared takes this property of R-squared into account and adjusts R-squared for the number of independent variables, in other words the degrees of freedom, in a regression model. Consequently, if the number of estimated coefficients in a regression model is greater than 1, adjusted R-squared will be less than R-squared.

   Adjusted R-squared therefore explains the percentage of variation in the dependent variable explained by the regression model after adjusting for the number of independent variables in the regression model. Since adjusted R-squared takes into account degrees of freedom it is possible to have a negative adjusted R-squared statistic.

Witness: J. Denomy

b) The Prob. figure is known as the p-value or probability value of a coefficient. The p-value is the observed or exact level of significance for a coefficient. It is defined as the lowest significance level at which a null hypothesis can be rejected. If the p-value is less than a chosen level of significance, the null hypothesis is rejected in favour of the alternative hypothesis.

c) The F-statistic is used to test whether or not all of the independent variables in a regression model jointly explain variation in the dependent variable. In the case of a simple linear regression (that is a regression with only one independent variable) the results of an F-test will be the same as the result of a t-test under the null hypothesis that the coefficient of the independent variable is zero.

d) Please see response to part a).

It should be noted that while high R-squared values, high t-statistics (low p-values) and high F-statistics (low p-values) are desirable, these tests are in no way indicative of the forecasting ability of a model. Consider the following example.

The table below shows two of the models used to generate the forecast of Fiscal 2006 Degree Days for the Central weather zone presented in the response to Energy Probe Interrogatory #6 at Exhibit I, Tab 5, Schedule 6. The first model is the 20-Year Trend model, the second model is the Energy Probe model.

Table 1

20-Year Trend Model

Dependent Variable: ECCEN
Sample: 1985 2004
Included observations: 20

Col. 1	***Col. 2***	***Col. 3***	***Col. 4***	***Col. 5***
Variable	**Coefficient**	**Std. Error**	**t-Statistic**	**Prob.**
C	4780.95	552.24	8.66	0.0000
TIME	-17.19	10.46	-1.64	0.1176

R-squared	0.1305	F-statistic	2.7013
Adjusted R-squared	0.0822	Prob(F-statistic)	0.1176
Durbin-Watson stat	1.8681		

Table 2

Energy Probe Model

Dependent Variable: ECCEN
Sample: 1964 2004
Included observations: 41

Col. 1	***Col. 2***	***Col. 3***	***Col. 4***	***Col. 5***
Variable	**Coefficient**	**Std. Error**	**t-Statistic**	**Prob.**
C	4715.59	1145.28	4.12	0.0002
TIME	-13.64	4.15	-3.29	0.0022
WACDD	1.60	0.85	1.89	0.0669
ACDD	-1.62	0.89	-1.82	0.0762

R-squared	0.4633	F-statistic	10.6475
Adjusted R-squared	0.4198	Prob(F-statistic)	0.0000
Durbin-Watson stat	1.8945		

From the tables presented above it is apparent that the Energy Probe Model has higher R-squared statistics, higher t-statistics and a higher F-statistic than the 20-Year Trendmodel. However, the 20-Year trend model is a far better predictor of degree days. Actual Degree Days for Fiscal 2006 were 3,481. The Energy Probe model predicts Fiscal 2006 Degree Days to be 3,857 which translates into a percentage variance of 10.80%. The 20-Year Trend model predicts Fiscal 2006 Degree Days to be 3,681 which translates into a percentage variance of 5.75%.

ENERGY PROBE INTERROGATORY #12

INTERROGATORY

Ref: C2/T4/S1, Tables 13-15

Issue Number: 2.3
Issue: Is the forecast of degree days appropriate?

a) Does the Company agree with the following statement: 'When using regression analysis in forecasting applications it is generally acceptable to exclude variables with coefficients that have t-statistics less than one in absolute value.' If not, why not?
b) The TREND values in the equations found in Figures A1 and A2 have t-statistics that are less than 1.0. Please explain why the Company has left the TREND variable in the equations.
c) Please re-estimate both equations (Eastern and Niagara) excluding the TREND variable.
d) What is the forecast of Environment Canada degree days for the Eastern and Niagara regions for 2007 and 2008 using these re-estimated equations?
e) What is the forecast of gas supply degree days for the Eastern and Niagara regions for 2007 and 2008 based on the forecasts in part (d) above?

