Last update on Feb. 28/07

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	
5.1	BREAKDOWN FOR ELECTRONIC PROGRAM DEFERRAL ACCOUNTS	**February 2, 2007**
5.2	DOCUMENT ENTITLED "ABC SERVICE FOR LARGE-VOLUME CUSTOMERS"	
5.3	COPY OF PAGE 43 OF EB-2006-0021 GENERIC DSM DECISION WITH REASONS	
6.1	COPY OF BUSINESS WEEK ARTICLE DATED JANUARY 29, 2007	**February 5, 2007**
6.2	PRICING SUPPLEMENT TO PROSPECTUS	
6.3	POLLUTION PROBE CROSS-EXAMINATION REFERENCE BOOK	
6.4	BUNDLE OF MATERIALS PROVIDED BY MR. POCH	
6.5	PAGES 32 AND 33 FROM EB-2006-0021	
6.6	PHASE I GENERIC DSM DECISION DATED AUGUST 26, 2006, IN EB-2006-0021	
7.1	DECISION AND ORDER OF THE BOARD IN RP-2002-0158	**February 6, 2007**
7.2	LETTER FROM MR. THOMPSON FROM MR. CASS DATED FEBRUARY 2, 2007	
7.3	EB-2005-0001 DECISION	
7.4	UPDATED CALCULATIONS SHOWING END-OF-DECEMBER RESULTS	
7.5	EXCERPT FROM BOARD’S DECISION IN EBRO 479	
	NO EXHIBITS WERE FILED	**February 9, 2007**

K	Exhibits filed at the Hearing	Date Filed
9.1	18 LETTERS FROM CONTRACTORS	**February 12, 2007**
9.2	ONE-PAGE PHOTO	
9.3	WEB PAGE FROM ENERGYLINK SITE ENTITLED "NEED A CONTRACTOR?"	
9.4	SPREADSHEET PROVIDED BY MR. SHEPHERD	
9.5	INTERNAL PRESS RELEASE	
9.6	LETTER DATED AUGUST 8, 2006	
9.7	LETTER DATED NOVEMBER 8, 2006	
9.8	CROSS-EXAMINATION MATERIALS OF UNION ENERGY LIMITED PARTNERSHIP	
10.1	PRODUCE PROPOSALS OR BUSINESS PLANS RELATING TO ENERGYLINK OR TO THE EARLIER VERSION OF THAT ENTITY, PROJECT ATOCHA	**February 13, 2007**
KX10.2	ANSWER THE QUESTION POSED BY MS. CRAIN, WHETHER CREDIT APPROVAL IS GRANTED BY ESI ON THE SPOT IN CUSTOMER’S HOME	
11.1	DOCUMENT ENTITLED "TRANSCRIPT CLARIFICATION, DAY 9, TRANSCRIPT 172 AND 173."	**February 19, 2007**
11.2	DOCUMENT ENTITLED "TRANSCRIPT CLARIFICATION, DAY 7, TRANSCRIPT 93."	
12.1	RECALCULATION OF BETA ESTIMATES FROM EXAMINATION-IN-CHIEF OF EGDI WITNESS DR. CARPENTER	**February 20, 2007**
12.2	AVERAGE ACTUAL BETA ESTIMATES FOR THE FIRMS USED IN THE EXAMINATION-IN-CHIEF BY EGDI WITNESS DR. CARPENTER	
12.3	CV OF DR. BOOTH	
12.4	BRIEF OF MATERIALS PROVIDED BY MR. CASS	
12.5	DECISION OF BCUC DATED AUGUST 4, 1994	
12.6	BROCHURE	

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		February 16, 2007
3.2	FILE ANALYSIS OF IMPACT OF MOVING RATE 1 TO REVENUE-T		February 9, 2007
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		February 16, 2007
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		February 9, 2007
3.5	PRODUCE FORECAST PRICE FOR 2007		February 16, 2007
3.6	UPDATE TABLE 1 AT EXHIBIT I, TAB 2, SCHEDULE 27, PAGE 2		February 16, 2007
3.7	TO ADVISE THE IMPACT OF A ONE PERCENT CHANGE IN THE PRICE OF GENERAL SERVICE VOLUMES		February 16, 2007
3.8	TO PROVIDE A PRICE PER M^3 THAT CORRESPONDS TO THE 8.5 PERCENT UNDER THE 2007		February 16, 2007
3.9	ADD THREE COLUMNS TO TABLE 4 ACTUAL THROUGHPUT VOLUMES; WEATHER NORMALIZED THROUGHPUT VOLUMES; BOARD-APPROVED THROUGHPUT VOLUMES		February 16, 2007
3.10	TO PROVIDE ADJUSTED R-SQUARE VALUES FOR MODELS DESCRIBED IN TABLE 6 OF EXHIBIT C2, TAB 4, SCHEDULE 1		February 16, 2007

J	Undertakings	Hearing Date	Response Filed
		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		February 16, 2007
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		February 16, 2007
4.3	PRODUCE THE TREND LINE ON ACTUAL DATA FROM 1965 TO 2007 FOR ALL THREE REGIONS		February 16, 2007
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		February 16, 2007
4.5	PROVIDE 20-YEAR DATA SET THAT TRACKS VARIATIONS FROM ACTUAL TO BOARD-APPROVED EACH YEAR FOR DEGREE DAYS AND FOR ROE		February 16, 2007
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		February 16, 2007
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		February 16, 2007
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		February 26, 2007
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		February 16, 2007
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		February 26, 2007
		February 2, 2007	
5.1	PROVIDE INFORMATION TO SHOW 1.8 PERCENT DECLINE IN AVERAGE USE BETWEEN 2001 AND 2005		February 16, 2007
5.2	A SIMILAR THING FOR THE GAS PRICE IMPACTS SHOWN IN TABLES 4, 5 AND 6, EITHER INDIVIDUALLY OR IN AGGREGATE, OF ADJUSTING THE REAL COMMERCIAL PRICE TO REFLECT ACTUAL 2006 AND THE UPDATED FORECAST FOR 2007/2008		February 26, 2007

J	Undertakings	Hearing Date	Response Filed
5.3	PROVIDE THE IMPACT ON THE DEFICIENCY OF USING A DEGREE DAY METHODOLOGY THAT CONSISTS OF A 50/50 WEIGHTING BETWEEN THE 20-YEAR TREND AND THE EXISTING APPROVED DE BEVER METHODOLOGY		February 16, 2007
		February 5, 2007	
6.1	REDO TABLE 4 OF COMPANY'S EVIDENCE AT E2, TAB 1, SCHEDULE 1, WITH NORMALIZED RETURN ON EQUITY FOR YEARS 1993 TO 2005		February 6, 2007
6.2	TO PROVIDE THE BUDGET FOR THE 2006 BUSINESS DEVELOPMENT AND STRATEGY, AS ADJUSTED OR INCORPORATING THE CAPITALIZED AMOUNT REFERRED TWO FOR (1) THE PREFILED ESTIMATE AND (2) FOR THE ACTUAL	February 26, 2007	February 26, 2007
6.3	PROVIDE REASONS FOR THE DECREASE IN THE ENERGY OPPORTUNITIES BUDGET FROM THE 2005 ACTUAL FIGURE TO THE 2006 BRIDGE YEAR ESTIMATE OF 1.177 MILLION, AS FOUND ON TABLE 1 ON PAGE 2 OF 10 IN THE POLLUTION PROBE DOCUMENT BOOK, TAB 3		February 26, 2007
		February 6, 2007	
7.1	TO PROVIDE ADDITIONAL YEAR 2006 TO UNDERTAKING J6.1		February 16, 2007
7.2	TO REVIEW EVIDENCE OF RP-2002-0158 AND CONFIRM WHETHER THERE WERE CHANGES IN BUSINESS RISK SUFFICIENT TO JUSTIFY AN INCREASE IN EQUITY RATIOS		February 16, 2007
7.3	RECALCULATE THE INTEREST COVERAGE RATIOS IN COLUMN 9 IN ITEMS IN EXHIBIT E2, TAB 1, SCHEDULE 1, APPENDIX 3, ASSUMING THAT AMOUNTS PAID FOR CORPORATE COST ALLOCATION IN 2002-2006 INCLUSIVE ARE TO BE ADDED TO THE AMOUNTS IN COLUMN 8, ALONG WITH THE AMOUNTS PAID TO CWLP IN EXCESS OF BOARD-ALLOWED AMOUNTS FOR CUSTOMER SUPPORT		February 26, 2007
7.4	2006 ACTUALS FOR LINE 1		February 26, 2007
7.5	TO PROVIDE CLARIFICATION FOR COLUMN 7		February 26, 2007
7.6	EXPLAIN THE DIFFERENCE IN VOLUMES ANTICIPATED FROM WATER HEATERS ON LINES 7, 10 AND 11		February 26, 2007
7.7	TO VERIFY TRC AMOUNT OF $10.2 MILLION FOR FURNACE AND WATER HEATER LINES		February 26, 2007
7.8	TO PROVIDE TRC FOR FIREPLACES UNDER ENERGYLINK PROGRAM		February 26, 2007

J	Undertakings	Hearing Date	Response Filed
		February 9, 2007	
8.1	EITHER CONFIRM FIREPLACE AND LIFESTYLE PRODUCTS' TRC, WHEN DELIVERED THROUGH THE ENERGYLINK MECHANISM, IS NEGATIVE; OR PROVIDE A CALCULATION OF THE TRC FOR EACH OF THOSE PRODUCTS INCLUDING ATTRIBUTABLE PROGRAM COSTS OF THE ENERGYLINK PROGRAM		February 26, 2007
		February 12, 2007	
9.1	PROVIDE BINDER OF SCRIPTS RELATING TO ENERGYLINK		February 26, 2007
9.2	REPLACE NUMBERS IN THE ENERGYLINK SECTION OF K9.4 TO RECONCILE WITH PREVIOUS EVIDENCE		February 26, 2007
9.3	TO E-MAIL THE LETTER RECEIVED FROM HVAC COALITION INDICATING THAT THEY DIDN’T WANT REFERENCE TO THEIR NAME ON THE ENBRIDGE WEBSITE		February 26, 2007
9.4	[NOT USED]		February 26, 2007
9.5	TO FILE THE FORMULA TO DETERMINE WHETHER THE COMPANY PASSES THE SOUND FINANCIAL HEALTH TEST		February 26, 2007
9.6	PROVIDE NUMBER OF CONTRACTORS WHO TICKED BOXES FOR EACH OF THE NINE PRODUCTS NOT CURRENTLY INCLUDED IN THE PROJECT		February 26, 2007
		February 13, 2007	
10.1	PROVIDE NUMBER OF CALLS RECEIVED BY ENERGYLINK FOR GAS WATER HEATERS, TO PURCHASE GAS WATER HEATERS		February 26, 2007
10.2	PROVIDE FROM CURRENT REFERRALS HOW MANY HAVE RESULTED IN CUSTOMER SWITCHING OUT A NON GAS FURNACE AND BUYING NEW GAS FURNANCE		February 26, 2007
10.3	TO PROVIDE A MONTHLY PROJECTION, IF AVAILABLE, OF NUMBER OF CALLS EXPECTED TO ENERGY LINK IN 2007		February 26, 2007
10.4	(UNUSED)		
10.5	PROVIDE DOLLAR AMOUNT SPENT ADVERTISING ENERGYLINK TO DATE AND PROJECTED FOR 2007		February 26, 2007
10.6	TO PROVIDE PERCENTAGE OF EXPENDITURES FOR CO-OP ADVERTISING		February 26, 2007
10.7	TO PROVIDE A SPREADSHEET SHOWING IN DETAIL HOW FORECASTED VOLUMES OF 8 MILLION CUBIC METERS IN YEAR ONE AND THE FORECASTED PARTICIPANTS WERE ARRIVED AT		February 20, 2007
10.8	TO ADVISE HOW MANY CALLS TO DATE OF THE 1,770 REFERRALS WERE FROM NON-CUSTOMERS ON MAIN		February 26, 2007

J	Undertakings	Hearing Date	Response Filed
10.9	TO CHECK FOR A WRITTEN SUBMISSION BY ENBRIDGE GAS DISTRIBUTION TO EITHER ENBRIDGE SOLUTIONS OR ENBRIDGE INC. REGARDING PROVIDING FINANCING FOR THE ENERGYLINK PROGRAM		February 20, 2007
		February 19, 2007	
11.1	TO CALCULATE THE MAXIMUM RATEPAYER BENEFIT THAT COULD OCCUR FROM FULLY UTILIZING THE ENVELOPE AS PROPOSED UNDER THE PROPOSAL		
11.2	TO UPDATE NET PRESENT VALUE FOR ENERGYLINK IN EXHIBIT I, TAB 1, SCHEDULE 25, PAGE 3 OF 3, TO INCLUDE OVERHEADS AND CAPITAL EXPENDITURES		
11.3	TO CHECK WITH THE RISK-MANAGEMENT DEPARTMENT TO DETERMINE IF THERE ARE ANY INCREASED INSURANCE PREMIUMS AS A RESULT OF THE ENERGYLINK PROGRAM		
11.4	TO PROVIDE A DETAILED BUDGET OF THE CAPITAL AND O&M EXPENDITURES FOR 2007		
11.5	RECONCILE THE PREDICTED 8 MILLION M3 AND ADDED LOAD FROM ENERGYLINK WITH WHAT IS SHOWN ON TABLE 3 OF EXHIBIT 1, TAB 3, SCHEDULE 1, PAGE 8		
11.6	PROVIDE DIFFERENCE IN REVENUE DEFICIENCY USING 32.3 AS TOTAL INCREASE IN VOLUME FOR 2007		
11.7	TO PROVIDE THE SCRIPT OF ANY RADIO ADS FOR THE ENERGYLINK PROGRAM		February 26, 2007
11.8	IMPACT OF SMART METERS ON FORECAST		
11.9	TO PROVIDE NUMBER OF MEMBERS OF HRAC WHO OPERATE WITHIN THE ENBRIDGE GAS DISTRIBUTION FRANCHISE AREA		
11.10	PROVIDE NUMBER OF CONTRACTORS IN THE ENBRIDGE GAS DISTRIBUTION FRANCHISE AREA THAT SUPPORT THE HVAC COALITION		
11.11	TO PROVIDE MISSING MATERIAL		
11.12	TO PROVIDE FINAL CONTRACT WITH SYNERGY MARKETING		
		February 20, 2007	
12.1	PROVIDE THE DATA BEHIND EXHIBIT K12.1		
12.2	TO ADVISE WHETHER THE CHART AT TAB 10 OF EXHIBIT K12.4 REQUIRES ANY CORRECTION IN RELATION TO TERASEN GAS		
12.3	TO ADVISE WHETHER THE CHART AT TAB 10 OF EXHIBIT K12.4 REQUIRES ANY CORRECTION IN RELATION TO TERASEN GAS		

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%?

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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%

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[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.

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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.

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[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.

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.

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

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

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

The Pricing Mechanism

Stakeholders' Views

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

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

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

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

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

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

The Board's Conclusions

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

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

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

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

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

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

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

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

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

Long-Term Supply and Transportation Contracts

Stakeholders' Views

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

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Risk Management Impact on WACOG & PGVA

Union Gas

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

Conclusions:

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

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

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

Ontario Energy Board
FILE No. EB-2006-0034
EXHIBIT No. K2.3
DATE January 29, 2007
08/99

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Schedule J1.4.2

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

Union Gas

Alberta Border Reference Price

Effective Date	Alberta Border Approved WACOG (Cdn cents / m^3) (A)	Alberta Border Approved WACOG Excluding Forecast Risk Management (Cdn cents / m^3) (B)	Forecast RM vs No RM (A vs B)
Jan-03	18.6	18.6	0%
Mar-03	21.9	21.9	0%
May-03	24.3	24.2	0%
Jul-03	25.1	24.8	1%
Oct-03	21.9	20.7	5%
Jan-04	20.6	20.1	3%
Apr-04	23.8	23.3	2%
Jul-04	27.3	27.1	1%
Oct-04	27.8	27.1	2%
Jan-05	29.4	29.6	-1%
Apr-05	27.0	26.3	3%
Jul-05	30.2	29.5	2%
Oct-05	34.2	33.5	2%
Jan-06	40.9	40.9	0%
Total			
Average	**26.6**	**26.3**	**1.5%**
Standard Deviation	**5.6**	**5.7**	**-1%**

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)	Difference Between RM and No RM (cents / m^3) (E-F)	(E-F) as % of Average Cost of Gas (G)
2.0	1.9	0.1	0%
2.6	4.3	-1.7	-7%
0.1	0.0	0.1	0%
-0.4	-0.6	-0.2	-1%
-0.3	-0.6	-0.3	-1%
1.3	1.0	0.3	1%
0.2	0.3	-0.1	0%
-1.0	-1.0	0.0	0%
-0.3	-0.2	0.1	0%
-1.1	-1.3	-0.2	-1%
0.0	0.0	0.0	0%
0.2	0.3	-0.1	0%
2.5	3.0	-0.5	-2%
-1.6	-1.7	-0.1	0%
Abs Value Avg **1.0**	Abs Value Avg **1.2**		**-1%**
1.3	**1.6**		

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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.2.4

EB-2006-0034

Cross-Examination Materials

On

Risk Management

Energy Probe Research Foundation

January, 2007

Ontario Energy Board

FILE No. EB-2006-0034

EXHIBIT No. K.2.4

DATE January 29, 2007

08/99

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.

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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

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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,

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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 <u>its</u> 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.

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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]

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[167] 38 Tr. 165

[168] *Ibid*

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

[170] Ex. L8-2, p 12

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

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

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

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[171] 38 Tr. 152 and 166-167

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

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

[174] 38 Tr. 121 and 171

[175] 38 Tr. 169

[176] 38 Tr. 155

[177] 38 Tr 172

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

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

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

D. Conclusion

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

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

[179] 5 Tr. 71-72

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

[181] 38 Tr. 146-148

[182] Ex. J5.6

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

7. RATE BASE

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

8.1 Capital Budget for the 2006 Test Year including capitalized O&M expenses

8.2 Information Technology Capital Budget including Energy Transaction, Reporting, Accounting and Contracting (EnTrac), and Meter Management and Large Volume Meter Data Processing (EnMar) projects

8.3 Appropriateness of the capital budget "placeholder" for power generation project RFPs

8.4 Appropriateness of the capital budget for System Improvements and upgrades, including the budget increases in system expansion and reinforcement projects and the Accelerated Bare Steel and Cast Iron Replacement Program

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

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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

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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

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> order to gain the opportunity to achieve lower prices."

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

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

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

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

Then it goes on to say:

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

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

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

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

MR. CHARLESON: I'm not --

MR. ADAMS: -- is that fair?

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

MR. ADAMS: From the 1995 study --

MR. CHARLESON: That's --

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

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

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

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

MR. ADAMS: Right.

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

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

MR. CHARLESON: That sounds about the right number.

MR. RUBINO: Subject to check.

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

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

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

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

MR. RUBINO: Yes?

MR. ADAMS: Specifically, with regard to --

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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

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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

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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

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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

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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 --

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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

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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?

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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

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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

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> 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

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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.

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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

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-- 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

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management program. If there was no risk management program and customers, instead, relied on equal billing to manage the volatility or to mitigate volatility, over the course of the year, it's true month over month what they pay will be smooth and there won't be dramatic fluctuations in there.

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

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

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

MR. CHARLESON: True.

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

MR. CHARLESON: Correct.

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

MR. CHARLESON: Yes, that's correct.

MR. ADAMS: So there is really no difference except

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

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

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

MR. RUBINO: That's correct.

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

MR. RUBINO: Our own staff.

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

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

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

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

MR. CHARLESON: Yes, there is that risk.

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

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

MR. ADAMS: Thank you.

Those are my questions.

MS. NOWINA: Thank you, Mr. Adams.

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

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

MS. NOWINA: Ms. DeMarco?

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

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

MS. DeMARCO: Absolutely, Madam Chair.

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

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

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

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

MR. O'LEARY: Madam Chair.

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

Table 2

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

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

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

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

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Filed: 2006-11-09
EB-2006-0034
Exhibit I
Tab 5
Schedule 19
Page 1 of 2

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

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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

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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

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Filed: 2004
EB-2004-0492
Exhibit Q2-2
Tab 1
Schedule 1
Page 1 of 3

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

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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

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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

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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

Filed: 2006-11-09
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Exhibit I
Tab 5
Schedule 16
Page 1 of 1

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

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Filed: 2006-11-09
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Exhibit I
Tab 5
Schedule 17
Page 1 of 2
Plus Attachment

ENERGY PROBE INTERROGATORY #17

INTERROGATORY

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

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

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

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

RESPONSE

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

Witnesses: D. Charleson
D. Small

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

Witnesses: D. Charleson
D. Small

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Table 1

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

loss/gain
2.7

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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

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Ipsos Reid

Enbridge Gas Distribution

Customer Threshold for Gas Supply Volatility Study

December 2004

ENBRIDGE

CR-374

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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

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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…

Affect of Price Decrease on Strategy Preference

- 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.

Affect of Price Decrease on Strategy Preference

- 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.