RESPONSE

Based on the questions in this interrogatory the responses below assumes Energy Probe is referring to Figures A2 and A3.

a) The Company agrees with the statement that it is generally *acceptable* to exclude variables with coefficients that have t-statistics less than one in absolute value.

b) The Company has left the TREND variable in the equations in order to produce forecasts of degree days using the 20-Year Trend method. Like the application of the de Bever method the Company intends to utilize whichever degree day forecasting methodology that is adopted for the Central weather zone for the Eastern and Niagara weather zones.

c) If the TREND variable is excluded from the equations the 20-Year Trend method defaults to the 20 Year Moving Average Method. Forecasts of Environment Canada

Witness: J. Denomy

degree days for the Eastern and Niagara regions based on the 20 Year Moving Average method can be found in the response to Energy Probe Interrogatory #9 at Exhibit I, Tab 5, Schedule 9.

d) Please see response to c).

e) Please see table below for the Eastern and Niagara region gas supply degree day forecasts based on the 20 Year Moving Average method.

Table 1

Gas Supply Degree Days

Col. 1	*Col. 2*	*Col. 3*
	Gas Supply	
Fiscal Year	Eastern	Niagara
2007	4,465	3,545
2008	4,465	3,545

Witness: J. Denomy

17. In summary, the de Bever with Trend method consistently provides the most accurate and symmetrical results, and despite having less stability than other methods, still ranks the best overall. Therefore the Company is proposing to use the de Bever with Trend methodology for determining future degree days.

18. Table 5 provides the Central Zone Environment Canada degree day forecast for Fiscal Years 2005 to 2007 considering each of the various tested methodologies. The de Bever with Trend methodology produces a forecast of 3,715 degree days for Fiscal 2006.

TABLE 5 CENTRAL EC DEGREE DAY FORECAST COMPARISON

Forecast Method	FY 2005	FY 2006	FY 2007
DeBever	3,806	3,842	3,842
de Bever with Trend	**3,712**	**3,715**	**3,700**
50% 20-yr Trend / 50% 30-yr MA	3,831	3,841	3,831
10-yr MA	3,814	3,760	3,763
20-yr MA	3,908	3,879	3,876
30-yr MA	4,014	4,000	3,998
Naïve	4,102	3,785	3,785
EGD Forecast*	**3,743**	**3,722**	**3,706**

* The Company proposes to drop the 5-year weighted average variable if it is found to be not significant in the formulation of the de Bever with Trend methodology.

19. As noted in Table 5 above, the Company is proposing that should the 5-year weighted average variable be found to be not significant in the formulation of the de Bever with Trend forecast, that that variable not be included in the final estimate. For the Fiscal 2006 forecast, the 5-year weighted average variable was found to be not statistically significant (T-Statistic 0.47), and was therefore dropped from the equation. The Company will incorporate this variable in future specifications when it is found to be statistically significant. The Company believes that the 5-year weighted-average term is extremely important in capturing short-term weather trends, as it was originally intended to do, and that the model is only improved with the use of a trend variable.

20. The estimated de Bever with Trend equation, the adjusted R-squared, the Durbin-Watson statistic, and the F-statistic for the Fiscal 2006 forecast are as follows:

- Heating Degree days = 4574.287 - 15.784 Trend
  (t-statistics) (44.37) (-5.22)

  R^2Ad = 0.41
  DW = 1.87
  F-Stat = 27.28
  Sample = 1964 to 2004

21. Tables 6 to 8 below present actual degree day history by weather zone along with the de Bever with Trend model's fitted values by fiscal year. Figures 4 to 6 that follow the tables present this information graphically.

ENERGY PROBE INTERROGATORY #27

INTERROGATORY

Reference: Ex. A2, Tab 2, Sch. 5, Page 13 & 15 & 16

a) Please provide the same regression statistics as provided for the equation found on page 13 for the equations found in Note 2 on both page 15 and 16.

b) Please provide the same regression statistics as provided for the equation on page 13 for the equations found in Note 2 on both page 15 and 16, where both equations have been modified to included the five year weighted average as an explanatory variable.

RESPONSE

a) The regression statistics for the Eastern and Niagara de Bever with Trend models, excluding the 5-year weighted average variable, are provided below (note that the trend variable begins in 1953).

Eastern Region:

- Heating Degree days = 4957.528 – 10.407(Trend)
  (t-statistics) (49.48) (-3.58)

  R^2Ad = 0.23
  DW = 2.10
  F-Stat = 12.83
  Sample = 1965 to 2004

Niagara Region:

- Heating Degree days = 3943.985 - 8.376(Trend)
  (t-statistics) (34.42) (-2.58)

  R^2Ad = 0.13
  DW = 2.00
  F-Stat = 6.64
  Sample = 1967 to 2004

b) The regression statistics for the Eastern and Niagara de Bever with Trend models, including the 5-year weighted average variable are provided below (note that the trend variable begins in 1953).

Eastern Region:

- Heating Degree days = 6105.53 – 12.719(Trend) - 0.231(5-yr WA)
  (t-statistics) (3.64) (-2.85) (-0.69)

  R^2Ad = 0.22
  DW = 2.15
  F-Stat = 6.56
  Sample = 1965 to 2004

Niagara Region:

- Heating Degree days = 5128.171 – 10.917(Trend) - 0.299(5-yr WA)
  (t-statistics) (3.80) (-2.51) (-0.88)

  R^2Ad = 0.13
  DW = 2.06
  F-Stat = 3.69
  Sample = 1967 to 2004

Appendix

39. The equation and test statistics that correspond to the Fiscal 2007 forecast for the 20-Year Trend method are presented in Figures A1 to A3.[7]

Figure A1
20-Year Trend forecasting equation and test statistics, Central

Dependent Variable: ECCEN   Method: Least Squares
Sample: 1986 2005   Included observations: 20

Col. 1	*Col. 2*	*Col. 3*	*Col. 4*	*Col. 5*
Variable	**Coefficient**	**Std. Error**	**t-Statistic**	**Prob.**
C	4802.0	562.1	8.543	0
TREND	-17.434	10.446	-1.669	0.1124

Adjusted R-squared	0.08591	F-statistic	2.785709
Durbin-Watson stat	1.86762		

[7] The mnemonics in Figures A1 through A6 are as follows:

CEN	Central region
EAS	Eastern region
NIA	Niagara region
TREND	Trend (1943=1 for Central, 1941=1 for Eastern and Niagara)
EC*XXX*	Environment Canada degree days, where *XXX* is CEN, EAS or NIA
WA*XXX*	Five-year weighted average of degree days, where *XXX* is CEN, EAS or NIA
AVG*XXX*	Five-year average of degree days, where *XXX* is CEN, EAS or NIA

Figure A2

20-Year Trend forecasting equation and test statistics, Eastern

Dependent Variable: ECEAS
Sample: 1986 2005

Method: Least Squares
Included observations: 20

Col. 1	*Col. 2*	*Col. 3*	*Col. 4*	*Col. 5*
Variable	**Coefficient**	**Std. Error**	**t-Statistic**	**Prob.**
C	5004.7	586.7	8.531	0
TREND	-8.904	10.514	-0.847	0.4082

Adjusted R-squared	-0.015105	F-statistic	0.717279
Durbin-Watson stat	2.051416		

Figure A3

20-Year Trend forecasting equation and test statistics, Niagara

Dependent Variable: ECNIA
Sample: 1986 2005

Method: Least Squares
Included observations: 20

Col. 1	*Col. 2*	*Col. 3*	*Col. 4*	*Col. 5*
Variable	**Coefficient**	**Std. Error**	**t-Statistic**	**Prob.**
C	3879.6	537.2	7.222	0
TREND	-5.469	9.627	-0.568	0.577

Adjusted R-squared	-0.036963	F-statistic	0.322728
Durbin-Watson stat	1.958124		

40. Figures A4 through A6 are analogous to Figures A1 through A3, but correspond to the Energy Probe method. Note the cycle lengths of 41, 40 and 40 for the Central, Eastern and Niagara weather zones respectively, as indicated by the number of included observations.

Figure A4
Energy Probe forecasting equation and test statistics, Central

Dependent Variable: ECCEN Method: Least Squares
Sample: 1965 2005 Included observations: 41

Col. 1	*Col. 2*	*Col. 3*	*Col. 4*	*Col. 5*
Variable	**Coefficient**	**Std. Error**	**t-Statistic**	**Prob.**
C	5403.2	1190.7	4.538	0.0001
TREND	-17.171	4.427	-3.878	0.0004
WACEN	1.363	0.776	1.757	0.0871
AVGCEN	-1.509	0.794	-1.900	0.0652

Adjusted R-squared 0.469415 F-statistic 12.79616
Durbin-Watson stat 1.942138

Figure A5
Energy Probe forecasting equation and test statistics, Eastern

Dependent Variable: ECEAS Method: Least Squares
Sample: 1966 2005 Included observations: 40