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Prices and Regulation

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Natural Gas Supplier Awareness

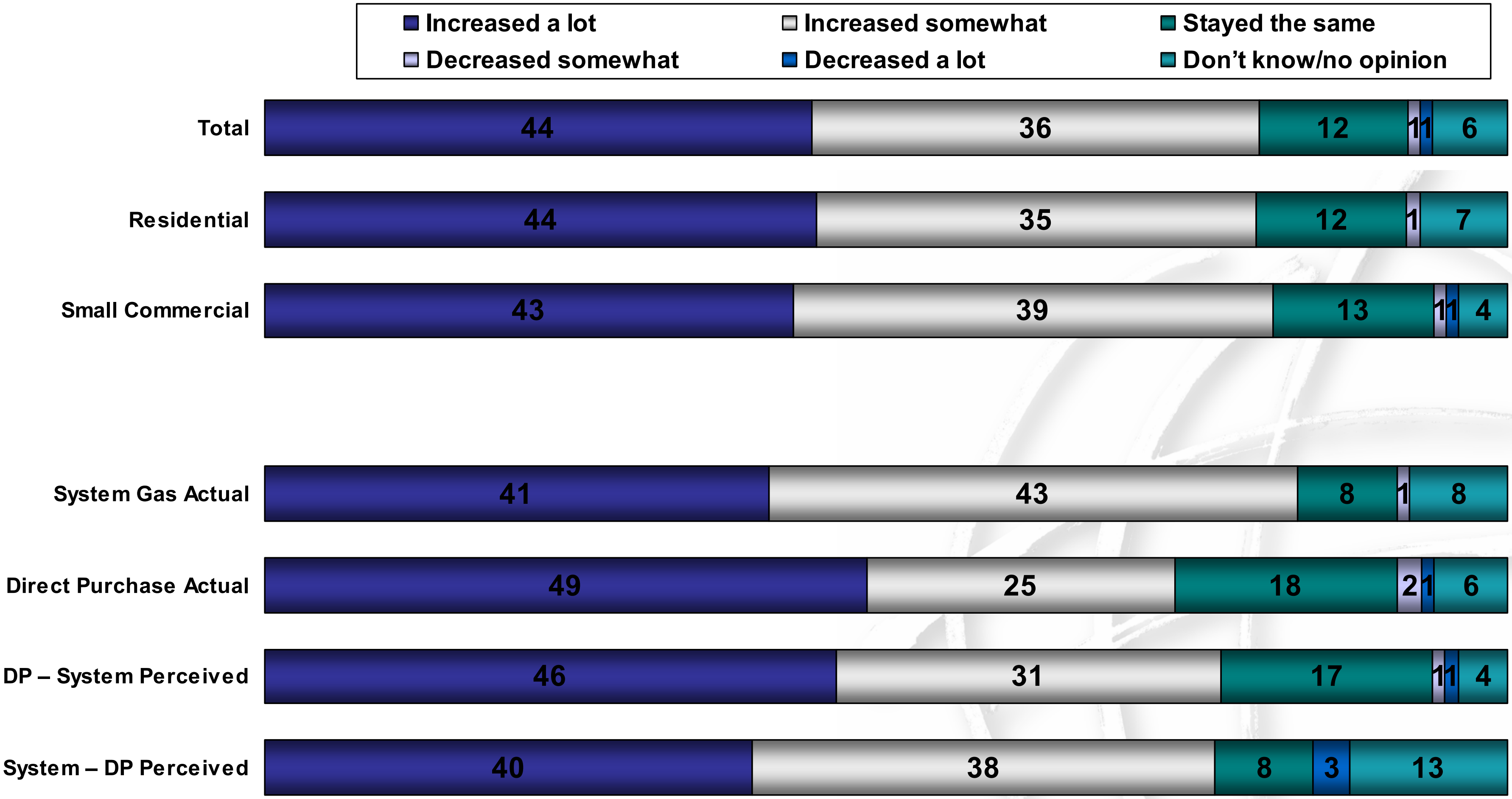
- Nearly six-in-ten (58%) direct purchase customers continue to believe that they purchase their natural gas commodity from Enbridge Gas Distribution. Less than a third (32%) are aware that they are direct purchase customers.
- Comparatively, the majority (90%) of system gas customers identified Enbridge 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

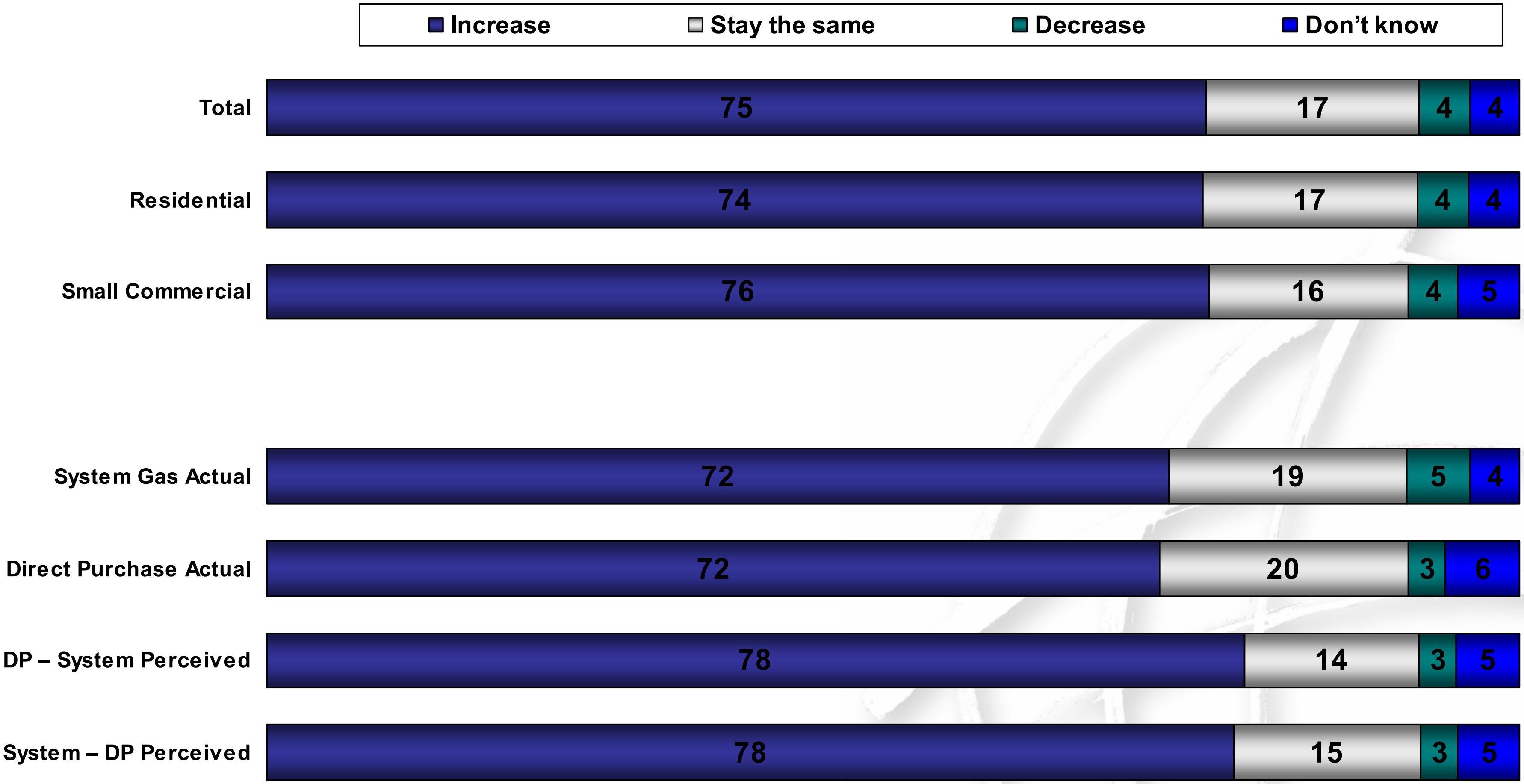
Four-in-five customers believe that the market price for the natural gas commodity has increased over the past two years (80% increased a lot/somewhat) and one-in-ten believe it has stayed the same (12%). These results are consistent for both residential and small commercial customers. However, System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

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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?

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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?

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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

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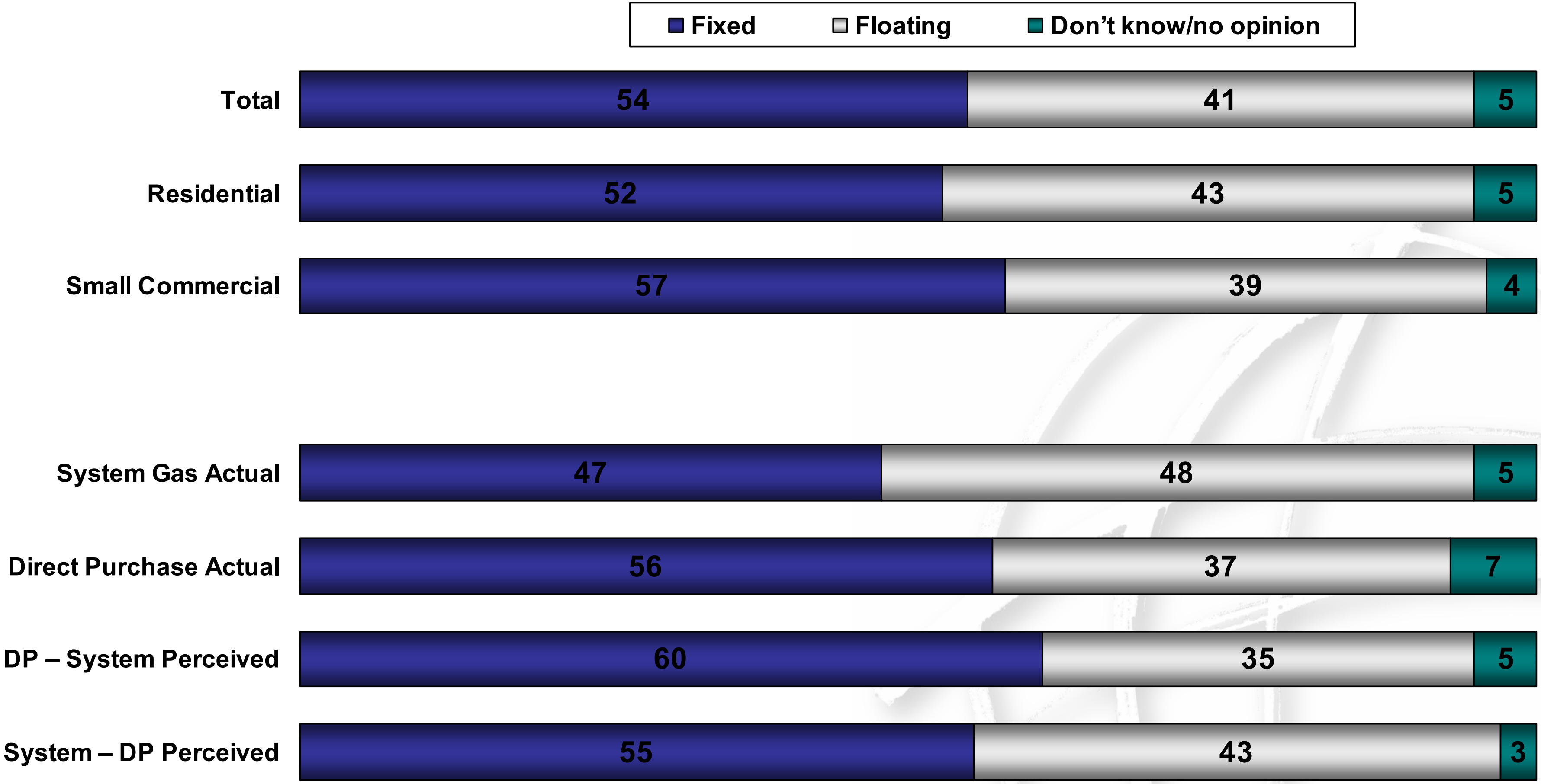
Sensitivity to Price Volatility

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?

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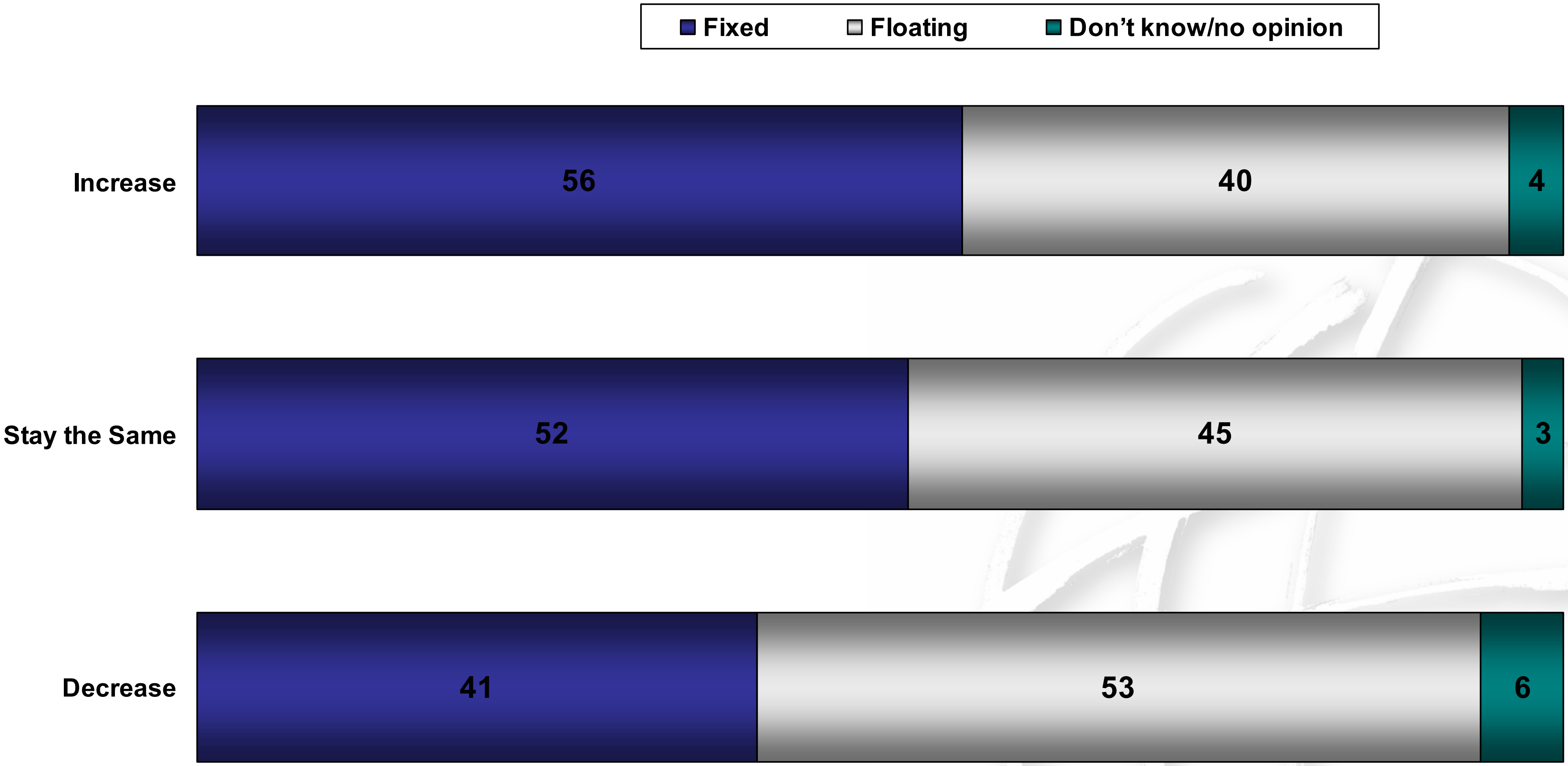
Fixed Price Versus Floating Rate And Perceptions of the Future of Natural Gas Prices

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?

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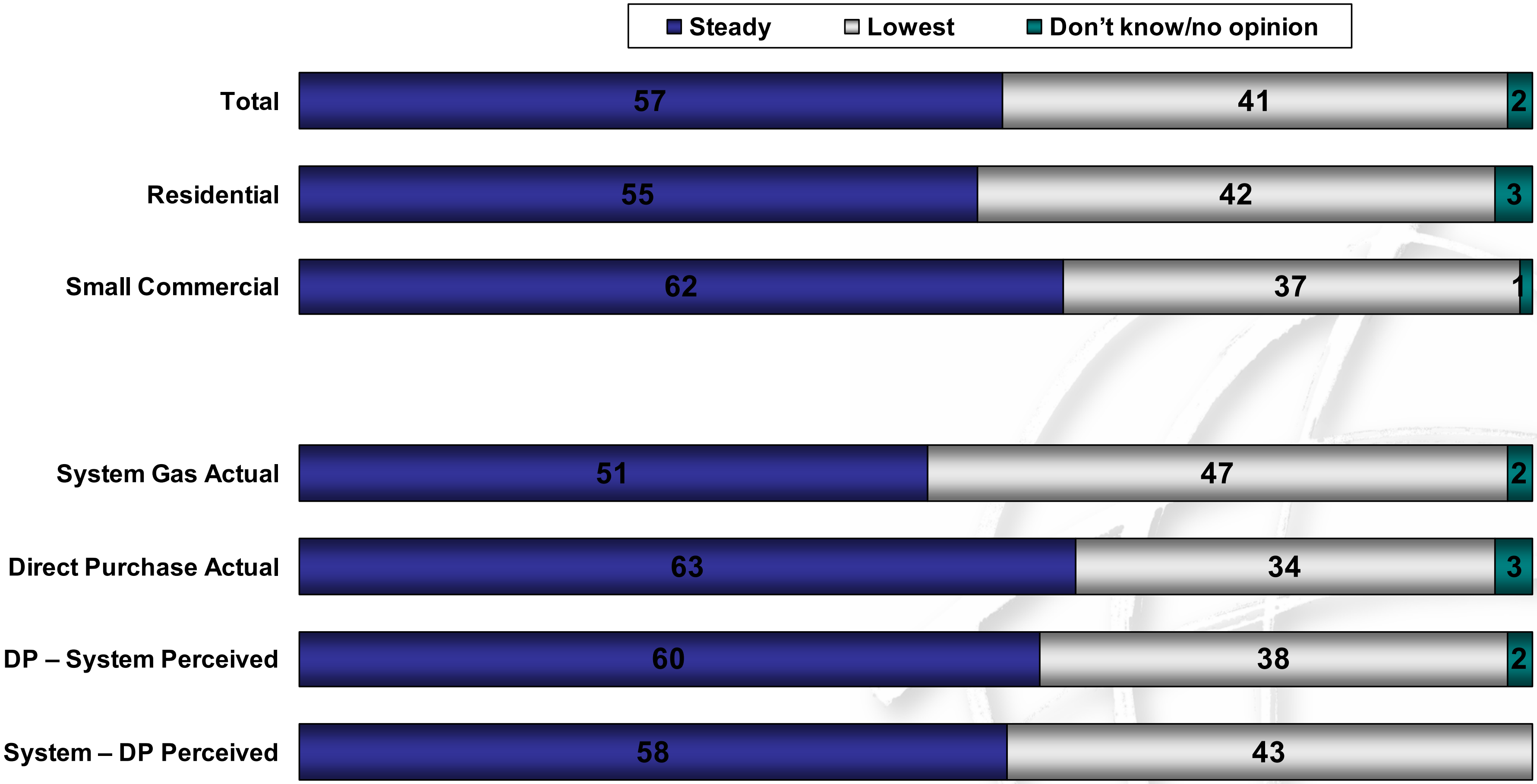
Steady Price Versus Lowest Price

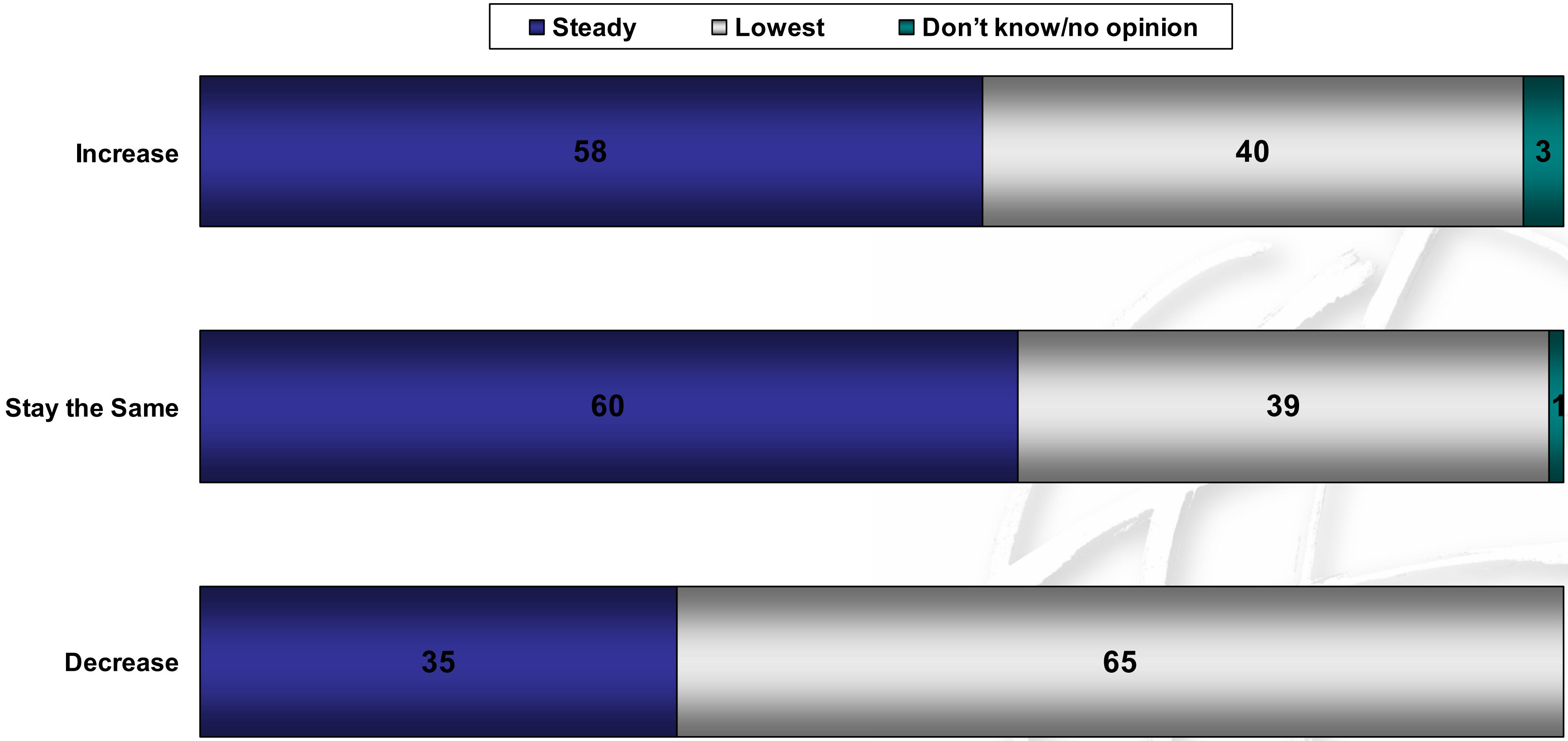
It is more important to maintain a steady price than to try to obtain the lowest price for more than six-in-ten (62%) small commercial customers, somewhat more than residential customers (55%).



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?