Col. 1	*Col. 2*	*Col. 3*	*Col. 4*	*Col. 5*
Variable	**Coefficient**	**Std. Error**	**t-Statistic**	**Prob.**
C	7959.7	1693.7	4.700	0
TREND	-14.701	4.241	-3.466	0.0014
WAEAS	1.912	0.801	2.388	0.0223
AVGEAS	-2.489	0.857	-2.903	0.0063

Adjusted R-squared 0.338958 F-statistic 7.665912
Durbin-Watson stat 2.301955

Figure A6
Energy Probe forecasting equation and test statistics, Niagara

Dependent Variable: ECNIA	Method: Least Squares
Sample: 1966 2005	Included observations: 40

Col. 1	*Col. 2*	*Col. 3*	*Col. 4*	*Col. 5*
Variable	**Coefficient**	**Std. Error**	**t-Statistic**	**Prob.**
C	5760.0	1216.5	4.735	0
TREND	-8.040	3.208	-2.506	0.0169
WANIA	1.916	0.757	2.532	0.0159
AVGNIA	-2.389	0.824	-2.901	0.0063

Adjusted R-squared	0.216996	F-statistic	4.602723
Durbin-Watson stat	2.055237		

RP-2003-0063
EB-2003-0087
EB-2003-0097

IN THE MATTER OF.the *Ontario Energy Board Act, 1998*, S.O.1998, c.15, Schedule B;

AND IN THE MATTER OF an Application by Union Gas Limited for an Order or Orders approving or fixing just and reasonable rates and other charges for the sale, distribution, storage, and transmission of gas for the period commencing January 1, 2004.

BEFORE: Paul B. Sommerville
Presiding Member

Art Birchenough
Member

DECISION WITH REASONS

March 18, 2004

The Board notes the concerns expressed about the inherent complexity of programs of this kind, but is not convinced Union's proposed changes add materially to the program's complexity. The changes proposed by RMI and accepted by Union are unlikely to diminish the capacity of the current program and offer the opportunity for marginal improvements. To the extent that intervenors have significant concerns about the operation of Union's risk management program, it is open to them in future proceedings to bring expert evidence recommending appropriate changes to the program.

The Board notes that LPMA and VECC supported the risk management program, but argued that there was a need for increased reporting requirements. This position was characterized by Union as leading to unnecessary and inappropriate micro-management. The Board believes that Union's commitment to file an updated risk management policy, and at the time of deferral account disposition to provide all relevant data for an assessment of the cost impacts and compliance with the policy is sufficient to deal with these concerns.

The Board finds that Union's risk management program does provide value to ratepayers and is, therefore, appropriate, and that the specific changes Union is proposing to implement in the 2004 rate year are reasonable and provide an opportunity to enhance the value of the program.

2.2 WEATHER NORMALIZATION

Union's Request

Union proposes to change its weather normalization methodology and to recover the cost consequences in its rates. This proposal was supported by written evidence produced for Union by Weather Bank Inc (WB) and by Dr. Andrew Weaver, a professor of climatology at the University of Victoria.

Background

Normal weather is defined in terms of heating degree days ("HDD"), calculated on the variances in daily temperatures below 18° C. For example, if the mean daily temperature is 11°C, there are 18 - 11 = 7 HDDs on that day. If the mean daily temperature is 18° C or higher, there are no HDDs.

Weather normalization is used in forecasting demand for the general service classes (M2, R1 and R10), storage and transportation allocations, gas supply planning, and rate design. Weather normalization is also used to estimate average use per customer, which, when multiplied by the forecast number of customers, yields a demand forecast. Although weather normalization is not used directly to forecast demand for other classes, it can have impacts on other rate classes by affecting load balancing costs.

Union has historically used a 30-year rolling average method. In the RP-2002-0130 proceeding respecting 2003 rates, Union proposed to introduce a twenty-year trend methodology similar to what it was already using for distribution system planning and its gas supply portfolio. The impact of extending its use to ratemaking would have been to increase the revenue requirement to be captured in 2003 rates by an extra $13.7 million. At the time, Union was under a three-year trial PBR plan and sought to make this change as a non-routine adjustment. The PBR plan had been established on the basis of the existing weather normalization methodology. The Board denied Union's application on the basis that the weather risk was to be managed by Union as part of its PBR plan, and it was not appropriate to effect a change of this magnitude in the course of the PBR period.