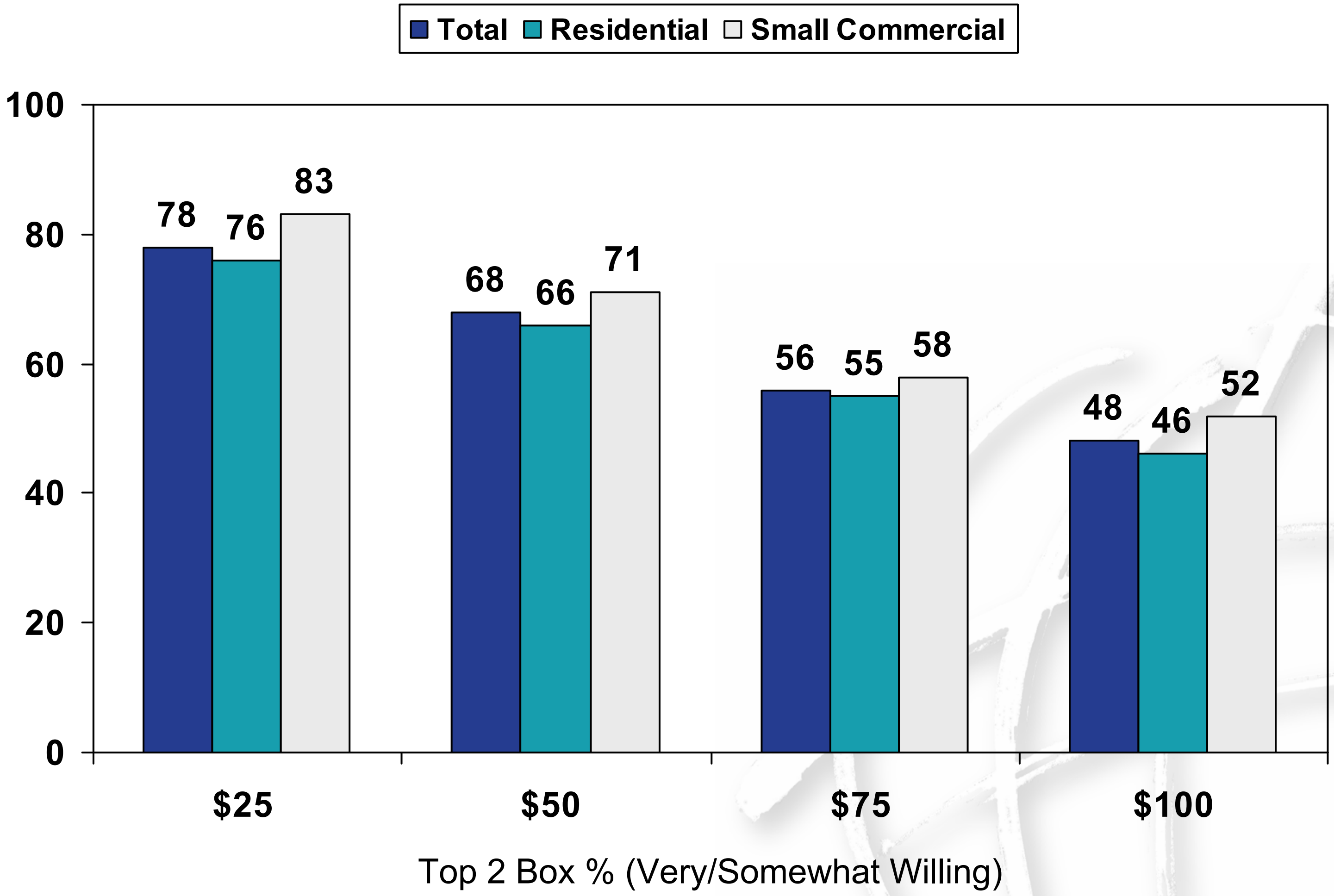
Willingness for Bill Fluctuation

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 <u>maximum</u> of [INSERT ITEM]?

Willingness for Bill Fluctuation



	Total	Residential	Small Commercial
$25	78	76	83
$50	68	66	71
$75	56	55	58
$100	48	46	52

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]?

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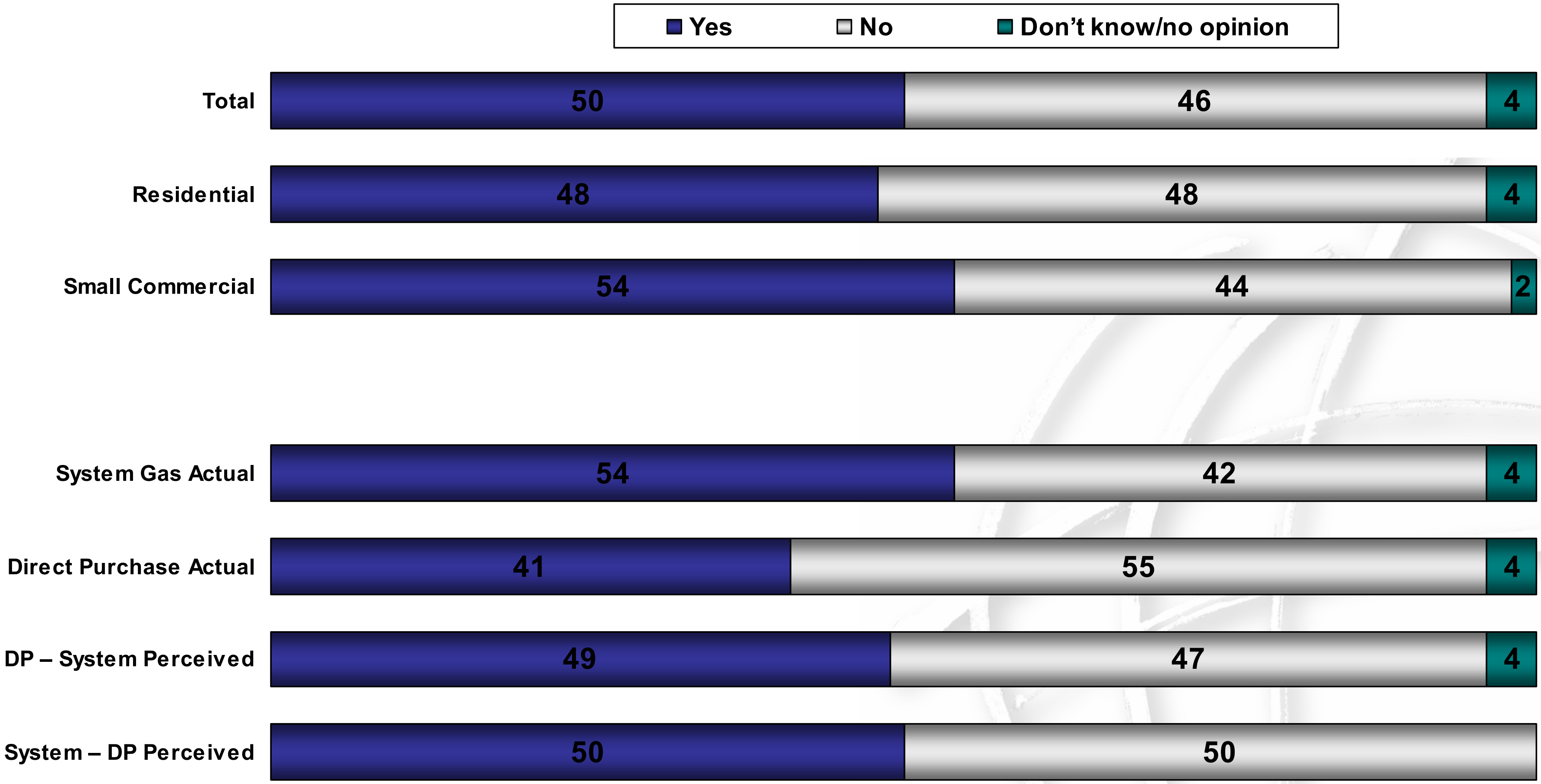
Bill Adjustment Preferences

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?

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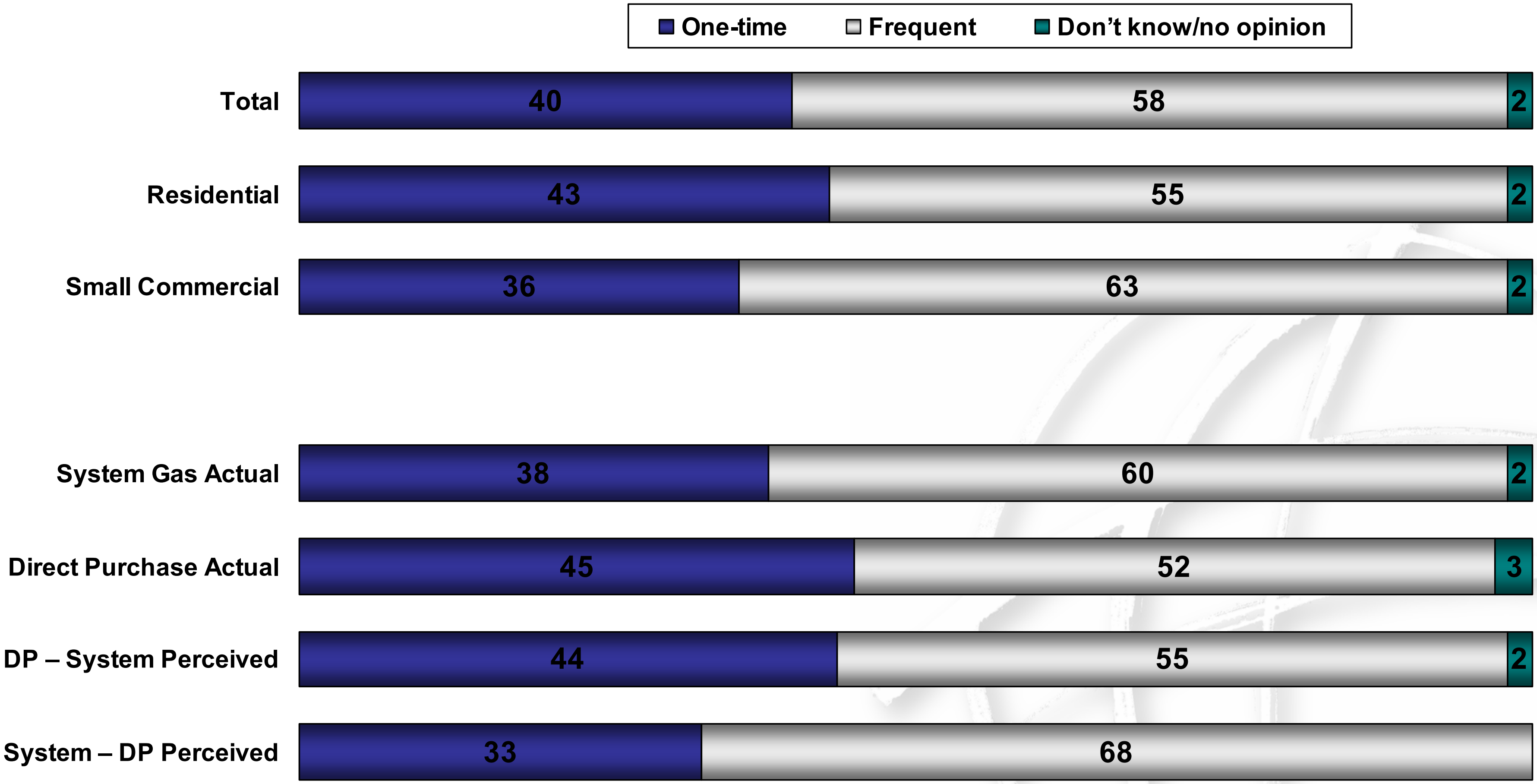
General Preference for Frequency of Bill Adjustments

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?

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Frequency of Bill Adjustments

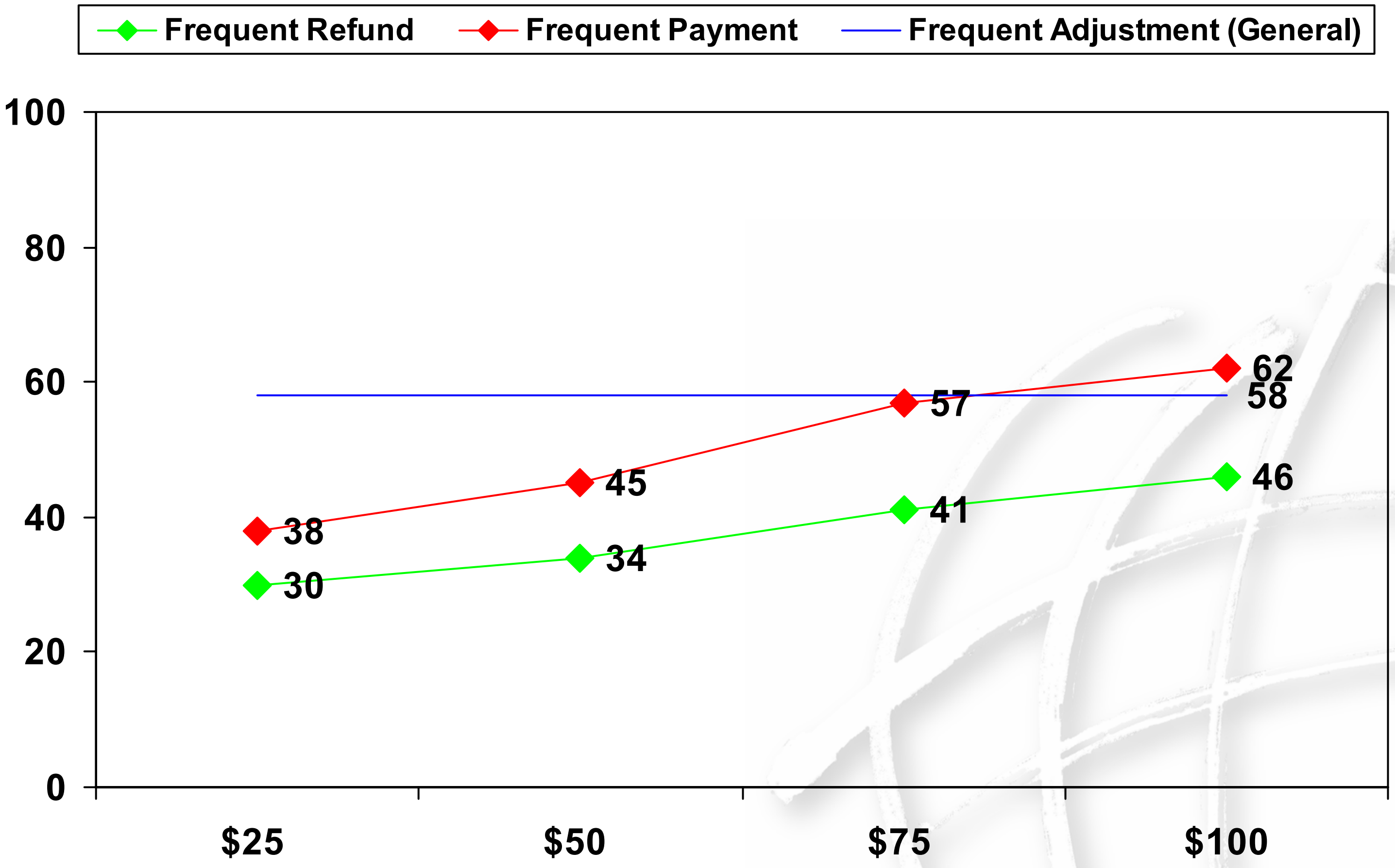
Among customers who would prefer smaller and more frequent adjustments to their bill, most think that the adjustments should be made four times per year (61%).

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?

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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?

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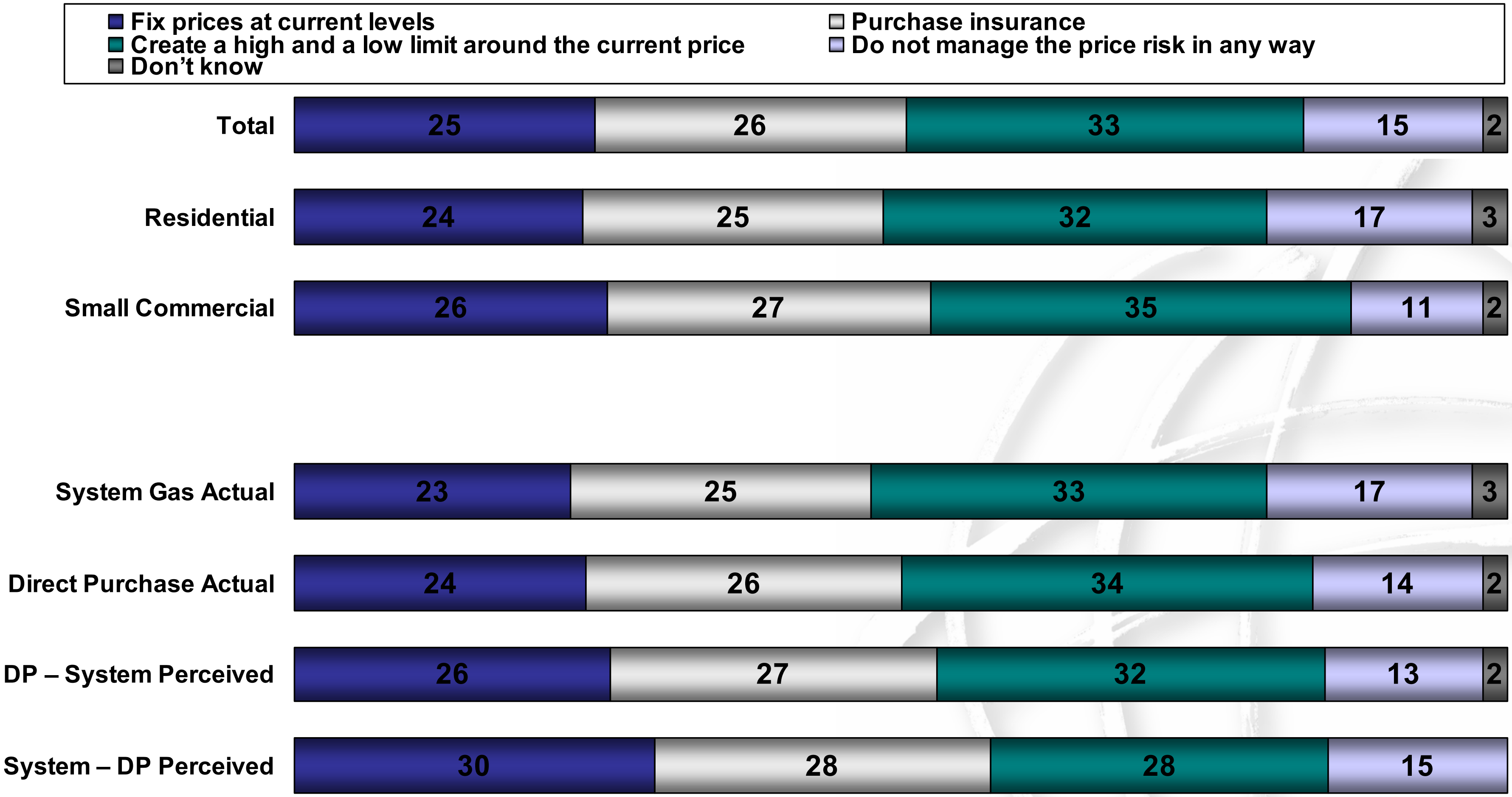
Risk Management

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?

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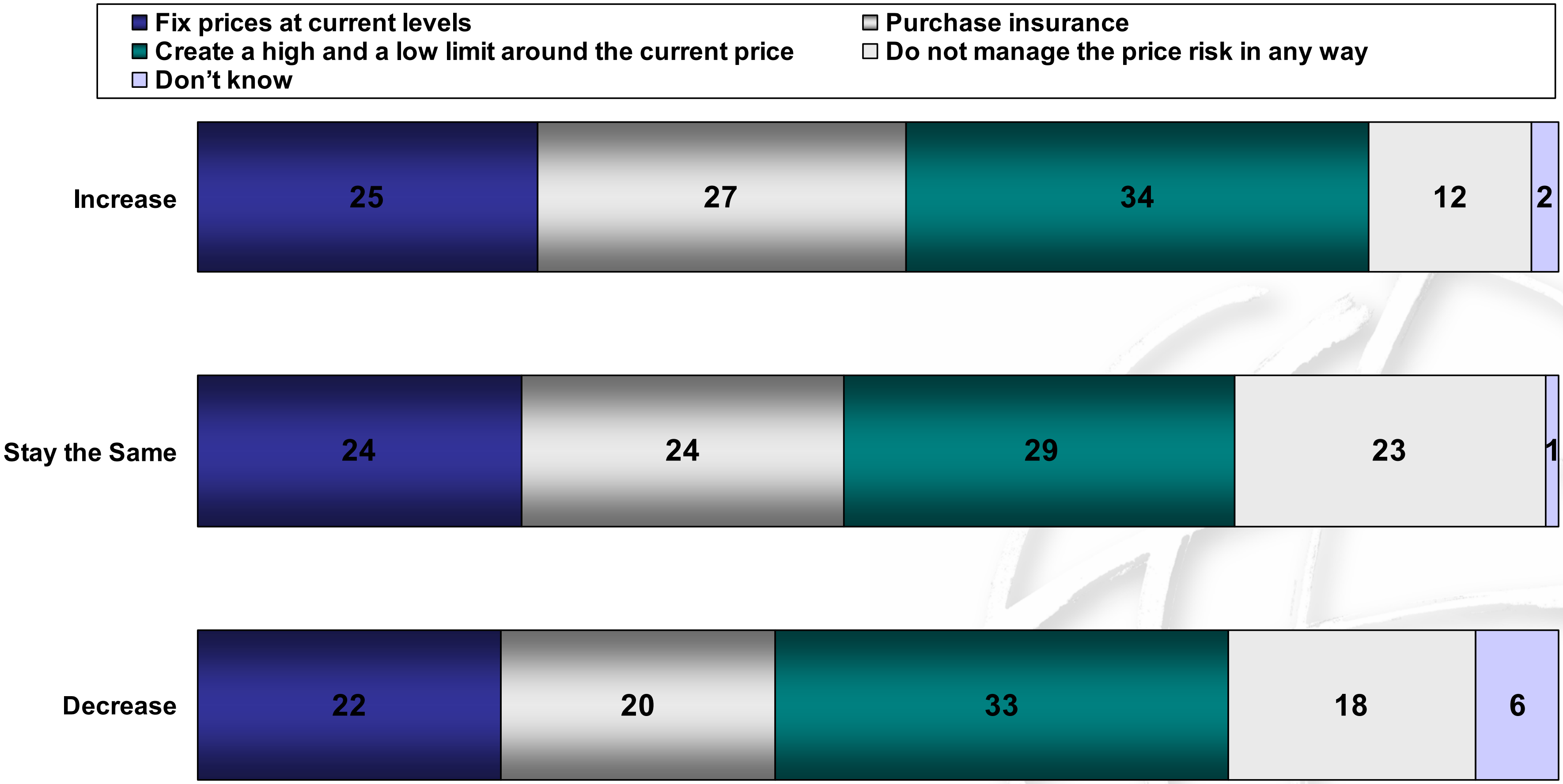
Risk Management Strategy Preference And Perceptions of the Future of Natural Gas Prices

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?

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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%?

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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

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

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

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

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

K 3.1

Original
EB-2005-0001
Exhibit I
Tab 25
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Page 1 of 2
Plus Attachments

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

Ontario Energy Board
FILE No. EB-2006-0034
EXHIBIT No. K.3.1
DATE January 30, 2007
08/99

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.

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Filed: 2004-11-22
RP-2003-0203
Exhibit G3
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REVENUE TO COSTS/
RATE OF RETURN COMPARISONS
SEPT. 30, 2005

(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.	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)	0.36	(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	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	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
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REVENUE TO COST/
RATE OF RETURN COMPARISONS
EXCLUDING GAS SUPPLY COMMODITY
SEPT. 30, 2005

(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.	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 m³)		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	3,408.12	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%	8.19%	-21.04%	-17.04%	9.47%	-16.09%	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

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%	38.36%	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

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

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

(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.	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	42.38	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	0.60	1.05	N/A

ENBRIDGE
Consumers Gas

**Interim Board Order
RP-2001-0032
Exhibit G2
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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

Final Rate Order
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Attachment A

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	(0.67)	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)

		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	1,383.80	740.03	378.70	2.06	119.14	35.09	42.78	2.64	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	0.08	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	42.86	2.68	21.51	27.68	10.72	0.30	0.00	2.41	1.07
4.	Cost of Service	1,395.89	752.91	375.76	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	35.60	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

Original
EB-2005-0001
Exhibit I
Tab 25
Schedule 73
Page 1 of 5
Attachment B

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	1.88	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	1.88	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	629.06	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	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
		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	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%	9.68%	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 8	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	1.56
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	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	1.56
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)

		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	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	14.05	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	0.76	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)

		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.	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	54.86	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 10³ m³)		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

Ontario Energy Board
FILE No. EB-2006-0034
EXHIBIT No. K4.2
DATE February 1, 2007
08/99

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.

Ontario Energy Board
FILE No. RP-2003-0063
UNDERTAKING N3.2
DATE Oct. 15/03
08/99

Ontario Energy Board
FILE No. EB-2006-0034
EXHIBIT No. K4.3
DATE February 1, 2007
06/99

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 ________

EB-2006-0034

Cross-Examination Materials

On

Average Use & Degree Days

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	

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	

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 -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%
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

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[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

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

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

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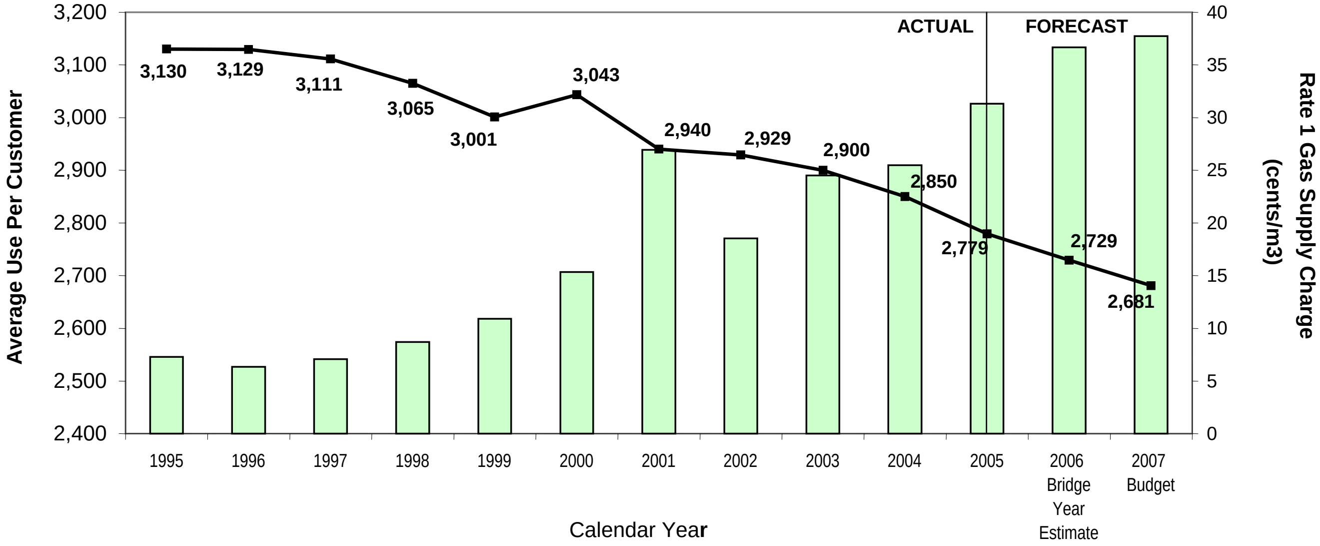
[1] Real Residential Natural Gas Price – Table 2- Exhibit C2, Tab 3, Schedule 1.

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.

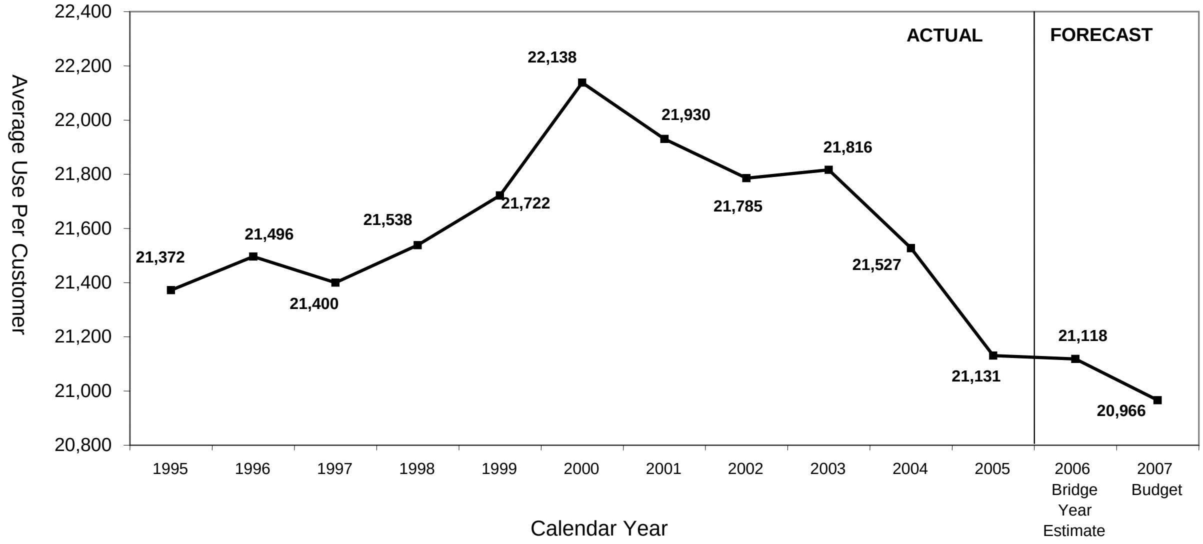
Figure 1
Residential Normalized Average Use (m^3)



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

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.

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.

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 (10^6m^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

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.

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 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

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		

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[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	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	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	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	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

K 5.1

ENBRIDGE GAS DISTRIBUTION INC.
DEFERRAL AND VARIANCE ACCOUNT DETAILS
2006 ELECTRIC PROGRAM EARNINGS SHARING DEFERRAL ACCOUNT (2006 EPESDA)

Line No.		Col. 1 2006 Actual ($000's)
1.	Gross revenue	1,451.7
2.	Material and service cost	(999.5)
3.	Internal resource cost	(102.0)
4.	Net revenue before sharing	350.2
5.	Shareholder portion of net revenues (50%)	(175.1)
6.	Ratepayer portion of net revenues (50%) transferred to the 2006 EPESDA	175.1

Ontario Energy Board
FILE No. EB-2006-0034
EXHIBIT No. K.5.1
DATE February 2, 2007
08/99

ENBRIDGE GAS DISTRIBUTION INC.
DEFERRAL AND VARIANCE ACCOUNT DETAILS
2005/6 GAS DISTRIBUTION ACCESS RULE COSTS DEFERRAL ACCOUNTS (2005/6 GDARCDA) AND 2006 UNBUNDLED RATE IMPLEMENTATION COST DEFERRAL ACCOUNT (2006 URICDA)

Type/Category	Cost (000's)	Purpose
		2005 GDARCDA
GDAR Impact Analysis	$406.0	* Review and analysis of the GDAR rule and it's impact on systems and business process changes that would be required to be compliant. * Estimation of costs that would be incurred in order to implement the GDAR rule.
Total	**$406.0**	
		2006 GDARCDA
Requirements Analysis	$233.7	* GDAR requirements gathering and analysis sessions and development of a project implementation roadmap. A series of joint sessions between Enbridge and all service providers. The work was based on the impact of the GDAR rule and the requirements of the EBT standards published by the Board.
EnTRAC Systems Changes	$2,877.9	* Changes to the EnTRAC system that were required in order to be GDAR compliant. This included the design, development, and unit testing of all required changes including the point-to-point EBT Transaction system.
Customer Care Systems Changes	$1,813.7	* Changes to all Customer Care systems and design and implementation of new internal business processes that were required in order to be GDAR compliant. The system changes were made to CIS, LVB, LVTS, and ICSS to support the EBT standards.
Business Process Changes	$188.6	* Design, documentation and implementation of new business and IT support processes that were required to be GDAR compliant.
Training & Communication	$148.2	* Planning and implementation of a training program for internal and external stakeholders. The development and execution of a communication plan to ensure that all stakeholders were aware of GDAR related activities undertaken by Enbridge.
Quality Assurance	$347.9	* Planning and implementation of a Quality Assurance program to ensure that the systems and business processes changes completed put Enbridge in a position to meet GDAR compliance requirements. This includes working with the Market participants to develop a joint Market Test Plan.
GDAR Cutover Readiness	$65.5	* Planning for GDAR implementation in June, 07. This includes planning and analysis effort to assess all the activities to be performed during the cutover and working with market participants to develop a Market Cutover plan.
IT Infrastructure (Hardware/Software	$761.2	* Hardware, Software licenses, installation, and configuration required for the development, testing, and implementation of GDAR.
Program/Project Management/Subject Matter Experts/Additional Resources	$1,486.6	* Project/Program management resources required to manage the GDAR program as well as business and IT Subject Matter Experts required for GDAR requirements analysis, Systems design sessions, testing, and implementation of GDAR from January-December.
Total	**$7,923.3**	
		2006 URICDA
Requirements Analysis	$58.7	* Joint requirements analysis, validation, and project roadmapping sessions between Enbridge and Service provider for NGEIR implementation.
Tool Development	$284.2	Tool(s) designed and developed to automate (where possible) business process changes required for NGEIR implementation and augment the manual solution.
Business Process Changes	$44.6	Design, documentation, and implementation of new business processes required to implement NGEIR.
NGEIR Cutover	$1.7	Effort required for setting up and putting the NGEIR tool in production for use.
Project Management/Subject Matter Experts/Additional Resources	$91.3	Project/Program management resources required to manage the NGEIR program, Business Subject Matter experts for requirements, design, and implementation.
Total	**$480.5**	

Ontario Energy Board
FILE No. EB-2006-0034
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DATE February 2, 2007
08/99

K5.2

Table 1
GDAR Cost Breakdown

Scope Item	Capital Costs (a)	Annual O&M Costs (b)	In-Service Date (c)
1. Implement EBT standards	$7.0 million	$40,000	January, 2007
2. ABC service for Large Volume	$2.5 million	$0	January, 2007
3. Bill-Ready Service	$8.7 million	$460,000	January, 2008
Total	$18.2 million	$500,000	

Consistent with the costs approved by the Board in the RP-2003-0063 Decision, these incremental costs are required for regulatory compliance and recovery is not contingent on Union demonstrating that any benefits outweigh the costs.

As indicated in the Board's November 15, 2005 Decision, all capital and operating costs prudently incurred to implement GDAR should be recovered from customers, and specifically from those customer classes that benefit from the implementation of GDAR. The purpose of GDAR was to improve retail natural gas competition in Ontario. Therefore, the costs to implement the Rule should be paid for by those who stand to benefit from the Rule.

Union's two-year implementation plan, which is consistent with the Board's November 15th Decision, means that final GDAR compliance will be achieved in stages. As shown in Table 1, the EBT standards and ABC service for large volume customers will come

Ontario Energy
Board

Commission de l'Énergie
de l'Ontario

EB-2006-0021

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

AND IN THE MATTER OF a generic proceeding initiated by the Ontario Energy Board to address a number of current and common issues related to demand side management activities for natural gas utilities.

BEFORE: Pamela Nowina
Presiding Member and Vice Chair

Paul Vlahos
Member

Ken Quesnelle
Member

DECISION WITH REASONS

August 25, 2006

Ontario Energy Board
FILE No. EB-2006-0034
EXHIBIT No. K5.3
DATE February 2, 2007
page 43 only
08/99

How should existing or future carbon dioxide offset credits be dealt with in DSM plans and programs, if at all? (Issue 11.2)

The Board was presented with a partial agreement on this issue. All intervenors agreed as follows:

> "Until the rules are known, a deferral account should be established for each Utility and any dollar amounts representing proceeds from the sale or other dealings in credits should be credited to that account".

The utilities submitted that until the rules of carbon dioxide offset credits are known, the Board should not make any determination on this issue.

The Board accepts the argument by certain intervenors that there is no harm in ordering a deferral account to capture any future carbon dioxide offset credits. While the matter could wait until the resolution, if any, of the carbon dioxide offset credits matter, the utilities did not present convincing arguments to counter the no harm proposition advanced by many intervenors. The Board is generally reluctant to authorize the establishment of deferral accounts without a more concrete and immediate need. However since this matter is within the scope of DSM, there is an opportunity to deal with it now without the need for further processes. Therefore the Board concludes that the establishment of a deferral account would be a reasonable approach in the circumstances, and so orders.

Should free riders for custom projects be determined on a portfolio average or on a project basis? (Issue 12.1)

There was no settlement (complete or partial) on this issue.

The utilities proposed that the free ridership rate should be determined on a portfolio average basis. The single free ridership rate would apply across a number of technologies and a number of sectors. The utilities proposed a free ridership rate of 30%.

K6.1

Junk Keeps Defying Gravity

If history is any guide, low-rated bonds and loans should be tanking. Here's why they're not

BY JANE SASSEEN

FOR DECADES THE JUNK-bond market has followed a pattern that's about as regular as spring following winter. Two to four years after a new wave of bonds hits the market, defaults on those bonds surge.

This time, the pattern isn't holding. Given the huge runup in junk debt that began in 2003, many investors figured defaults would spike last year and began raising hundreds of millions for new distressed-debt funds to take advantage of the wreckage.

But a funny thing happened on the way to the meltdown: According to Moody's Investors Service, junk-bond defaults actually fell in 2006 for the fifth straight year, to 1.7%—well below the long-term average of 5%. The story is the same in the booming leveraged-loan market, which, thanks to more flexible borrowing terms, has become a favorite of the private equity firms raising billions for leveraged buyouts and the hedge funds that buy most of that debt. By the end of 2006, leveraged-loan defaults slid below 1%, an all-time low.

While many investors expect defaults to tick up this year, they've given up trying to call the turn. "They've simply been wrong too long," says Steven Miller, the managing director of Standard & Poor's LCD unit, which tracks the leveraged-loan market and is, like *BusinessWeek*, a unit of The McGraw-Hill Companies.

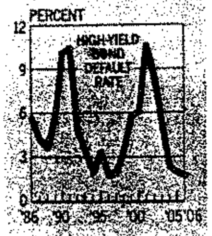
Some private equity players see a major structural shift at play: Greater liquidity across the capital markets and the explosion of sophisticated financial instruments, they say, are reducing the level of risk permanently. But others say the cycle is just being delayed, possibly leading to a harsher crash when it turns. "The big question is whether the excess money is simply giving weak companies all the rope they need to hang themselves," says David T. Hamilton, Moody's head of credit default research.

To see why some are worried, consider the record amounts of risky debt that have flooded the market in recent years. Start with junk bonds: New issuance has soared from $62 billion in 2002 to an average of $127 billion annually over the last four years. And that market has been dwarfed by the rise of leveraged loans, the higher-yielding bank loans that hedge funds and other investors are snapping up. Since 2002, the issuance of leveraged loans has more than tripled, to $480 billion last year, according to LCD.

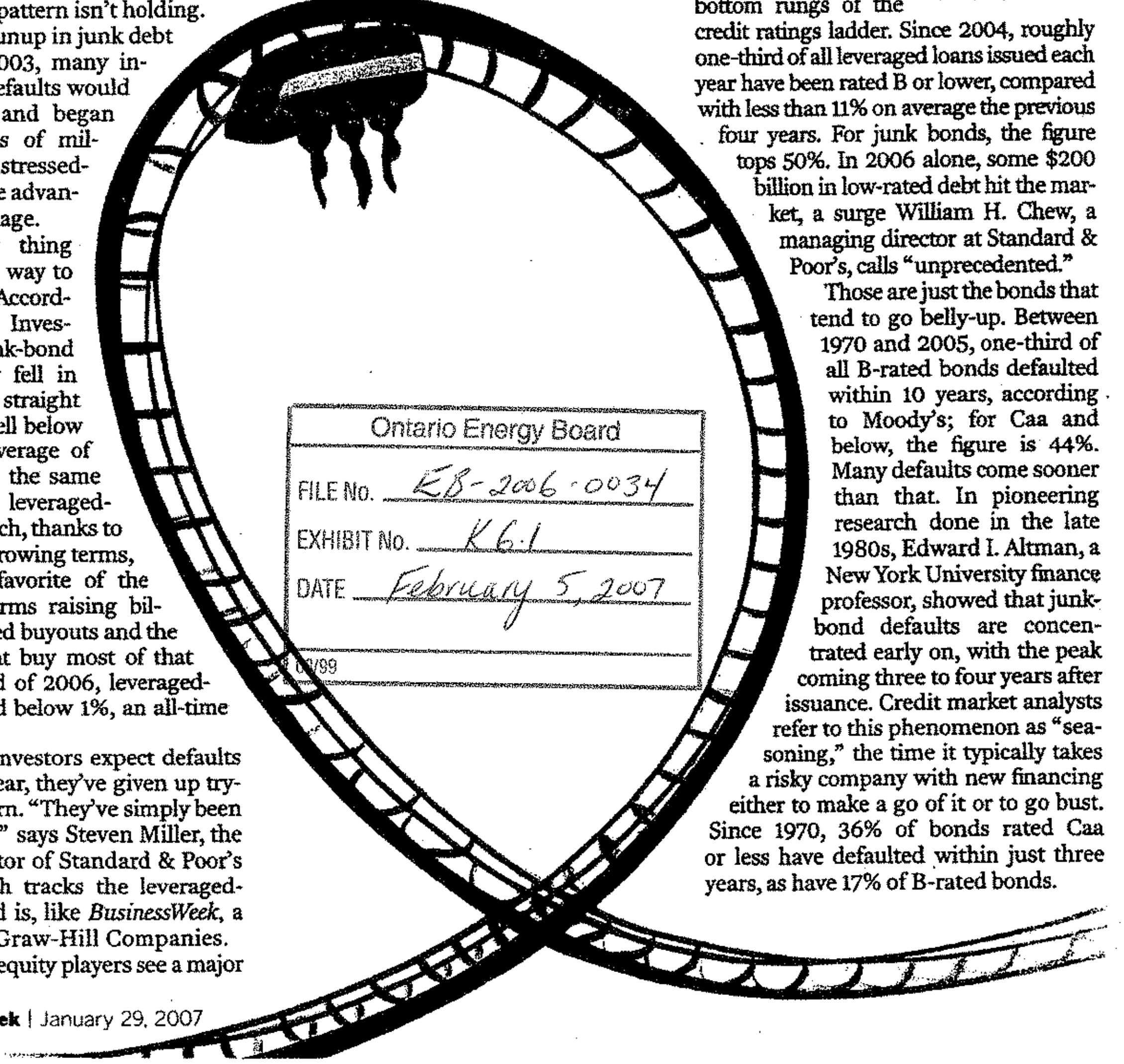
It's not just the quantity of loans that's worrisome—it's also the quality. Much of the debt is rated B or Caa and below, the bottom rungs of the credit ratings ladder. Since 2004, roughly one-third of all leveraged loans issued each year have been rated B or lower, compared with less than 11% on average the previous four years. For junk bonds, the figure tops 50%. In 2006 alone, some $200 billion in low-rated debt hit the market, a surge William H. Chew, a managing director at Standard & Poor's, calls "unprecedented."

Those are just the bonds that tend to go belly-up. Between 1970 and 2005, one-third of all B-rated bonds defaulted within 10 years, according to Moody's; for Caa and below, the figure is 44%. Many defaults come sooner than that. In pioneering research done in the late 1980s, Edward I. Altman, a New York University finance professor, showed that junk-bond defaults are concentrated early on, with the peak coming three to four years after issuance. Credit market analysts refer to this phenomenon as "seasoning," the time it typically takes a risky company with new financing either to make a go of it or to go bust. Since 1970, 36% of bonds rated Caa or less have defaulted within just three years, as have 17% of B-rated bonds.

NOWHERE TO GO BUT UP?



Data: Moody's Investors Service



Ontario Energy Board
FILE No. EB-2006-0034
EXHIBIT No. K6.1
DATE February 5, 2007
08/99

But for now, that isn't happening, and the surge in LBO-fueled debt is likely to continue in 2007 as well. Interest rates remain astonishingly low. In 2003 junk-rated debt typically sold for 5 to 8 percentage points above the yield of the 10-year Treasury bond; that spread has since dropped to 3.4 points. "More and more people are buying very speculative debt, at pricing that just doesn't justify the risk," says Chew.

DEEPER POOLS

ALL OF WHICH LEADS to an obvious question: Why haven't defaults begun to kick up? Analysts cite a host of reasons, starting with the relatively strong economy and the recent muscle in profits. But the biggest factors are the enormous amount of money sloshing around and the changing structure of the debt market. Foreign investors are shipping gobs of cash into the U.S. At the same time, there has been an explosion of hedge funds, distressed debt traders, and others eager to buy junk-rated debt for the higher yields it offers, much of it chopped up and resold in other sophisticated financial instruments such as collateralized loan obligations. Together, these factors have combined to create unheard-of pools of liquidity. Not only has that helped keep a lid on interest rates—holding debt payments down—it has also made funding readily available even for struggling companies.

There's another reason, too: easy borrowing terms. Restrictions and stipulations based on the financial health of the debtor are practically nonexistent these days, in both exotic leveraged loans and ordinary corporate bonds. Historically, when borrowers have violated such basic rules, they've been forced into default. Now, says Martin S. Fridson, a high-yield bond market strategist who runs the New York-based firm FridsonVision, the restrictions "have been so watered down, there's nothing left to trip."