Union's Position

Union's evidence states that, based on data from 1985 to 2000, the 30-year average weather normalization methodology consistently overestimates the heating demand by customers by about 7.6%. Mr. Fogwill of Union testified that the impact of a 1% variance in HDDs is about $3.0 million in annual delivery revenues.

Union argued that the 30-year average method assumed a static long run climatic condition and that this assumption was invalid. It noted that over the last 17 years, the method over-forecast HDDs fourteen times, and under-forecast HDDs only three times. Union cited Dr. Weaver's evidence in respect of climate change and global warming in support of its contention that variations were no longer symmetrical around the weather normal estimate.

In addition, Union stated that "... the yearly variability in temperature is increasing, with the standard deviation of 166 HDDs over the period 1956-1985 period increasing to 310 HDDs over the period 1972-2001. Union stated that its consultant, WB, agreed with Dr. Weaver that global warming was occurring. WB also supported Union's claim that volatility was increasing, noting an increase in the frequency of weather events such as El Nino and La Nina.

Dr. Weaver stated that there was an increase in global average temperature of approximately 0.6 degrees Centigrade (+/- 2°) over the twentieth century. He stated the warming trend occurred during two periods, 1901-1945 and 1976-2000 and were separated by a cooling period between 1945-1976. Union stated that 0.6 degrees per century corresponded to 1.6 HDDs per year. Dr. Weaver gave an estimate of a global average temperature increase of 2°C, but qualified this figure as it applies to Ontario, due to the amplification effect of Ontario geography.

Mr. Root of WB testified that in his experience extreme weather events had become much more common over the last 20 years. He suggested that use of the 20-year trend method would have the effect of mitigating the volatility associated with such extreme weather.

Union listed five objectives that its proposed normalization method was assessed against:

1. symmetry – actual HDDs are expected to vary positively and negatively equally with respect to the forecast HDDs;

2. accuracy – over time the variance between actual and normal HDDs should be minimized;

3. stability – the year over year normalized HDD estimate should not vary significantly when measured using standard deviation;

4. sustainability – the method should not require significant amendments in the near future; and

5. simplicity – the method should be easy to use.

The 20 year trend methodology uses data from twelve Environment Canada weather stations in Union's franchise area. The data is weighted by the throughput volumes in the region associated with each weather station. Union then applied ordinary least squares regression analysis to find the best fit to the weighted HDD.

Union ranked seven weather normalization methods by weighting and applying the above five objectives. The weightings applied by Union were on a scale from 1 to 3 as follows:

1. symmetry was given a weight of 3,
2. accuracy was given a weight of 2, and
3. stability, sustainability, and simplicity were given a weight of 1.

Based on these measures, Union ranked the methods in order, from best to worst, as follows: 20-year trend with forecast information, 20-year trend, 30-year trend, 38-year trend, 20-year average, 10-year average, and 30-year average. Union proposed the 20-year trend method rather than the 20-year trend with forecast information method, arguing that the latter was far more complex and that it relied upon a third party's proprietary model and therefore might not be sustainable.

Union stated that the rate impact of adopting the new method would be an increase of $20.4 million in the revenue requirement which would be allocated to the M2, R01, and R10 general service classes only. These impacts resulted from an approximately 3.9% deviation between the 30-year weather average and the proposed 20-year trend weather normalization methodologies. Union proposed to allocate the revenue impacts only to the general service classes because these are the only classes for which Union forecasts demand using weather normalization.

Union's witness testified that other than EGDI, whose weather normalization methodology includes a trending component and a moving average component, no other Canadian utility uses a trend method for this purpose. Further, Union was unable to cite any U.S. gas utility that uses a 20-year trend method.

Union noted that Environment Canada, the U.S. Weather Service, and the World Meteorological Organization all used a 30-year average weather normalization methodology. Dr. Weaver was unaware of any national or international meteorological organization that has changed from a 30-year average to a 20-year trend method, but he pointed out that those groups use the methodology to define a reference value and not as an indicator of the rate at which the reference is changing.

Although Union agreed that the data in evidence showed increasing variability over time, i.e., the data may exhibit heteroscedasticity, Union stated that it had not statistically tested for heteroscedasticity. Union also stated that the data it was relying on was time series data whose mean and variance were changing over time. The data were non-stationary and the validity of standard statistical tests was in question if the data were not stationary.