Fridson, like Altman, believes the pain is simply being put off and defaults will return to historic patterns. Both predict a small climb this year and a sharper rise in 2008. And they say the level and severity of defaults may be worse when they finally hit, precisely because weak players are continuing to pile on new debt. Altman believes defaults could eventually approach the 10% rates seen in the early 1990s, in the wake of the last LBO boom. "If companies can keep getting money, they will," says Fridson. "But a lot of it is going to keep companies alive that really should not be." ■

ILLUSTRATION BY JON KRAUSE; CHART BY ALBERTO MENA/BW

K6.2

PRICING SUPPLEMENT NO. 2 DATED DECEMBER 14, 2006
(To a Prospectus dated February 14, 2006)

ENBRIDGE

ENBRIDGE GAS DISTRIBUTION INC.

Medium Term Notes
(Unsecured)

Terms of Issue

Principal Amount:	$175,000,000	Issue Price:	$99.958
Delivery Date:	December 19, 2006	Maturity Date:	December 17, 2021
Interest Rate:	4.77%	Interest Payment Date(s):	December 17 and June 17 commencing June 17, 2007
Yield to Maturity:	4.774%		

Redemption Provisions: The Medium Term Notes issued hereunder are redeemable prior to maturity, in whole or in part from time to time, at the option of the Corporation at a price equal to the Canada Yield Price on the business day next preceding the date on which notice of such redemption is given.

Agent(s):	RBC Dominion Securities Inc. BMO Nesbitt Burns Inc. CIBC World Markets Inc. HSBC Securities (Canada) Inc. National Bank Financial Inc. Scotia Capital Inc. TD Securities Inc.	Commission Rate:	0.45%
		CUSIP/ISIN Number:	CA29290ZAF77
		Registrar and Paying Agent:	Canadian Imperial Bank of Commerce
		Trustee:	CIBC Mellon Trust Company
Net Proceeds:	$174,139,000		

Documents Incorporated by Reference

The Prospectus dated February 14, 2006 into which this Pricing Supplement is deemed to be incorporated by reference also incorporates by reference certain other named disclosure documents of Enbridge Gas Distribution Inc., as follows:

(a) Consolidated comparative financial statements of the Corporation for the 12 month period ended December 31, 2005 and the auditors' report thereon;

(b) Management's discussion and analysis of financial condition and results of operations for the 12 month period ended December 31, 2005;

(c) Annual Information Form of the Corporation dated February 26, 2006 for the year ended December 31, 2005;

(d) Consolidated comparative interim financial statements (unaudited) of the Corporation for the nine-month period ended September 30, 2006; and

Ontario Energy Board

FILE No. EB-2006-0034

EXHIBIT No. K6.2

DATE February 5, 2007

08/99

EB-2006-0034

ONTARIO ENERGY BOARD

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 Enbridge Gas Distribution Inc. for an order or orders approving or fixing just and reasonable rates and other charges for the sale, distribution, transmission and storage of gas commencing January 1, 2007.

CROSS-EXAMINATION REFERENCE BOOK on behalf of POLLUTION PROBE

February 5, 2007

KLIPPENSTEINS
Barristers & Solicitors
160 John St., 3rd Floor
Toronto ON M5V 2E5

Murray Klippenstein
Basil Alexander
Tel: (416) 598-0288
Fax: (416) 598-9520

Counsel for Pollution Probe

INDEX

BOARD STAFF INTERROGATORY #25

INTERROGATORY

Ref: D1/T8/S1

Issue Number: 3.3
Issue: Is the Company's proposed fuel switching program appropriate?

EGD has requested an amount of $5.0 million in new initiatives aimed at promoting fuel switching activities. Please provide a breakdown of costs and the activities associated with each of the cost components.

a) How many conversions will this new initiative achieve in each of the first five years of its implementation?

b) Please provide the impact of this initiative on the distribution revenue during the first five years of its implementation?

c) Has EGD embarked on any similar initiatives before? If "Yes", please provide details of these prior initiative including volumetric and revenue impacts.

d) Has the Company performed a cost/benefit analysis of this initiative? If "Yes", please provide a report of this study. If "Not", please prepare and provide a detailed cost/benefit analysis.

e) As part of this initiative, the Company plans to raise awareness of natural gas and educate consumers on its benefits versus other alternate energy sources. Has EGD considered partnering with other vendors or Union Gas on this initiative to realise scale economies or share costs? Please provide details on any partnership initiatives including cost sharing and potential benefits. If EGD has not entered into any partnership, please provide reasons for not partnering on a generic initiative.

Witnesses: S. Clinesmith
P. Green
N. Ryckman
P. Squires

RESPONSE

A breakdown of costs and activities associated with these initiatives is included in Table 1 of this response.

a) Please refer to Table 1, Column 3 for the participants that will result in 2007.

b) Please refer to Table 1, Column 7.

c) In 2006, the Company's planned fuel switching initiatives were also imbedded in the Market Development portfolio. The financial impact of this 2006 portfolio is summarized below. Please note this information was previously filed as EB-2005-0001, Exhibit I, Tab 5, Schedule 41, as corrected 2005-09-07.

Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7
	Volume (million m3)	Revenue ($million)	O&M Cost ($million)	Measure Life NPV ($million)	TRC ($million)	SCT ($million)
Residential Market	29.5	2.2	4.7	1.9	43.5	55.7
Business Market	12.4	0.5	1.1	1.0	20.3	28.4
Total Market Development	41.9	2.7	5.8	2.9	63.8	84.1

d) Please refer to Table1, Column 8.

e) Enbridge Gas Distribution has considered partnering with vendors and Union Gas on this initiative to realize scale economies and/or sharing of costs. At this time, no detailed plans are available. Opportunities to reach consumers with a positive, common message about the benefits of natural gas for specific end-use applications will be explored.

Witnesses: S. Clinesmith
P. Green
N. Ryckman
P. Squires

Witnesses: S. Clinesmith
P. Green
N. Ryckman
P. Squires

Table 1

2007 Regulatory Budget

	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 1
	RESIDENTIAL MARKET	Vol (10^6 m^3)	Number of Participants	Life	Program Costs ($)	Incremental Cost per Participant	5 Year Distribution Revenue ($m)	Life NPV ($m)	TRC ($m)	SCT ($m)
1	High Efficiency Furnace	6.49	3,174	18	108,000	800	3.70	2.31	22.95	25.0
2	ECM	0.33	5,000	18	-	550	0.12	0.19	(0.54)	(0.3
3	Mid Efficiency Furnace	0.30	123	18	19,850	400	0.17	0.11	1.11	1.21
4	Fireplace	1.77	5,303	12	170,690	700	0.68	0.61	(6.12)	(6.2
5	Grill/BBQ	0.07	1,477	12	20,200	250	0.03	0.01	(0.18)	(0.1
6	Range/Dryer/Front Load Axis Washer	1.26	12,966	12	30,300	300	0.48	0.49	0.03	0.2
7	Low Income (WH)-fuel switching	0.78	1,150	9	925,000	800	0.38	(0.56)	0.38	0.5
8	Interior Constr. Heat Res New Cons*	10.60	18,644	1	123,742	350	1.40	0.80	5.19	5.4
9	Interior Constr. Heat Small Comm*	0.37	107	1	17,916	350	0.02	0.00	0.35	0.3
10	Residential Fuel Switching (Water Heating)	1.03	1,518	9	358,000	600	0.47	(0.06)	1.79	1.9
11	Water Heating	0.99	2,500	9	49,100	600	0.39	0.26	1.49	1.6
12	Outdoor Living/Garage heating/Pool Heating	0.33	550	12	170,690	700	0.12	0.04	(1.11)	(1.3
13	EnergyLinkTM	8.00	22,933	12	1,036,300	466	3.04	2.06	1.30	1.9
		32.31	75,445		3,029,788		10.99	6.26	26.67	30.3
14							Less Overhead	(2.49)	(2.49)	(2.4
15							Net Benefits	3.77	24.18	27.8
	BUSINESS MARKET									
16	Multi - Family Housing	3.75	18	20	180,823	350,000	0.80	1.17	11.75	12.7
17	Forklift Conversion	1.26	139	15	40,600	15,000	0.26	0.33	5.53	5.6
18	Commercial Construction Heaters*	7.00	175	1	20,000	1,600	0.46	0.28	7.02	7.1
19	Institutional/Commercial/Industrial	0.52	1,000	20	20,000	1,000	0.15	0.24	1.52	1.6
20	Small Com'l Business Partners	1.24	55	15	36,702	2,000	0.32	0.38	5.20	5.5
21	Small Com'l Load Plus	1.96	700	15	87,264	2,500	0.48	0.60	6.46	6.9
22	Small Com'l Additions/NonComs	1.92	180	15	87,824	5,000	0.52	0.43	6.44	7.0
		17.65	2,267		473,213		2.99	3.42	43.92	46.8
23							Less Overhead	(1.68)	(1.68)	(1.6
24							Net Benefits	1.74	42.24	45.1
25							**Total Net Benefits**	**5.51**	**66.42**	**72.9**

* Volumes are fully effective in the 1st year: distribution revenue, NPV, TRC and SCT based on 1 year only.

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4

FUEL SWITCHING AND ENBRIDGE GAS DISTRIBUTION

FOR ENBRIDGE GAS LIMITED

By
SeeLine Group Inc.
416-703-8695

February 2006

1.0 INTRODUCTION

As part of its support for Enbridge Gas Distribution (EGD) marketing efforts, SeeLine Group Inc (SLG) undertook an assessment of the proposed electric fuel switching program. The focus of the analysis was the determination of the Total Resource Cost Test (TRC) for the proposed electricity to gas fuel switching technologies. These technologies include space heating, water heating, cooking and clothes drying.

2.0 APPROACH

SLG conducted two analyses for this study. The first analysis used technology and program input assumptions provided by Enbridge (Fuel_Switching_Option 2 Master_may25.xls). The second analysis used some of the input assumptions supplied by Enbridge; however, electricity usage data for clothes dryers, ranges and water heaters, was supplemented by information currently available from the Ontario Energy Board.

Both TRC analyses were conducted using the benefit and cost definitions and structures as approved by the Ontario Energy Board where the cost is defined as the increased societal cost of natural gas (as expressed by the avoided costs), the incremental equipment cost and the associated utility program support costs. The benefits are the avoided resource costs associated with a reduction in electricity use.

The TRC assessments were conducted using SLG's SeeTool™ TRC calculator. This tool and approach replicates both the DSStrategist™ model used in the past by Enbridge and the common approach used by electric utilities in Ontario currently undertaking Conservation and Demand Management TRC planning and analysis exercises.

Electricity avoided costs used in the analysis are those provided by the Ontario Energy Board. Avoided costs are expressed in eight costing periods for energy (winter peak, winter mid-peak, winter off-peak, summer peak, summer mid-peak, summer off peak, shoulder peak and shoulder off peak) and one (summer) for peak (demand). As such, all electricity savings values must also be defined in the same manner.

In absence of gas costs used to evaluate system expansion projects, the company's DSM avoided gas costs were used for this analysis. These costs were used for the EBO 2005-0001 rate case evidence and provide a good proxy for examining fuel switching programs.

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2.0 RESULTS

Results from the first phase of this analysis are summarized in the tables below. Table 1a provides a summary of the proposed fuel switching program using the lower equipment life values for each technology.

Table 1a. Summary of TRC Results using Enbridge Data and Lower Equipment Life Assumptions

Program Results with Lower Equipment Life Assumptions
Total Resource Net Benefits
(shown in 2006 $'s)

	2006	2007	2008	2009	2010	Total
Furnaces (15 yrs)	$38,348,134	$ 49,310,597	$45,181,049	$29,497,987	$32,477,881	$194,815,647
Ranges (14 yrs)	$ 3,630,417	$ 4,594,486	$ 4,224,016	$ 2,831,876	$ 3,277,971	$ 18,558,766
Dryers (11 yrs)	$ 7,998,805	$ 10,638,713	$ 9,765,085	$ 6,255,385	$ 7,020,153	$ 41,698,142
Water Heaters (10 yrs)	$11,461,554	$ 35,878,424	$32,873,762	$21,815,245	$23,701,290	$125,530,276
Program Costs*	$ (3,059,729)					$ (3,059,729)
Total	**$58,381,187**	**$100,424,227**	**$92,085,920**	**$60,202,502**	**$66,479,306**	**$377,553,142**

* Marketing/Administration/Promotion Costs

Based on above results, the fuel switching program would provide positive net benefits for each year and technology as specified by the program assumptions. The total TRC net benefits for the full five years of the program are $377,553,142 (in 2006 dollars).

It should be noted that these and other TRC test results, do not include the $305,972,900 in incentive costs. These costs are merely transfer payments between the utility and the participant and therefore cancel each other out.

Table 1b. Summary of TRC Results using Enbridge Data and Higher Equipment Life Assumptions

Program Results with Higher Equipment Life Assumptions
Total Resource Net Benefits
(shown in 2006 $'s)

	2006	2007	2008	2009	2010	Total
Furnaces (17 yrs)	$ 44,949,956	$ 57,878,105	$ 53,031,066	$ 34,576,213	$ 38,099,274	$ 228,534,613
Ranges (15 yrs)	$ 4,307,348	$ 5,541,070	$ 5,095,007	$ 3,362,696	$ 3,940,171	$ 22,246,293
Dryers (13 yrs)	$ 9,925,804	$ 13,315,623	$ 12,248,091	$ 7,765,907	$ 8,758,977	$ 52,014,403
Water Heaters (13 yrs)	$ 15,145,847	$ 47,437,924	$ 43,465,204	$ 28,566,563	$ 31,331,634	$ 165,946,972
Program Costs*	$ (3,059,729)					$ (3,059,729)
Total	**$ 71,271,032**	**$ 124,174,730**	**$ 113,841,376**	**$ 74,273,388**	**$ 82,132,066**	**$ 465,682,552**

* Marketing/Administration/Promotion Costs

As would be expected, the higher equipment life assumptions yield greater TRC net benefits as shown in Table 1b. This is largely due to the longer lifecycle of

Written Submission

Enbridge Gas Distribution to the Ontario Power Authority in the matter of the province's energy supply mix

August 26, 2005

Introduction: Enbridge Gas Distribution ("Enbridge") is pleased to provide this response to the Call for Written Submissions issued by the Ontario Power Authority in the matter of the province's energy supply mix. The following considerations reflect Enbridge's 157-year history of anticipating and adapting to changing energy circumstances in Ontario, and meeting the changing needs of generations of customers.

Natural gas - Part of a diverse energy portfolio: Ontario's natural gas sector is well-positioned to play its part in realizing the government's stated goal of a diverse supply of competitively priced power within a conservation culture:

- ***Sufficient supply:*** There will be enough natural gas supply to meet future needs. Natural Resources Canada has calculated total remaining natural gas reserves in North America alone at 75 times current consumption levels. In addition, significant additional reserves have been and are being identified.

- ***Fair and reasonable prices:*** Natural gas is and will remain an economic energy choice. Based on the experience of Enbridge's own customers in recent years, natural gas has been on average about 39% less expensive than electricity and 20% less expensive than oil.

- ***Environmental benefits:*** Environment Canada has noted that natural gas-fired power generation emits the lowest level of greenhouse gases among all fossil fuels. In addition, an independent study released by the Ministry of Energy in April 2005 concluded that a combination of nuclear and natural gas-generated electricity was the lowest-cost energy scenario in terms of money, public health and the environment.

- ***Conservation culture:*** The natural gas sector has initiated a number of energy efficiency programs to help customers reduce the amount of natural gas they use. Programs implemented by Enbridge between 1995 and 2004 alone reduced consumption by the equivalent of the gas used by 620,000 homes in one year. Those same programs reduced carbon dioxide emissions by the equivalent of removing 750,000 cars from the road for one year.

- ***Advancing stated public policy objectives:*** As noted above, natural gas can advance the Ministry's stated desire for diversity of supply. It also advances the findings of an Ontario Energy Board ("OEB") report issued in March 2005, which recognized the important and growing role of natural gas and natural gas infrastructure in the province's energy system.

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Fuel switching - The focus of this submission: There are a number of ways in which natural gas can contribute to the achievement of the province's stated energy needs and objectives. One way is through large scale electricity generation. Another is through distributed energy. Still another is through energy efficiency models that provide demand side management and other programs tailored to particular classes of customers.

The focus of this submission, however, is on another aspect of the natural gas component of a diverse energy mix. This aspect - fuel switching – entails the switching of customers from electric appliances to natural gas appliances that can perform the same chores, often in a more effective and cost-efficient way.

Fuel switching - The plan and the benefits: The remainder of this submission discusses a five-year plan for the switching of 1,043,425 furnaces, water heaters, ranges and dryers from electricity to natural gas. Under this initiative, the benefits to Ontario would include:

- ***Reduced electricity demand:*** Peak load electricity demand would be reduced by 1,490 megawatts.

- ***Avoided generation costs:*** The move to natural gas-fired appliances would realize avoided electricity generation costs of $1.146 billion.

- ***Decreased greenhouse gas emissions:*** The switch from electric to natural gas appliances would lower greenhouse gas emissions by 2.5 million tonnes.

Fuel switching - The potential for quick 'wins': One of the key attributes of the fuel switching initiative is the speed with which the benefits could be realized. This is due, in part, to the fact that the natural gas infrastructure and technology to implement such a program are already in place. There follow three areas or quick 'wins' that demonstrate the benefits that can be achieved for Ontario in short order, using existing technology, and building on current or reinforced infrastructure.

- ***Space heating:*** Electrical residential space heating can account for up to 60% of residential electricity use. Switching the space heating source from electricity to natural gas furnaces could save $1.1 billion in avoided generation costs.

- ***Water heating:*** Heating water electrically can total up to 20% of residential electricity use. Switching to natural gas tankless water heaters can increase energy efficiency and lower customer costs

- ***Helping low income residents:*** Approximately 14% of Ontario residents live at or near the poverty line. More than 50% of them use electric water heaters, which cost more to operate than natural gas heaters. Thus, people who can least afford it are paying more to heat their water than they have to. Switching their water heaters from electricity to natural gas has the potential to save this group some $146 million in avoided generation costs.

Fuel switching - The role of incentives: One way to encourage the implementation of any fuel switching initiative is to make the prospect attractive to customers. Here, as elsewhere in the economy, retail prices can influence consumer choices and buying decisions. The cost of purchasing new natural gas appliances, before the end of the useful life of existing electricity appliance stock, can be an impediment to change with many customers. This fact alone can deter consumers from pursuing the natural gas option, even though they can realize significant cost savings over the life of those natural gas appliances.

One way to encourage consumers to choose the natural gas option, and to realize the potential benefits for the province, is through the use of direct-to-ratepayer incentives for purchasing natural gas appliances. Such incentives could be provided in one of two ways. The first is by the provincial government itself. The second is through the regulatory process in which local utilities would factor such incentives into their rate structure, build cost recovery plans into their rate submissions, and seek approval of those submissions through the OEB in the normal course.

Either way, if direct-to-ratepayer incentives were provided for 50% of the purchase price of switching to natural gas appliances, and as the Fuel Switching – Summary Results document appended to this submission indicate, Ontario would still realize net avoided generation costs of $617 million under the proposed five-year fuel switching program.

Fuel switching - Other considerations: Enbridge recognizes that other considerations are associated with the proposed fuel switching initiative. One is that the cost of the related system expansion would fall within natural gas utility rates. Another is that the demand for natural gas would increase. Analysis suggests, however, that the increased use would equal just 0.2% of total North American demand. A third factor is the proposed five-year timetable itself. Enbridge believes that this schedule, while aggressive, is achievable using current technology and building on current infrastructure.

In conclusion – Natural gas, fuel switching, and the benefits to Ontario: By way of summary, and in support of its proposed five-year fuel switching initiative from electric to natural gas appliances, Enbridge Gas Distribution submits that:

- **Natural gas can do its part:** Natural gas is well-equipped to play a significant role within Ontario's changing energy mix. It is plentiful, economical, and environmentally sound.

- **Fuel switching is a viable and achievable initiative:** Fuel switching from electric to natural gas appliances - an initiative that is being pursued elsewhere - can be achieved at low risk through existing infrastructure and technology.

- **Ontario will benefit:** The fuel switching initiative will, among other things, address the government's stated policy objectives, reduce electricity demand, avoid generation costs and lower greenhouse gas emissions.

Fuel Switching– Summary Results

	Over 5 years
Megawatts Saved (Diversified Demand)	1,490
Net GHG Emissions Reduced	2.5 million tonnes
Cost of 1,490 MW NG Fired Generation	$1.146 billion
Incentive Cost (@ 50% of replacement)	$0.529 billion
Avoided Generation Cost	$0.617 billion
Ratio of NG Fired Generation Costs to Incentive	2 to 1
Total Electric Appliances switched	1,043,425
Furnaces	114,875
Water Heaters	279,200
Ranges	323,000
Dryers	326,350

Market Transformation Assumptions

Enbridge Gas Distribution Inc.			Market Penetration				
		5 Years		Existing Home		New Homes	
Residential Customers	1,525,000		Appliance	Current	Proposed	Current	Proposed
New Home additions	40,000	200,000	Furnaces	90%	93%	98%	100%
System Expansion/year	4,500	22,500	Water Heaters	86%	93%	91%	96%
Infill Customers/year	5,000	25,000	Ranges	24%	34%	24%	34%
			Dryers	30%	46%	30%	40%
System Expansion	35% electricity / 65% oil						
Infill Customers	35% electricity / 65% oil						
Heating only	35% electricity / 65% oil						

Union Gas			Market Penetration				
		5 Years		Existing Home		New Homes	
Residential Customers	1,200,000		Appliance	Current	Proposed	Current	Proposed
New Home additions	20,000	100,000	Furnaces	92%	95%	100%	100%
System Expansion/year	1,000	5,000	Water Heaters	85%	92%	86%	96%
Infill Customers/year	4,000	20,000	Ranges	19%	29%	19%	29%
			Dryers	21%	31%	21%	31%
System Expansion	50% electricity / 50% oil						
Infill Customers	50% electricity / 50% oil						
Heating only	50% electricity / 50% oil						

POLLUTION PROBE INTERROGATORY #3

INTERROGATORY

Ref: D1/T2S1 Attachment A

Issue Number: 3.2
Issue: Is the overall level of the 2007 Operation and Maintenance Budget appropriate?

With respect to each of the Opportunity Development Department's programmes, please provide each programme's forecast Total Resource Cost (TRC) Test net benefits. In addition, please provide the input assumptions used to calculate each programme's TRC Test net benefits.

RESPONSE

In the Company's response to Board Staff Interrogatory #25 (Exhibit I, Tab 1, Schedule 25) information on the Company's Market Development programs, including TRC calculations, was provided. The Company has not completed TRC calculations for any of its other activities. To provide additional clarity, the Company is able to provide the following:

A breakdown by department of the Opportunity Development Budget developed for the purposes of the Company's original application is shown in Table 1.

Table 2 contains a breakdown of the Residential and Business Market programs within the Market Development department and additional detail for the EnergyLink^{TM} program.

Witnesses: S. Clinesmith
P. Green
K. Lakatos-Hayward
P. Squires
N. Ryckman

Table 1

Opportunity Development Department Breakdown O&M	2005 Actual	2006 Bridge Year Estimate	2007 Test Year Budget
Market Development			
Salaries + Employee Expenses	967	1,160	1,703
Program Expenses	909	2,417	7,363
Sub Total	1,876	3,577	9,066
* *Energy Opportunities*			
Salaries + Employee Expenses	771	883	1,078
Program Expenses	623	294	1,431
Sub Total	1,394	1,177	2,509
* *Business Development & Strategy*			
Salaries + Employee Expenses	1,426	1,072	1,709
Program Expenses	1,294	595	1,324
Sub Total	2,720	1,667	3,033
Storage Operations			
Salaries + Employee Expenses	2,479	2,349	2,815
Maintenance & Operating Expenses	3,957	3,945	4,914
Sub Total	6,436	6,294	7,729
Energy Policy & Analysis			
Salaries + Employee Expenses	455	923	1,034
Operating Expenses	92	161	319
SLA's	4,338	2,500	2,625
Sub Total	4,885	3,584	3,978
Business Intelligence & Support			
Salaries + Employee Expenses	1,450	1,551	1,880
Operating Expenses	560	508	727
Sub Total	2,010	2,059	2,607
Opportunity Development Administration			
Salaries + Employee Expenses	698	761	766
Operating Expenses	12	89	126
Sub Total	710	850	892
Summary			
Salaries + Employee Expenses	8,246	8,699	10,985
Program & Operating Expenses	7,447	8,009	16,204
SLA	4,338	2,500	2,625
NGV	878	1,041	1,049
Total Expenses	20,909	20,249	30,863

Witnesses: S. Clinesmith
P. Green
K. Lakatos-Hayward
P. Squires
N. Ryckman

Table 2

MARKET DEVELOPMENT FIXED AND VARIABLE COSTS		Fixed ($000,000)	Variable Incentives ($000,000)	Total ($000,000)
Residential	**Initiative**			
	High Efficiency Furnace	$0.022	$0.086	$0.108
	Mid Efficiency Furnace	$0.000	$0.020	$0.020
	Fireplace	$0.171	$0.000	$0.171
	Grill/BBQ	$0.020	$0.000	$0.020
	Range/Dryer/Front Load Axis Washer	$0.030	$0.000	$0.030
	Low Income (WH)	$0.034	$0.891	$0.925
	Interior Constr. Heat Res New Cons	$0.124	$0.000	$0.124
	Interior Constr. Heat Small Comm	$0.018	$0.000	$0.018
	Residential Fuel Switching (Water Heating)	$0.072	$0.286	$0.358
	ECM	$0.000	$0.000	$0.000
	Water Heating	$0.000	$0.049	$0.049
	Outdoor Living/Garage heating/Pool Heating	$0.171	$0.000	$0.171
	EnergyLink™ (See Note 1 For Assumptions)	$0.445	$0.592	$1.036
	Residential Overheads	$2.487	$0.000	$2.487
		$3.592	$1.925	**$5.516**
Business Markets	**Initiative**			
	Multi-Family Housing	$0.181	$0.000	$0.181
	Forklift Conversion	$0.007	$0.034	$0.041
	Commercial Construction Heaters	$0.020	$0.000	$0.020
	Institutional/Comm/Industrial	$0.020	$0.000	$0.020
	Small Comm. Business Partners	$0.016	$0.020	$0.037
	Small Comm. Load Plus	$0.010	$0.077	$0.087
	Small Comm. Additions/Noncoms	$0.024	$0.064	$0.088
	Business Markets Overheads	$1.680	$0.000	$1.679
Total Bus. Markets		$1.958	$0.195	**$2.152**
Marketing Admin		$0.358	$0.000	$0.358
		$0.358	$0.000	**$0.358**
Marketing Communications		$1.040	$0.000	$1.040
		$1.040	$0.000	**$1.040**
Market Development Total		**$6.949**	**$2.120**	**$9.067**

Note 1: 2007 EnergyLink Program Assumptions	Participants	Volumes (000 m^3)
Furnace	1,200	2,454
Water Heater	2,500	1,702
Dryer	6,483	726
Fireplace	5,303	1,771
Ranges	6,483	525
Lifestyle Products	700	777
ECM	262	48
Total	**22,931**	**8,003**

Witnesses: S. Clinesmith
P. Green
K. Lakatos-Hayward
P. Squires
N. Ryckman

Business Development & Strategy (BDS) Department

The following paragraphs and Table 3 provides descriptions of the primary initiatives and programs included in the Business Development & Strategy as filed Budgets.

The Energy Technology (ET) group which operates with the BDS department creates new opportunities for added and retained load initiatives, energy efficient technologies, and improved operational efficiencies by influencing and accelerating technology development in the market. These initiatives provide significant customer, environmental and Company benefits.

The planned technology development projects for 2007 cover all market sectors as well as distribution-related technology development projects. In 2007, ET will also focus on new customer segments like power generation, small scale distributed energy, natural gas cooling and BTU metering in multi-residential buildings.

As Enbridge continues to face an increasingly uncertain energy market in terms of price, market share and environmental pressures, technology development efforts become even more important. It is clear from the actions of the Provincial Government that the Province is determined to find cost effective, environmentally superior options to address the province's electricity supply issues, and that natural gas is part of the solution. To develop technology options that meet our customers' needs, the Company must play an active role in influencing technology development in North America.

Energy Technology professionals work with marketing personnel to help identify utilization technology projects that have a strategic market fit and also have a high expectation of success. Energy Technology also works with clients in Operations and Engineering to identify initiatives which enhance operational performance and efficiency, safety, and reliability.

In 2006, Energy Technology activities achieved a benefit: cost ratio of 2.1:1. A similar level of benefits is expected in 2007. Additionally, the Department is able to leverage $8 of external funding for technology development for every $1 of funds invested by the Company.

Witnesses: S. Clinesmith
P. Green
K. Lakatos-Hayward
P. Squires
N. Ryckman

Table 3

Energy Technology Projects

Initiative	Description
Ultrasonic Cased Pipe Inspection	Development of a long-range guided wave ultrasonic technology (UT) for inspection of cased pipe. The project involves adapting technology currently used for above-ground applications.
Service Abandonment Plug	Development of an elastomeric expansion plug and applicator device, which will be used to cease natural gas flow when performing a COAM ("cut-off at main") operation.
Keyhole Service Line Installation	Development of a process to install PE service lines through a keyhole, by a combination of sourcing and developing the necessary tools.
Gate valves	To evaluate the performance of a new NPS 4 Steel gate valve to provide an alternative product with reduced costs compared to the standard NPS 4 Steel gate valves. A pilot program is being conducted.
Remote corrosion monitoring	Develop a new methodology for remote corrosion monitoring equipment which is more efficient and has lower costs compared to the current manual corrosion monitoring methodology. A pilot program is being conducted.
Residential Cogeneration	Lab/field demonstration of residential cogeneration units. Deal with issues in Canadian market to ease entry for product manufacturers.
Building Recommissioning	Test and document discrete incremental improvements in operation and equipment of older buildings. Provide support through empirical test data.
Water Heating	Installation, testing and data collection of instantaneous boiler performance. Compare efficiency gains against baseline data collected with a traditional boiler/storage system.

Witnesses: S. Clinesmith
P. Green
K. Lakatos-Hayward
P. Squires
N. Ryckman

Initiative	Description
Roof Top Units & Make Up Air Units	Investigate actual efficiency of installed units.
Snow Melter	Development of a direct-contact boiler driven snow-melting system. For >10 MMBTU/hr localized municipal zone operation (i.e. semi-mobile units).
Powder Coat Furnace	High-temperature gas-fired infra-red furnace. Originally developed for plastic thermoforming to be assessed for powder-coating.
Multi-Res Showcase Building	Develop metering options and alternatives to position natural gas as an affordable option for vertical sub-divisions.
Direct Flame Impingement Furnaces	Commercialize open-flame furnaces for both ferrous and non-ferrous applications.
Gas Fryer Project	Beta-testing of a new commercial fryer. The fryer will have 10% improved efficiency and reduced oil consumption.
Pressure Cooker Project	Completing the Beta-testing of a new commercial pressure cooker. The cooker will have 20% improved efficiency and design improvements.
Gas Dryer Project	Development of how to guide pertaining to the fuel switching opportunities in the Gas dryer, multi-residential arena. The development project will include the measurement and performance benefits of makeup air systems as well as active and passive ventilation systems.
Thermal Remediation	Develop a process to perform remediation of food processing facilities.
Airplane Deicing	Beta testing of an Infra-red de-icing system for commercial aircraft.
Dishwasher/Warewasher	Developing a gas powered ware washer for the 200-300 seat restaurant market.

Witnesses: S. Clinesmith
P. Green
K. Lakatos-Hayward
P. Squires
N. Ryckman

Initiative	Description
High efficiency Broiler	Developing a high efficiency broiler.
Micro turbine demonstration	Verify performance for this technology in a field test at a commercial building site.
Ground Source Heat Pump	Assess efficiency and performance of specific units through field testing.
High efficiency heat recovery	Development of an enthalpy energy transfer membrane for Industrial boilers to recover energy through exhaust.
Organic Rankine Cycle generator as replacement for absorption	A study of absorption systems compared to "Organic Rankine Cycle" generator heat conversion technology for large Commercial combined heat & power.
Integrated Fireplace	Develop product to stage of commercialization.
Residential Absorption Heat Pump	Development of a high efficiency absorption heat pump for residential applications.

The Sustainable Energy group (SE) which operates within the BDS department provides strategic leadership to EGD in relation to Corporate Social Responsibility efforts. As the utility industry moves into a carbon-constrained future, the SE group also takes a lead role in tracking and reporting EGD's GHG emissions and develops action plans and targets for reduction of these emissions. SE also plays an active role in assessing renewable energy technologies as an effective means to help customers use energy more efficiently.

The SE group supports four key EGD program areas:

1) Environmental Technology Development

2) Climate Change and Emissions Reporting

3) Growth Initiatives

4) Corporate Social Responsibility (CSR)

Witnesses:
S. Clinesmith
P. Green
K. Lakatos-Hayward
P. Squires
N. Ryckman

Energy Opportunities Department

The Energy Opportunities department is advancing the markets for natural gas' continued adoption within the emerging sectors of distributed generation, district energy, and advanced energy technologies, such as stationary fuel cells. These initiatives strengthen the position of natural gas in the electricity sector as well as establish improved environmental performance in a rapidly evolving provincial energy sector.

The Distributed Energy (DE) group is responsible for developing and servicing all forms of gas-fired generation within the EGD franchise. The market ranges from small 30 kilowatt micro turbines to large 990 megawatt combined cycle facilities. These installations can vary in use from on-site backup generators to central merchant plants.

In 2007, EGDI will continue to service, support and facilitate gas-fired generation. Examples of development efforts intended for 2007 include:

- Commissioning of gas delivery to Goreway Station.
- Commencing of Portlands Energy Centre gas delivery project.
- Commencing of Thorold Cogen. L.P. gas delivery project.
- Supporting proponents participating in the gas generation projects (e.g. York region, Southwest Greater Toronto Area) identified in the Ontario Power Authority's (OPA) Integrated Power System Plan (IPSP).
- Servicing proponents participating in OPA's Phase II of Combined Heat & Power Request For proposal (CHP RFP Phase II)
- Facilitating proponents participating in the OPA's Clean Energy Standard Offer Program (CESOP) and other small generation projects.
- Facilitating the use of gas-fired generation in backup, demand response and peak-shaving operations.

In addition, the DE group continues to work with customers and potential customers to develop and improve services. Examples are the new ancillary services as tabled in the Natural Gas Electricity Interface Review (NGEIR) decisions which will be effective in 2007.

Witnesses: S. Clinesmith
P. Green
K. Lakatos-Hayward
P. Squires
N. Ryckman

For smaller scale generation, EGD works with business partners to reduce or eliminate barriers to the adoption of distributed generation, and assist customers in selecting solutions. The Company supports customers' needs through the provision of technical, analytical, regulatory and attachment support. For example, support is provided for the further development of Combined Heat Emergency Power (CHeP) projects.

The benefits from these efforts include supplying much needed power to the Toronto area, with a suite of ancillary services which will provide the tools for the power generators to address their load-balancing needs. The Company will also facilitate true distributed generation in congested areas within EGD's franchise area and this will provide benefits through greater flexibility and responsiveness to meet customers' energy needs. These benefits also include energy supply security, higher total energy efficiency, reduced electrical transmission loss and congestion, and reduced environmental emissions.

Fuel cell technologies are also addressed within the Energy Opportunities department. Large stationary fuel cells are a form of distributed generation; however, compared to combustion-based generation, the technology's unique environmental and technical attributes provide gas utilities with a means of embedding enhanced value in the electricity that is generated from fuel cells. The low environmental impact of electricity that is generated from natural gas fuel cells has similar characteristics to many renewable electricity supplies. The unparalleled efficiencies are a direct fit with the utility's advancement of energy efficiency, and adoption of the technology within Enbridge's franchise area will strengthen the company's base of embedded base-load technologies.

The 2007 fuel cell activities support the company's pilot plant development, which is being implemented at 500 Consumers Road in Toronto. Performance monitoring, reporting and verification activities have been budgeted to document the pilot plant's performance following its commissioning. To assist the company, and its customers, with future technology adoption, the Energy Opportunities Department will implement a communications plan and market transformation plan to advance the needed industry and government engagement that will establish supportive policies for this technology.

Specific technology development plans for 2007 include the establishment of the needed service/support infrastructure for the pilot plant and subsequent technology adoption. This includes a number of training programs for Company employees and third party service providers.

Witnesses: S. Clinesmith
P. Green
K. Lakatos-Hayward
P. Squires
N. Ryckman

The plant commissioning will result in expenses related to the maintenance of the pilot plant. These expenses have been budgeted within the Energy Opportunities department for 2007; however, once the plant's commissioning activities are complete and the plant moves to commercial acceptance (projected for Q1-2008), the maintenance expenses will be offset by the pilot plant revenues derived from the sale of the project's electricity.

The distributed energy market continues to evolve in Ontario. Both distributed generation and fuel cells can be embedded within a distributed energy system. In addition to the sector specific activities listed for distributed generation and fuel cells, Energy Opportunities will continue to engage industry stakeholders who are working to establish specific distributed energy investments in Enbridge's franchise area.

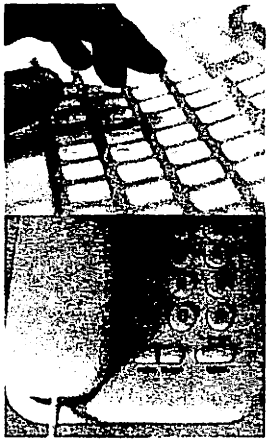
Witnesses:	S. Clinesmith
	P. Green
	K. Lakatos-Hayward
	P. Squires
	N. Ryckman

Welcome to EnergyLink,™ the new source for all your natural gas needs

EnergyLink™ is a new program brought to you by Enbridge Gas Distribution. It will help you locate qualified natural gas contractors in your area, as well as provide you with the most up-to-date information and links regarding natural gas products and services.

Your link to a one-stop referral system

When you contact EnergyLink™ (by internet or by phone) and indicate which natural gas service you require, EnergyLink™ will provide you with up to three referrals to qualified natural gas contractors in your area. It's that simple!



Your link to peace-of-mind

Only qualified natural gas contractors who have been pre-screened by Enbridge Gas Distribution can become approved EnergyLink™ contractors. When you see the EnergyLink™ logo, you can be assured they are fully qualified to install natural gas equipment and products.

Your link to easy access

Now it's easier to find a qualified natural gas contractor! Just go to **www.enbridge.com/energylink** and follow the links to the information you require. Or, if you would rather access EnergyLink™ by phone, just call **1-888-991-9001**, and a friendly customer service representative will help you.

Your link to quality

There is no more guesswork. If you've been referred to an Enbridge Gas Distribution approved EnergyLink™ contractor, you can be confident that they can install natural gas equipment and products.

EnergyLink™ from Enbridge Gas Distribution. Now choosing natural gas is not only one of the best decisions you can make - it's one of the easiest.

Introducing

Energy Link™

Your link to
natural gas
contractors
approved by
Enbridge Gas
Distribution

ENBRIDGE

Natural gas is one of the most efficient, versatile and clean energy sources available today. Once connected to natural gas, there is no end to the advantages it can bring to your life. Whether you simply want to lower your energy costs, or enjoy the benefits natural gas appliances and products can add to your home (such as instant-on fireplaces), becoming connected to natural gas is one of the best investments you'll ever make.

And now, with EnergyLink™, the decision to switch has been made even easier.

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www.enbridge.com/energylink
or 1-888-991-9001

ENBRIDGE

Finding a qualified natural gas contractor has just become easier

K6.4

EB-20006-0034

Before the Ontario Energy Board

Enbridge 2007 Test Year Rate Case

Cross Examination Materials filed by Green Energy Coalition

Ontario Energy Board

FILE No. EB-2006-0034

EXHIBIT No. K6.4

DATE February 5, 2007

08/99

Enbridge Gas Distribution
Operating and Maintenance Expense by Department
Calendar Year Ending December 31, 2006

Line No.	Particulars ($ 000's)	Estimate 2006
1	Finance	$ 12,362
2	Customer Care Service Charges (including CIS)	105,216
3	Customer Care Internal Costs	3,200
4	Provision for Uncollectibles	15,570
5	Regulatory Affairs	12,118
6	Law, Corporate Security & LR&PA	1,612
7	Operations	46,908
8	Information Technology	20,491
9	Opportunity Development (excluding DSM)	20,249
10	Human Resources (excluding benefits)	17,377
11	Benefits	21,301
12	Engineering	26,976
13	Public and Government Affairs	4,345
14	Non Departmental Expenses	4,127
15	Corporate Allocations (including direct costs)	24,761
16	Total	336,613
17	Capitalization (A&G)	(18,071)
18	Total Net Utility Operating and Maintenance Expense, Excluding DSM	318,542
19	Demand Side Management Programs (DSM)	18,914
20	Total Net Utility Operating and Maintenance Expense	$ 337,456

Notes:
1) Departmental O&M costs are net of capitalization, non-utility allocations and other utility adjustments.
2) LR&PA corresponds to Legal, Regulatory Affairs and Public Affairs Admin.

Witnesses: D. Kelly
T. Ladanyi
A. Urquhart

2

mid-1990's). Additional analytical support was required from other departments (i.e., Finance) that is now provided or augmented by departments in Enbridge Inc. (Corporate Controller Department), enabling further efficiencies to be gained. Services from the Senior Leadership, including the CEO, Group Vice President Gas Strategy & Corporate Development Department, as well as Treasury are also required to ensure that Enbridge Gas Distribution's strategic plan and financial long-range plan receives approval from the Board of Directors. This activity would be required on a stand alone basis and is not currently performed within Enbridge Gas Distribution.

2006 Budget Forecast

64. The 2006 Budget forecast of $18.5 million is comprised of the following: Market Development ($4.7 million); Sustainable Growth ($3.7 million); EOS and EI SLA contracts ($4.5 million); Business Support ($2.2 million); Energy Policy & Analysis ($1.0 million); OD Administration ($1.0 million); Strategic Planning ($0.2 million); and EI charges of ($1.2 million).

Table 1

Department Budget for 2006

	Col. 1 Item	Col.2 Amount ($millions)	
1	Salaries, Employee Training and Expenses	$	6.4
2	Program Cost	$	6.4
3	Gas Supply & Gas Control Agreements	$	4.5
4	Sub-Total	$	17.3
5	Cost charged by affiliates	$	1.2
6	Cost charged to affiliates	$	-
7	Total	$	18.5

Note: Excluding DSM, NGV and Gas Storage costs

Filed: 2006-08-25
EB-2006-0034
Exhibit D3
Tab 2
Schedule 2
Page 1 of 1

Enbridge Gas Distribution
Operating and Maintenance Expense by Department
Calendar Year Ending December 31, 2007

Line No.	Particulars ($ 000's)	Budget 2007
1	Finance	$ 12,492
2	Customer Care Service Charges (including CIS)	101,605
3	Customer Care Internal Costs	3,422
4	Provision for Uncollectibles	15,105
5	Regulatory Affairs	11,710
6	Law, Corporate Security & LR&PA	1,838
7	Operations	52,905
8	Information Technology	23,810
9	Opportunity Development (excluding DSM)	30,863
10	Human Resources (excluding benefits)	19,222
11	Benefits	23,040
12	Engineering	33,497
13	Public and Government Affairs	5,576
14	Non Departmental Expenses	4,953
15	Corporate Allocations (including direct costs)	22,886
16	Total	362,924
17	Capitalization (A&G)	(19,134)
18	Total Net Utility Operating and Maintenance Expense, Excluding DSM	343,790
19	Demand Side Management Programs (DSM)	20,332
20	Total Net Utility Operating and Maintenance Expense	$ 364,122

Notes:
1) Departmental O&M costs are net of capitalization, non-utility allocations and other utility adjustments.
2) LR&PA corresponds to Legal, Regulatory Affairs and Public Affairs Admin.

Witnesses: D. Kelly
T. Ladanyi
A. Urquhart

GREEN ENERGY COALITION INTERROGATORY #1

INTERROGATORY

Ref. D1/T8/S1

Issue Number 3.3

Issue: Is the proposed increase of $5.0 million in Market Development Initiatives related to promoting fuel switching activities appropriate?

i) Please provide any analyses or estimates of cost-effective potential, that the company has in regard to fuel switching.

ii) Please file copies of any presentations to the Enbridge Board or to external entities such as the OPA on fuel switching that the company has given in the last two years.

iii) Please indicate the amount of the existing market development budget that has been used specifically for fuel switching promotion in recent years and provide detail for those expenditures.

iv) Please break out the intended use of the $5 million and any portion of the existing Marketing budget that will also be used to promote fuel switching as between research, advertising, customer incentives etc. to the extent known at this time.

v) The company notes that water heating is a priority in the near term. How will the company address the higher first cost issue for different market sectors? What plans if any are being considered for tank rentals?

vi) Please discuss the short term and long term rate implications for existing customers of various types of fuel switched load including the impacts from the market development expenditures themselves.

vii) Please provide an analysis of the opportunity and costs for low income customer water tank fuel switching assuming 100% of incremental costs are being borne as a program cost of the utility and provide details of any alternative strategy that the company is considering to address this identified priority.

Witnesses: S. Clinesmith
P. Green
P. Squires

vii) Please detail any plans or plans being considered to utilize affiliates or a dealer network or similar approach to encourage fuel switching. How will the company address concerns of the HVAC industry about the need to avoid obtaining unfair competitive advantage for affiliates?

viii) In responding to Board Staff's request for a cost benefit/analysis, please ensure that an analysis of the societal benefits of fuel switching is included.