Board Findings

The Board is asked to approve a change in the weather normalization methodology that is applied to M2, R1 and R10 customer class forecast volumes. Union proposes to apply the 20 year trend methodology currently used to allocate upstream transportation and storage to unbundled customers.

The five objectives and associated weights proposed by Union are a good starting point for establishing a proper weather normalization methodology. The issue for the Board to consider is whether the 20 year trend methodology is a superior forecasting tool than the current 30 year moving average. The impetus to change methodologies is the hypothesis, supported by the evidence of Dr. Weaver, of a global warming trend.

Dr. Weaver's evidence does not support any particular weather normalization method. A number of parties argued for continuation of the 30 year methodology. LPMA and IGUA criticized the statistical analysis done by Union and argued for the continuation of the current practice, or a 20 year method with various proposed revenue adjustment mechanisms. Many parties pointed out that the 20 year proposed methodology would result in a net increase in rates.

IGUA and FONOM argued for a phasing in of any change in methodology. Union rejected this proposal and claimed that this would result in it failing to recover its costs, except during colder than normal weather.

Ratepayers are at risk for unutilized demand charges if the methodology overforecasts HDDs, but the ratepayers are also at risk for the cost of increased winter spot purchases if the methodology underforecasts HDDs.

The Board is concerned with the lack of clarity with respect to the statistical evidence. A number of parties explored whether an estimator derived from ordinary least squares was more or less efficient than using a more sophisticated regression technique. Union's inability to respond clearly is of concern, especially given the large impact that the proposed change in methodology has on its revenue requirement.

Both the 20-year trend and the 30-year average normalization methodologies have advantages in their application. The 20-year trend may track more through the middle of the data and will respond more quickly to changes in short-run trends, but will be more volatile. The 30-year average will respond more slowly to changes but it will be less volatile.

Union was unable to demonstrate that its proposal provided a clear and unambiguous improvement over the 30 year methodology. Nor is the Board convinced that the cited case: *Hemlock Valley Electrical Association* v. *British Columbia Utilities Commission* provides any precedent as to whether it is open to the Board in this case to choose a phased in approach. The OEB Act gives the Board clear authority to adopt any methodology it considers appropriate when setting rates.

In order to test the suitability of changing the normalization methodology, and in consideration of the principle of minimizing rate shock, the Board will allow Union, for 2004, to forecast HDDs based on a 70:30 weighting of the 30-year average forecast and 20-year trend forecast respectively. For each year thereafter, the Board will consider 5% declines and inclines to the weighting of the 30 year and 20 year methodology respectively until such time as a 50:50 weighting is in place.

With respect to operational planning, the Board directs Union to use the same forecast for operations planning as is used all other purposes. The Board also directs Union to report on the outcomes of using the hybrid model annually.

2.3 AFFILIATE RELATIONS

Union's Request

Union seeks to recover in rates the costs it incurs as a result of its shared services arrangements with its affiliates. These costs are $28.7 million in total.

Background

Duke Energy Corporation ("Duke") completed the purchase of Westcoast Energy Inc. ("WEI"), the parent company of Union, in March 2002. Following this transaction, Union became a participant in Duke's shared services business model. The use of this model results in the sharing of a broad range of senior management and support services across Duke's many business units, creating inter-company transactions between the Duke business units as they pay for services received, and charge for services provided to other units.

Union has previously shared services with affiliated companies through the WEI Corporate Centre. Under the Duke shared services business model, to which it is

UNDERTAKING J2.1

UNDERTAKING

Tr: 53

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.

RESPONSE

The Company conducted a series of information meetings in June 2005 that all customers in Rates 100 and higher were invited to attend. One of the topics covered in these meetings was an overview of the natural gas industry. This was intended as an education session for these customers. A component of this overview was a general discussion on risk management and what different hedges can do for managing price volatility. The presentation also touched briefly on Enbridge Gas Distribution's risk management activities, highlighting the objective of the program being to reduce volatility, not cost. The presentation did not however make specific reference to the necessity, if any, for system gas customers to undertake their own risk management.

Witnesses: D. Charleson
K. Irani

UNDERTAKING J2.2

UNDERTAKING

Tr: 55

Advise whether EGDI obtains financial instruments or mechanisms for risk management program from any affiliates or related companies.

RESPONSE

Enbridge Gas Distribution has not obtained any hedge instruments in support of its risk management activities from any affiliate or related company.

Witnesses: D. Charleson
K. Irani