RESPONSE

i) The following table summarizes the fuel switching potential that could be realized in the Enbridge Gas Distribution Franchise area. Col. 2 represent the total technical potential of natural gas units, based on existing market penetration for those end uses. Col. 3 represent the incremental market potential under one possible fuel switching scenario that involves a customer incentive of 50% of the capital cost of the equipment:

	Col. 1	Col. 2 Total Technical Potential (# of units)	Col. 3 Incremental Market Potential Over 5 Yrs. (# of units)
1	Furnaces	153,000	66,000
2	Water Heaters	214,000	161,000
3	Ranges	1,160,000	187,000
4	Clothes Dryers	1,100,000	190,000

This scenario is cost effective from a Total Resource Cost perspective, as presented in table 1a of the SeeLine report entitled "Fuel Switching and Enbridge Gas Distribution" (February 2006), filed in response to Consumers Council of Canada interrogatory #38 at Exhibit I, Tab 7 Schedule 38.

ii) Please refer to attached presentations:
Copy of presentation by Jim Schultz to the OEN – November 25, 2005
Copy of presentation by James Fidler to IndEco Strategic Consulting, January 2006.
Copy of presentation to Justice Committee by Lino Luison February 6, 2006

Witnesses: S. Clinesmith
P. Green
P. Squires

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iii) Fuel switching has been an integral part of the Company's growth initiatives for many years, although the programs have not been explicitly labeled as such. Please refer to Board Staff interrogatory 25 (c) for a summary of the financial impacts of the Company's growth programs for 2006, as filed in EB-2005-0001. The Company's fuel switching initiatives were imbedded in this portfolio.

iv) The following table breaks out the proposed $5 million increase in the Market Development budget into fixed and variable costs. Fixed costs will include research, promotional material, training, and program development costs, and variable costs include program incentives.

	Fixed Costs $ millions	Variable Costs $ millions	Total 2007 Increment $ millions
Residential	0.9	2.2	3.1
Business Markets	0.9	0.2	1.1
Marketing Communications	0.8	0.0	0.8
Total	2.6	2.4	5.0

v) Enbridge Gas Distribution is currently testing various offers and incentive levels for conversion to gas water heating on a small scale, in localized segments of the franchise area, to help the Company determine the threshold incentive level that motivates fuel conversion for a typical residential customer. In the low income market segment, Enbridge Gas Distribution assumes that a much higher share – possibly 100% - of the incremental cost of a gas water heater would have to be borne by the program delivery agent(s). The Company is also in consultation with water heater rental companies to explore rental offers that make the conversion more attractive to consumers.

vi) Typically market development activities such as fuel-switching do not provide revenue that is in excess of the costs of the first year. For example, costs that are used to stimulate the installation of a natural gas water heater are expended up front, yet the revenue generated from the water heater installation will be realized over the next 10 to 15 years. In addition, in the first year of attachment customers are attached at different times throughout the year and consequently do not provide a full year of revenue. For those customers that require a natural gas main extension and service the attachment is evaluated for financial feasibility using the EBO 188 Feasibility Guidelines which uses rates and revenue horizons based on the rate class (e.g., residential is based on a 40 year revenue horizon). Generally speaking, the short term negative rate impacts are more than offset by the longer term benefits, and overall rates should be lower as the result of programs.

vii) Enbridge Gas Distribution has not completed a full analysis of the opportunity and costs for low income customer water tank fuel switching. The Company is proposing to spend $925,000 on this program in 2007 and recognizes that if this budget must cover 100% of incremental costs plus program fixed costs, the potential number of participants is limited. For this reason, the Company will consider alternate arrangements for program delivery such as partnerships with other organizations to offset incentive costs, and is investigating the potential for creative rental offers for low income consumers.

viii) Market development activities will work to optimize the use of a variety of external partners across all market disciplines in efforts to promote cost-effective fuel-switching activities across all market sectors. In the residential sector, Enbridge Gas Distribution will use as one of its channels the Energylink™ Program to connect customers with professional contractors and retailers to find the natural gas energy solutions they need. The Energylink™ Program does not provide any additional advantage to any affiliates. Enbridge Gas Distribution does have a vested interest in market share retention and market share growth of natural gas burner-tip applications with existing and new natural gas customers. Enbridge Gas Distribution will continue to work with a diverse group of natural gas industry players across all market sectors to effectively deliver cost-effective programs.

ix) Please refer to Board Staff interrogatory #25 at Exhibit I, Tab 1, Schedule 25.

Witnesses: S. Clinesmith
P. Green
P. Squires

BOARD STAFF INTERROGATORY #25

INTERROGATORY

Ref: D1/T8/S1

Issue Number: 3.3
Issue: Is the Company's proposed fuel switching program appropriate?

EGD has requested an amount of $5.0 million in new initiatives aimed at promoting fuel switching activities. Please provide a breakdown of costs and the activities associated with each of the cost components.

a) How many conversions will this new initiative achieve in each of the first five years of its implementation?

b) Please provide the impact of this initiative on the distribution revenue during the first five years of its implementation?

c) Has EGD embarked on any similar initiatives before? If "Yes", please provide details of these prior initiative including volumetric and revenue impacts.

d) Has the Company performed a cost/benefit analysis of this initiative? If "Yes", please provide a report of this study. If "Not", please prepare and provide a detailed cost/benefit analysis.

e) As part of this initiative, the Company plans to raise awareness of natural gas and educate consumers on its benefits versus other alternate energy sources. Has EGD considered partnering with other vendors or Union Gas on this initiative to realise scale economies or share costs? Please provide details on any partnership initiatives including cost sharing and potential benefits. If EGD has not entered into any partnership, please provide reasons for not partnering on a generic initiative.

Witnesses: S. Clinesmith
P. Green
N. Ryckman
P. Squires

RESPONSE

A breakdown of costs and activities associated with these initiatives is included in Table 1 of this response.

a) Please refer to Table 1, Column 3 for the participants that will result in 2007.

b) Please refer to Table 1, Column 7.

c) In 2006, the Company's planned fuel switching initiatives were also imbedded in the Market Development portfolio. The financial impact of this 2006 portfolio is summarized below. Please note this information was previously filed as EB-2005-0001, Exhibit I, Tab 5, Schedule 41, as corrected 2005-09-07.

Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7
	Volume (million m3)	Revenue ($million)	O&M Cost ($million)	Measure Life NPV ($million)	TRC ($million)	SCT ($million)
Residential Market	29.5	2.2	4.7	1.9	43.5	55.7
Business Market	12.4	0.5	1.1	1.0	20.3	28.4
Total Market Development	41.9	2.7	5.8	2.9	63.8	84.1

d) Please refer to Table1, Column 8.

e) Enbridge Gas Distribution has considered partnering with vendors and Union Gas on this initiative to realize scale economies and/or sharing of costs. At this time, no detailed plans are available. Opportunities to reach consumers with a positive, common message about the benefits of natural gas for specific end-use applications will be explored.

Witnesses: S. Clinesmith
P. Green
N. Ryckman
P. Squires

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Table 1
2007 Regulatory Budget

	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 1
	RESIDENTIAL MARKET	Vol (10^6 m^3)	Number of Participants	Life	Program Costs ($)	Incremental Cost per Participant	5 Year Distribution Revenue ($m)	Life NPV ($m)	TRC ($m)	SCT ($m)
1	High Efficiency Furnace	6.49	3,174	18	108,000	800	3.70	2.31	22.95	25.02
2	ECM	0.33	5,000	18	-	550	0.12	0.19	(0.54)	(0.36
3	Mid Efficiency Furnace	0.30	123	18	19,850	400	0.17	0.11	1.11	1.21
4	Fireplace	1.77	5,303	12	170,690	700	0.68	0.61	(6.12)	(6.20
5	Grill/BBQ	0.07	1,477	12	20,200	250	0.03	0.01	(0.18)	(0.19
6	Range/Dryer/Front Load Axis Washer	1.26	12,966	12	30,300	300	0.48	0.49	0.03	0.20
7	Low Income (WH)-fuel switching	0.78	1,150	9	925,000	800	0.38	(0.56)	0.38	0.54
8	Interior Constr. Heat Res New Cons*	10.60	18,644	1	123,742	350	1.40	0.80	5.19	5.45
9	Interior Constr. Heat Small Comm*	0.37	107	1	17,916	350	0.02	0.00	0.35	0.36
10	Residential Fuel Switching (Water Heating)	1.03	1,518	9	358,000	600	0.47	(0.06)	1.79	1.99
11	Water Heating	0.99	2,500	9	49,100	600	0.39	0.26	1.49	1.68
12	Outdoor Living/Garage heating/Pool Heating	0.33	550	12	170,690	700	0.12	0.04	(1.11)	(1.30
13	EnergyLinkTM	8.00	22,933	12	1,036,300	466	3.04	2.06	1.30	1.93
		32.31	75,445		3,029,788		10.99	6.26	26.67	30.33
14							Less Overhead	(2.49)	(2.49)	(2.49
15							Net Benefits	3.77	24.18	27.84
	BUSINESS MARKET									
16	Multi - Family Housing	3.75	18	20	180,823	350,000	0.80	1.17	11.75	12.78
17	Forklift Conversion	1.26	139	15	40,600	15,000	0.26	0.33	5.53	5.66
18	Commercial Construction Heaters*	7.00	175	1	20,000	1,600	0.46	0.28	7.02	7.19
19	Institutional/Commercial/Industrial	0.52	1,000	20	20,000	1,000	0.15	0.24	1.52	1.66
20	Small Com'l Business Partners	1.24	55	15	36,702	2,000	0.32	0.38	5.20	5.55
21	Small Com'l Load Plus	1.96	700	15	87,264	2,500	0.48	0.60	6.46	6.94
22	Small Com'l Additions/NonComs	1.92	180	15	87,824	5,000	0.52	0.43	6.44	7.03
		17.65	2,267		473,213		2.99	3.42	43.92	46.80
23							Less Overhead	(1.68)	(1.68)	(1.68
24							Net Benefits	1.74	42.24	45.13
25							**Total Net Benefits**	**5.51**	**66.42**	**72.97**

* Volumes are fully effective in the 1st year; distribution revenue, NPV, TRC and SCT based on 1 year only.

Witnesses: S. Clinesmith
P. Green
N. Ryckman
P. Squires

Priority of energy issues

When asked to assign a priority to a series of specific energy issues (on a scale of 1 to 10, where 10 is highest priority), stakeholders again give the highest rating to the issue of electricity supply. Other issues with high importance include electricity reliability, electricity infrastructure and policy stability. Natural gas supply, natural gas pricing and competition are given a lower priority.

Since 2005, the importance assigned to the issue of conservation has increased slightly; electricity pricing and natural gas pricing receive somewhat lower ratings now than in 2005.

Priority of energy issues

Please rate the priority of the following energy issues on a ten-point scale, where a score of 1 means the issue is the lowest priority and 10 means it is the highest priority.

	2006	2005
	Mean	Mean
Electricity supply	9.1	9.1
Electricity reliability	8.6	8.4
Electricity infrastructure	8.5	–
Policy stability	8.4	8.2
Electricity pricing	7.6	8.0
Investor confidence in the energy sector	7.4	7.6
Public confidence in the energy sector	7.3	7.3
Energy conservation	6.9	6.5
Natural gas supply	6.4	6.2
Natural gas pricing	6.0	6.6
Competition	5.3	5.5

FUEL SWITCHING AND ENBRIDGE GAS DISTRIBUTION

FOR ENBRIDGE GAS LIMITED

By
SeeLine Group Inc.
416-703-8695

February 2006

1.0 INTRODUCTION

As part of its support for Enbridge Gas Distribution (EGD) marketing efforts, SeeLine Group Inc (SLG) undertook an assessment of the proposed electric fuel switching program. The focus of the analysis was the determination of the Total Resource Cost Test (TRC) for the proposed electricity to gas fuel switching technologies. These technologies include space heating, water heating, cooking and clothes drying.

2.0 APPROACH

SLG conducted two analyses for this study. The first analysis used technology and program input assumptions provided by Enbridge (Fuel_Switching_Option 2 Master_may25.xls). The second analysis used some of the input assumptions supplied by Enbridge; however, electricity usage data for clothes dryers, ranges and water heaters, was supplemented by information currently available from the Ontario Energy Board.

Both TRC analyses were conducted using the benefit and cost definitions and structures as approved by the Ontario Energy Board where the cost is defined as the increased societal cost of natural gas (as expressed by the avoided costs), the incremental equipment cost and the associated utility program support costs. The benefits are the avoided resource costs associated with a reduction in electricity use.

The TRC assessments were conducted using SLG's SeeTool™ TRC calculator. This tool and approach replicates both the DSStrategist™ model used in the past by Enbridge and the common approach used by electric utilities in Ontario currently undertaking Conservation and Demand Management TRC planning and analysis exercises.

Electricity avoided costs used in the analysis are those provided by the Ontario Energy Board. Avoided costs are expressed in eight costing periods for energy (winter peak, winter mid-peak, winter off-peak, summer peak, summer mid-peak, summer off peak, shoulder peak and shoulder off peak) and one (summer) for peak (demand). As such, all electricity savings values must also be defined in the same manner.

In absence of gas costs used to evaluate system expansion projects, the company's DSM avoided gas costs were used for this analysis. These costs were used for the EBO 2005-0001 rate case evidence and provide a good proxy for examining fuel switching programs.

2.0 RESULTS

Results from the first phase of this analysis are summarized in the tables below. Table 1a provides a summary of the proposed fuel switching program using the lower equipment life values for each technology.

Table 1a. Summary of TRC Results using Enbridge Data and Lower Equipment Life Assumptions

Program Results with Lower Equipment Life Assumptions
Total Resource Net Benefits
(shown in 2006 $'s)

	2006	2007	2008	2009	2010	Total
Furnaces (15 yrs)	$38,348,134	$ 49,310,597	$45,181,049	$29,497,987	$32,477,881	$194,815,647
Ranges (14 yrs)	$ 3,630,417	$ 4,594,486	$ 4,224,016	$ 2,831,876	$ 3,277,971	$ 18,558,766
Dryers (11 yrs)	$ 7,998,805	$ 10,638,713	$ 9,785,085	$ 6,255,385	$ 7,020,153	$ 41,698,142
Water Heaters (10 yrs)	$11,461,554	$ 35,878,424	$32,873,762	$21,615,245	$23,701,290	$125,530,276
Program Costs*	$ (3,059,729)					$ (3,059,729)
Total	**$58,381,187**	**$100,424,227**	**$92,065,920**	**$60,202,502**	**$66,479,306**	**$377,553,142**

* Marketing/Administration/Promotion Costs

Based on above results, the fuel switching program would provide positive net benefits for each year and technology as specified by the program assumptions. The total TRC net benefits for the full five years of the program are $377,553,142 (in 2006 dollars).

It should be noted that these and other TRC test results, do not include the $305,972,900 in incentive costs. These costs are merely transfer payments between the utility and the participant and therefore cancel each other out.

Table 1b. Summary of TRC Results using Enbridge Data and Higher Equipment Life Assumptions

Program Results with Higher Equipment Life Assumptions
Total Resource Net Benefits
(shown in 2006 $'s)

	2006	2007	2008	2009	2010	Total
Furnaces (17 yrs)	$ 44,949,956	$ 57,878,105	$ 53,031,066	$ 34,576,213	$ 38,099,274	$ 228,534,613
Ranges (15 yrs)	$ 4,307,348	$ 5,541,070	$ 5,095,007	$ 3,362,696	$ 3,940,171	$ 22,246,293
Dryers (13 yrs)	$ 9,925,804	$ 13,315,623	$ 12,248,091	$ 7,765,907	$ 8,758,977	$ 52,014,403
Water Heaters (13 yrs)	$ 15,145,647	$ 47,437,924	$ 43,465,204	$ 28,566,563	$ 31,331,634	$ 165,946,972
Program Costs*	$ (3,059,729)					$ (3,059,729)
Total	**$ 71,271,032**	**$ 124,174,730**	**$ 113,841,376**	**$ 74,273,388**	**$ 82,132,066**	**$ 465,682,552**

* Marketing/Administration/Promotion Costs

As would be expected, the higher equipment life assumptions yield greater TRC net benefits as shown in Table 1b. This is largely due to the longer lifecycle of net benefits. Under this scenario the fuel switching program would result in a net benefit of $465,682,552 under the TRC test.

The second analysis in this study, examined TRC results for the fuel switching program using electricity and gas data supplied by the OEB for dryers, ranges and water heaters, supplemented with Enbridge data for furnaces. Results from this analysis are below in Table 2.

Table 2. Summary of TRC Results using OEB and Enbridge Data

Program Results with OEB Assumptions
Total Resource Net Benefits
(shown in 2006 $'s)

	2006	**2007**	**2008**	**2009**	**2010**	**Total**
Furnaces (17 yrs)	$ 40,454,960	$ 52,090,295	$ 47,727,959	$ 43,730,950	$ 34,289,346	$ 218,293,510
Ranges (18 yrs)	$ 4,500,694	$ 5,784,007	$ 5,318,341	$ 4,872,953	$ 3,865,617	$ 24,341,613
Dryers (18 yrs)	$ (3,566,959)	$ (5,118,007)	$ (4,710,252)	$ (2,801,090)	$ (3,286,700)	$ (19,483,008)
Water Heaters (18 yrs)	$ 37,869,397	$ 48,467,826	$ 44,408,856	$ 32,885,153	$ 31,985,734	$ 195,616,965
Program Costs*	$ (3,059,729)					$ (3,059,729)
Total	**$ 76,200,369**	**$ 101,226,128**	**$ 92,746,912**	**$ 78,689,975**	**$ 66,856,007**	**$ 415,719,391**

* Marketing/Administration/Promotion Costs

Once again, results indicate overall that the program provides positive net benefits under the TRC. However, dryers are not costs effective using data provided by the OEB. This is largely due to higher gas consumption and lower electricity savings assumptions.

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Exhibit JT1.31
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Attachment

The following tables provide a more detailed summary of results for each scenario.

Table 3. Enbridge Gas Fuel Switching Program with Enbridge's Gas and Electricity Data

Summary of Fuel Switching Opportunities Using Enbridge Data
Total Resource Cost Test Net Benefits
(shown in 2006 $'s)

	2006	2007	2008	2009	2010
Furnaces (15 Yrs)					
Existing Homes	$ 23,205,868	$ 35,436,429	$ 32,468,783	$ 17,850,318	$ 21,805,654
System Expansion	$ 5,325,549	$ 4,879,557	$ 4,470,916	$ 4,096,496	$ 3,753,432
Infill	$ 5,917,276	$ 5,421,730	$ 4,967,684	$ 4,551,662	$ 4,170,480
New Homes	$ 3,899,441	$ 3,572,879	$ 3,273,666	$ 2,999,511	$ 2,748,315
Total	**$ 38,348,134**	**$ 49,310,597**	**$ 45,181,049**	**$ 29,497,987**	**$ 32,477,881**
Furnaces (17 Yrs)					
Existing Homes	$ 27,329,303	$ 41,733,105	$ 38,238,139	$ 21,022,129	$ 25,680,286
System Expansion	$ 6,271,842	$ 5,746,603	$ 5,265,350	$ 4,824,400	$ 4,420,377
Infill	$ 6,968,713	$ 6,385,114	$ 5,850,388	$ 5,360,444	$ 4,911,530
New Homes	$ 4,380,098	$ 4,013,283	$ 3,677,188	$ 3,369,240	$ 3,087,081
Total	**$ 44,949,956**	**$ 57,878,105**	**$ 53,031,066**	**$ 34,576,213**	**$ 38,099,274**
Ranges (14 Yrs)					
Existing Homes	$ 2,050,461	$ 3,131,240	$ 2,869,013	$ 1,577,247	$ 2,116,409
System Expansion	$ 104,876	$ 103,485	$ 101,591	$ 99,289	$ 96,660
Infill	$ 116,529	$ 114,983	$ 112,879	$ 110,321	$ 107,400
New Homes	$ 1,358,551	$ 1,244,778	$ 1,140,533	$ 1,045,018	$ 957,503
Total	**$ 3,630,417**	**$ 4,594,486**	**$ 4,224,016**	**$ 2,831,876**	**$ 3,277,971**
Ranges (15 Yrs)					
Existing Homes	$ 2,578,143	$ 3,937,057	$ 3,607,346	$ 1,983,148	$ 2,661,061
System Expansion	$ 131,866	$ 130,117	$ 127,736	$ 124,841	$ 121,535
Infill	$ 146,517	$ 144,574	$ 141,928	$ 138,712	$ 135,039
New Homes	$ 1,450,823	$ 1,329,323	$ 1,217,998	$ 1,115,996	$ 1,022,536
Total	**$ 4,307,348**	**$ 5,541,070**	**$ 5,095,007**	**$ 3,362,696**	**$ 3,940,171**
Dryers ([illegible] Yrs)					
Existing Homes	$ 5,351,752	$ 8,172,610	$ 7,488,190	$ 4,116,652	$ 5,029,200
System Expansion	$ 336,897	$ 327,976	$ 318,187	$ 307,737	$ 296,805
Infill	$ 374,330	$ 364,418	$ 353,541	$ 341,930	$ 329,784
New Homes	$ 1,935,825	$ 1,773,709	$ 1,625,168	$ 1,489,067	$ 1,364,364
Total	**$ 7,998,806**	**$ 10,638,713**	**$ 9,785,086**	**$ 6,255,385**	**$ 7,020,153**
Dryers ([illegible] Yrs)					
Existing Homes	$ 6,825,264	$ 10,422,797	$ 9,549,933	$ 5,250,100	$ 6,413,903
System Expansion	$ 429,656	$ 418,279	$ 405,794	$ 392,467	$ 378,525
Infill	$ 477,396	$ 464,754	$ 450,882	$ 436,074	$ 420,584
New Homes	$ 2,193,489	$ 2,009,794	$ 1,841,482	$ 1,687,266	$ 1,545,965
Total	**$ 9,925,804**	**$ 13,315,623**	**$ 12,248,091**	**$ 7,765,907**	**$ 8,758,977**
Water Heaters (10 Yrs)					
Existing Homes	$ 7,108,810	$ 25,328,823	$ 23,207,644	$ 12,758,622	$ 15,586,371
System Expansion	$ 1,631,411	$ 4,099,989	$ 3,756,633	$ 3,442,031	$ 3,153,776
Infill	$ 1,812,679	$ 4,555,544	$ 4,174,037	$ 3,824,479	$ 3,504,196
New Homes	$ 908,653	$ 1,894,069	$ 1,735,449	$ 1,590,112	$ 1,456,947
Total	**$ 11,461,554**	**$ 35,878,424**	**$ 32,873,762**	**$ 21,615,245**	**$ 23,701,290**
Water Heaters (13 Yrs)					
Existing Homes	$ 9,409,859	$ 33,527,503	$ 30,719,720	$ 16,888,457	$ 20,631,519
System Expansion	$ 2,159,482	$ 5,427,114	$ 4,972,617	$ 4,556,182	$ 4,174,621
Infill	$ 2,399,425	$ 6,030,126	$ 5,525,130	$ 5,062,424	$ 4,638,468
New Homes	$ 1,176,880	$ 2,453,181	$ 2,247,738	$ 2,059,500	$ 1,887,026
Total	**$ 15,145,647**	**$ 47,437,924**	**$ 43,465,204**	**$ 28,566,563**	**$ 31,331,634**

As shown in Table 3. each technology scenario would be cost effective from a TRC perspective.

Table 4. Enbridge Gas Fuel Switching Program with both Enbridge and OEB's Gas and Electricity Data

Summary of Fuel Switching Opportunities Using OEB Data
Total Resource Cost Test Net Benefits
(shown in 2006 $'s)

	2006	2007	2008	2009	2010
Furnaces (15 Yrs)					
Existing Homes	$ 20,885,281	$ 31,892,786	$ 29,221,904	$ 16,065,286	$ 19,625,088
System Expansion	$ 4,792,994	$ 4,391,602	$ 4,023,824	$ 3,686,846	$ 3,378,089
Infill	$ 5,325,549	$ 4,879,557	$ 4,470,916	$ 4,096,496	$ 3,753,432
New Homes	$ 3,509,497	$ 3,215,592	$ 2,946,300	$ 2,699,560	$ 2,473,484
Total	**$ 34,513,320**	**$ 44,379,537**	**$ 40,662,944**	**$ 26,548,189**	**$ 29,230,093**
Furnaces (17 Yrs)					
Existing Homes	$ 24,596,373	$ 37,559,794	$ 34,414,325	$ 31,532,275	$ 23,112,257
System Expansion	$ 5,644,658	$ 5,171,942	$ 4,738,815	$ 4,341,960	$ 3,978,339
Infill	$ 6,271,842	$ 5,746,603	$ 5,265,350	$ 4,824,400	$ 4,420,377
New Homes	$ 3,942,088	$ 3,611,955	$ 3,309,470	$ 3,032,316	$ 2,778,373
Total	**$ 40,454,960**	**$ 52,090,295**	**$ 47,727,959**	**$ 43,730,950**	**$ 34,289,346**
Ranges (18 Yrs)					
Existing Homes	$ 2,684,511	$ 4,099,491	$ 3,756,176	$ 3,441,613	$ 2,522,714
System Expansion	$ 168,992	$ 164,517	$ 159,607	$ 146,240	$ 148,881
Infill	$ 187,769	$ 182,797	$ 177,341	$ 162,489	$ 165,424
New Homes	$ 1,459,423	$ 1,337,202	$ 1,225,217	$ 1,122,611	$ 1,028,597
Total	**$ 4,500,694**	**$ 5,784,007**	**$ 5,318,341**	**$ 4,872,953**	**$ 3,865,617**
Dryers (18 Yrs)					
Existing Homes	$ (2,990,985)	$ (4,567,505)	$ (4,184,996)	$ (2,300,712)	$ (2,810,717)
System Expansion	$ (152,982)	$ (150,952)	$ (148,190)	$ (144,832)	$ (140,997)
Infill	$ (169,979)	$ (167,725)	$ (164,656)	$ (160,924)	$ (156,663)
New Homes	$ (253,014)	$ (231,825)	$ (212,411)	$ (194,622)	$ (178,323)
Total	**$ (3,566,959)**	**$ (5,118,007)**	**$ (4,710,252)**	**$ (2,801,090)**	**$ (3,286,700)**
Water Heaters (16 Yrs)					
Existing Homes	$ 22,543,286	$ 34,425,210	$ 31,542,249	$ 24,771,584	$ 21,183,933
System Expansion	$ 6,081,746	$ 5,572,426	$ 5,105,760	$ 1,851,777	$ 4,286,398
Infill	$ 6,757,495	$ 6,191,585	$ 5,673,066	$ 2,057,530	$ 4,762,664
New Homes	$ 2,486,869	$ 2,278,605	$ 2,087,781	$ 4,204,261	$ 1,752,738
Total	**$ 37,869,397**	**$ 48,467,826**	**$ 44,408,856**	**$ 32,885,153**	**$ 31,985,734**

As shown in Table 4, all technologies remain cost effective from a TRC perspective using OEB data with the exception of dryers. Based on the savings and cost data outlined in the OEB measures list, this measure would results in a negative TRC for each year in the five year plan.

3.0 CONCLUSIONS

The Ontario Energy Board has provided a list of prescriptive savings for many typical residential and commercial technologies. Where appropriate, these values are recommended for use by Enbridge.

The following table provides a summary of the saving and cost inputs as supplied by Enbridge and those provided by the OEB measure list.

Table 5. Comparison of Enbridge Data vs. OEB Data

	Enbridge	OEB
Furnaces		
Gas Consumption	1800 m3	n/a
kW Savings	17100 kW	n/a
kWh Savings	17000 kWh	n/a
Equipment Life	15 and 17 Years	n/a
Freeriders	0%	n/a
Incremental Equipment Costs	$1,750 (new) and $3,243 (existing)	n/a
Ranges		
Gas Consumption	100 m3	81 m3
kW Savings	0.5 kW	0 kW
kWh Savings	880 kWh	735 kWh
Equipment Life	14 and 15	18
Freeriders	0%	10%
Incremental Equipment Costs	$225 (new) and $475 (existing)	$400 (new)
Dryers		
Gas Consumption	100 m3	112 m3
kW Savings	.165 kW	0.04 kW
kWh Savings	1200 kWh	916 kWh
Equipment Life	11 and 13	18
Freeriders	0%	10%
Incremental Equipment Costs	$25 (new) and $275 (existing)	$0 (new)
Water Heaters		
Gas Consumption	728 m3	680 m3
kW Savings	1.14 kW	0.357 kW
kWh Savings	4,950 kWh	5,000 kWh
Equipment Life	10 and 13	18
Freeriders	0%	10%
Incremental Equipment Costs	$454 (new) and $545 (existing)	$600 (new)

The impact on TRC net benefits is significant in the case of dryers when using the OEB data; however under each scenario (low equipment life assumptions, higher equipment life assumptions and OEB data) the overall five year fuel switching program provides positive TRC net benefits.

It should also be noted that the forecast of avoided gas and electricity costs play a significant role in the cost effectiveness of fuel switching programs. Based on the most current forecast of gas and electricity, the saving benefits from electricity consumption far outweigh the increases in gas consumption. However, if either energy forecasts were to change, another examination of TRC net benefits for fuel switching opportunities would be recommended.

EB-2006-0021
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Written Submission

Enbridge Gas Distribution to the Ontario Power Authority in the matter of the province's energy supply mix August 26, 2005

Introduction: Enbridge Gas Distribution ("Enbridge") is pleased to provide this response to the Call for Written Submissions issued by the Ontario Power Authority in the matter of the province's energy supply mix. The following considerations reflect Enbridge's 157-year history of anticipating and adapting to changing energy circumstances in Ontario, and meeting the changing needs of generations of customers.

Natural gas - Part of a diverse energy portfolio: Ontario's natural gas sector is wellpositioned to play its part in realizing the government's stated goal of a diverse supply of competitively priced power within a conservation culture:

- *Sufficient supply:* There will be enough natural gas supply to meet future needs. Natural Resources Canada has calculated total remaining natural gas reserves in North America alone at 75 times current consumption levels. In addition, significant additional reserves have been and are being identified.

- *Fair and reasonable prices:* Natural gas is and will remain an economic energy choice. Based on the experience of Enbridge's own customers in recent years, natural gas has been on average about 39% less expensive than electricity and 20% less expensive than oil.

- *Environmental benefits:* Environment Canada has noted that natural gas-fired power generation emits the lowest level of greenhouse gases among all fossil fuels. In addition, an independent study released by the Ministry of Energy in April 2005 concluded that a combination of nuclear and natural gas- generated electricity was the lowest-cost energy scenario in terms of money, public health and the environment.

- *Conservation culture:* The natural gas sector has initiated a number of energy efficiency programs to help customers reduce the amount of natural gas they use. Programs implemented by Enbridge between 1995 and 2004 alone reduced consumption by the equivalent of the gas used by 620,000 homes in one year. Those same programs reduced carbon dioxide emissions by the equivalent of removing 750,000 cars from the road for one year.

- *Advancing stated public policy objectives:* As noted above, natural gas can advance the Ministry's stated desire for diversity of supply. It also advances the findings of an Ontario Energy Board ("OEB") report issued in March 2005, which recognized the important and growing role of natural gas and natUral gas infrastructure in the province's energy system.

Fuel switching - The focus of this submission: There are a number of ways in which natural gas can contribute to the achievement of the province's stated energy needs and objectives. One 'way is through large scale electricity generation. Another is through distributed energy. Still another is through energy efficiency models that provide demand side management and other programs tailored to particular classes of customers.

The focus of this submission, however, is on another aspect of the natural gas component of a diverse energy mix. This aspect - fuel switching - entails the switching of customers from electric appliances to natural gas appliances that can perform the same chores, often in a more effective and cost-efficient way.

Fuel switching - The plan and the benefits: The remainder of this submission discusses a five-year plan for the switching of 1,043,425 furnaces, water heaters, ranges and dryers from electricity to natural gas. Under this initiative, the benefits to Ontario would include:

- *Reduced electricity demand:* Peak load electricity demand would be reduced by 1,490 megawatts.
- *Avoided generation costs:* The move to natural gas-fired appliances would realize avoided electricity generation costs of $1.146 billion.
- *Decreased greenhouse gas emissions:* The switch from electric to natural gas appliances would lower greenhouse gas emissions by 2.5 million tonnes.

Fuel switching - The potential for quick 'wins': One of the key attributes of the fuel switching initiative is the speed with which the benefits could be realized. This is due, in part, to the fact that the natural gas infrastructure and technology to implement such a program are already in place. There follow three areas or quick 'wins' that demonstrate the benefits that can be achieved for Ontario in short order, using existing technology, and building on current or reinforced infrastructure.

- *Space heating:* Electrical residential space heating can account for up to 60% of residential electricity use. Switching the space heating source from electricity to natural gas furnaces could save $1.1 billion in avoided generation costs.
- *Water heating:* Heating water electrically can total up to 20% of residential electricity use. Switching to natural gas tankless water heaters can increase energy efficiency and lower customer costs
- *Helping low income residents:* Approximately 14% of Ontario residents live at or near the poverty line. More than 50% of them use electric water heaters, which cost more to operate than natural gas heaters. Thus, people who can least afford it are paying more to heat their water than they have to. Switching their water heaters from electricity to natural gas has the potential to save this group some $146 million in avoided generation costs.

Fuel switching. The role of incentlres: One way to encourage the implementation of arry fuel switcrung initiative is to make the prospect attractive to customers. Here, as elsewhere in the economy, retail prices can influence consumer choices and buying decisions. The cost of purchasing new natural gas appliances, before the end ofthe useful life of existing electricity appliance stock, can be an impediment to change with many . customers. This fact alone can deter consumers from pursuing the natural gas option, even though they can realize significant cost savings over the life of those natural gas appliances.

One way to encourage consumers to choose the natural gas option, and to realize the potential benefits for the province, is through the use of direct-to-ratepayer incentives for purchasing natural gas appliances. Such incentives could be provided in one of two ways. The frrst is by the provincial government itself. The second is through the regulatory process in which local utilities would factor such incentives into their rate structure, build cost recovery plans into their rate submissions, and seek approval of those submissions through the OEB in the normal course.

Either way, if direct-to-ratepayer incentives were provided for 50% of the purchase price of switching to natural gas appliances, and as the Fuel Switching - Summary Results document appended to this submission indicate, Ontario would still realize net avoided generation costs of $617 million unger the proposed five-year fuel switching program.

Fuel switching· Other considerations: Enbridge recognizes that other considerations are associated with the proposed fuel switching initiative. One is that the cost of the related system expansion would fall within natural gas utility rates. Another is that the demand for natural gas would increase. Analysis suggests, however, that the increased use would equal just 0.2% of total North American demand. A third factor is the proposed five-year timetable itself. Enbridge believes that this schedule, while aggressive, is achievable using current technology and building on current infrastructure._

In conclusion - Natural gas, fuel switching, and the benefits to Ontario: By way of summary, and in support of its proposed five-year fuel switching initiative from electric to natural gas appliances, Enbridge Gas Distribution submits that:

- Natural gas can do its part: Natural gas is well-equipped to playa significant role within Ontario's changing energy mix. It is plentiful, economical, and environmentally sound.

- Fuel switching is a viable and achievable initiative: Fuel switching from electric to natural gas appliances - an initiative that is being pursued elsewherecan be achieved at low risk through existing infrastructure and technology.

- Ontario will benefit: The fuel switching initiative will, among other things, address the government's stated policy objectives, reduce electricity demand, avoid generation costs and lower greenhouse gas emissions.

Fuel Switching- Summary Results

	Over 5 years
Megawatts Saved (Diversified Demand)	**1,490**
Net GHG Emissions Reduced	**2.5 million tonnes**
Cost of 1,490 MW NG Fired Generation	**$1.146 billion**
Incentive Cost (@ 50% of replacement)	**$0.529 billion**
Avoided Generation Cost	**$0.617 billion**
Ratio of NG Fired Generation Costs to Incentive	**2to 1**
Total Electric Appliances switched	**1,043,425**
Furnaces	**114,875**
Water Heaters	**279,200**
Ranges Dryers	**323,000**
	326,350

Market Transformation Assumptions

Enbridge Gas Distribution Inc.			Market Penetration				
		5Years		**Existing Home**		New Homes	
Residential Customers	1,525,000		**Appliance**	**Current**	**Proposed**	**Current**	**Proposed**
New Home additions	40,000	200,000	**Furnaces**	90%	93%	98%	100%
System Expansion/year	4,500	22,500	**Water Heaters**	86%	93%	91%	96%
Infill Customers/year	5,000	25,000	**Ranges**	24%	34%	24%	34%
			Dryers	30%	46%	30%	40%

System Expansion	35% electricity /65% oil
Infill Customers	35% electricity /65% oil
Heating only	3.5% electricity /65% oil

Union **Gas**			**Market Penetration**				
		5 Years		**Existing Home**		New Homes	
Residential Customers	1,200,000		**Appliance**	**Current**	**Proposed**	**Current**	**Proposed**
New Home additions	20,000	100,000	**Furnaces**	92%	95%	100%	100%
System Expansion/year	1,000	5,000	**Water Heaters**	85%	92%	86%	96%
Infill Customers/year	4,000	20,000	**Ranges**	19%	29%	19%	29%
			Dryers	21%	31%	21%	31%

System Expansion	50% electricity / 50% oil
Infill Customers	50% electricity / 50% oil
Heating only	50% electricity / 50% oil

- Incentives to utilities will be required for market transformation and should be paid annually.

Utilities should submit market transformation proposals as part of the filing in the first year of the multi-year plan. Proposals should outline objectives, target market, and budget.

Upon each subsequent multi-year plan submission, the progress on Market Transformation would be reported and the Utility would decide to continue to pursue a market transformation project or to discontinue the activity.

As stated, an incentive for Market Transformation programs is essential. Market Transformation programs must compete for Utility resources in the same way as any other program. Given the multi-year nature and difficulty of measurement in each year, Union and Enbridge have developed an approach to calculating the incentive for Market Transformation programs that is outlined in the DSM Handbook filed in Tab 3.

FUEL SWITCHING

It is Union's view that fuel switching from other fuels to natural gas should not be considered a DSM program as it does not reduce natural gas consumption. Instead, fuel switching should be run as a separate program by the utility.

Electricity conservation in Ontario has been largely driven by a need to address the existing and expected supply imbalance for electricity. Peak electricity demand exceeds Ontario's power generation capacity and increases the need for expensive electricity imports. Additionally, Ontario has committed to phasing out coal fired generation causing further pressure on the supply shortfall.

While new generation is clearly required, Ontario must also consider conservation as an essential means to address the issue. The ability to install new power generation capacity is a longer-term initiative. Fuel switching from electricity to natural gas is an integral part of the solution to the electricity supply imbalance in the near term.

The Board can send a strong message and set a positive policy direction by approving a specific fuel switching program for natural gas utilities. Union proposes that a separate fuel switching program be approved by the Board. The program would set budgets and report results in a similar fashion to DSM programs. The budget for fuel switching should be set in the same way as the DSM budget. A maximum budget of 2% of distribution revenue should be established in rates for the duration of the fuel switching plan. The utility would establish an actual budget in the test year and would apply the same rules to the budget and actual spending as are applied in the DSM framework. That is, Union would build the 2% budget into rates and would return to the ratepayer any unspent portion of the budget through a deferral account.

It is important to note that fuel switching is a complex issue and requires a coordinated approach among natural gas utilities, government, government agencies such as the OPA and electric LDCs. Union would seek partnerships in the delivery of fuel switching programs in order to ensure the resources are adequate and the focus is results based. Union would submit to the Board in the test year a fuel switching plan, similar to the DSM plan, establishing target markets, input assumptions and program descriptions. Results would be reported on an annual basis in a similar fashion to the annual DSM results reporting. Given the inherent nature of fuel switching programs, there would be no need for incentive mechanisms (i.e., SSM) or revenue adjustments (i.e., LRAM).

SUMMARY

Union's proposal outlines a framework that will meet the objectives and principles outlined by both Union and Enbridge in the joint submission in Tab 1.

Union emphasizes that it is important to establish a framework that creates certainty around the "rules" of DSM over not just one DSM Plan but over many DSM Plans. It is not productive to continually revisit the same items in each successive plan filing.

It is also essential in considering a framework to realize that the key framework items do not work discretely, but as interdependent items. Changing one can only be done by considering the appropriate changes to the other framework items in order to ensure that the goals and objectives of DSM in Ontario are maintained and not compromised.

DIRECT ENERGY MARKETING LIMITED INTERROGATORY #1

INTERROGATORY

Issue Number: 7.5
Issue: Is the Applicant's proposal of open bill access appropriate and consistent with the Board's direction in RP-2005-0001?

What are the utility and ratepayer advantages of having open bill access in relation to the Enbridge Gas Distribution Inc. ("EGD") bill? What was the impetus, even before Direct Energy obtained access to the bill, for having services on the bill and does that impetus still exist?

RESPONSE

There are clear advantages to all parties, including the customer, of having open bill access. Allowing customers to pay for the rental or financing of their natural gas appliance product via the utility bill helps to overcome a significant first cost barrier. This barrier relates to the higher capital cost outlay of natural gas equipment versus competing fuel-type equipment. Utility bill access provides a valuable service for customers by allowing them to acquire natural gas appliances with more manageable payments and with improved convenience.

By overcoming this market barrier, open bill access assists the Company in meeting key objectives to maintain and increase the growth of natural gas throughput and to provide additional DSM opportunities. Throughput growth ensures the long term sustainability of the Company's assets, while reducing rates for customers. Historically, allowing customers to rent and finance natural gas appliances on their utility bill was a major impetus in facilitating the market place along with a focused delivery channel even before Direct Energy obtained access to the bill. It enabled the market share for natural gas water heaters to increase from less than 50% in 1958 – the start of the water heater rental program to 89% in 2000.

Witnesses: P. Green
K. Lakatos-Hayward
S. McGill

Table 1

Impact on Distribution Revenue from Declining Water Heater Market Share

Water Heater Load (m3)	640
Marginal Distribution Revenue/m3 (2006 rates)	$ 0.09
Annual Distribution Revenue / Water Heater	$ 58.13
Number of Water Heater Customers	1,671,317.00
Impact on Distribution Revenue from 1% decrease in Market Penetration	$ (971,556.63)
Impact on Distribution Revenue from 5% decrease in Market Penetration	$ (4,857,783.14)
Impact on Distribution Revenue from 10% decrease in Market Penetration	$ (9,715,566.28)
Impact on Distribution Revenue from 20% decrease in Market Penetration	$ (19,431,132.56)

Table 1 shows the impact on distribution revenue from declining water heater market share. Over the past 5 years penetration levels have decreased from 89% to 86%, necessitating a higher revenue requirement in the order of $3.8 million. Penetration rates of other natural gas appliance products have also stagnated since 2002, coincident with the closure of major retail outlets specializing in natural gas products.

One benefit of Open Bill Access, therefore, is to increase the penetration of natural gas appliance products which improves overall distribution revenues and revenue requirement for ratepayers and the Company.

Open Bill Access also has a direct ratepayer benefit by lowering the forecast of O&M costs. This benefit amount is being revised as part of the 2007 draft interim solution which is anticipated to be tabled with the open bill consultative in mid-November for their consideration and input. As additional third parties transact on the bill, it is anticipated that this amount would increase over time. In addition, any net earnings from open bill access are proposed to be shared 50:50 with ratepayers, providing an additional benefit.

Witnesses: P. Green
K. Lakatos-Hayward
S. McGill

Schedule "A"
Potential Promotional Offerings*

Category	Natural Gas Elements	Complementary Elements
1. **Heating, Ventilation and Air Conditioning Equipment**	➢ Furnaces ➢ Water Heaters (Purchase or Rental) ➢ Boilers and Hydronics ➢ In Floor Radiant Heating ➢ Fireplaces	➢ Air Conditioners ➢ Indoor Air Quality Equipment
2. **HVAC Ancillary Equipment**		➢ HEPA Filters ➢ HRVs, EPVs ➢ Humidifiers, Electronic Air Cleaners ➢ Thermostats (Programmable)
3. **Service Programs**	➢ Heating and Air Conditioning Maintenance Programs. ➢ Heating and Air Conditioning Service / Protection Plans ➢ Insurance Programs – Lifestyle Products ➢ (e.g. Ranges, Dryers, Barbecues, Patio Heaters, Campfires).	
4. **Retail "White Goods"**	➢ Ranges ➢ Dryers ➢ Barbecues ➢ Pool Heaters ➢ Campfires ➢ Patio Heaters	
5. **Demand Side Management (DSM) Programs and Energy Messages**	➢ Programs and Services ➢ Energy Efficiency Efforts	
6. **Electric Contract Demand Management (CDM) Programs and Energy Messages**		➢ Programs and Services ➢ Energy Efficiency Efforts
7. **ENERGY STAR for New Homes and natural gas appliances**	➢ Builder New Home category promoted homes and sites with Energy Star labelling with natural gas appliances	

* The products and services set out in the table above are intended to provide general guidelines only. Notwithstanding anything to the contrary set forth elsewhere herein, Enbridge Gas Distribution reserves the right to, at any time, in its sole and absolute discretion, reject any proposed promotion. The Company will not provide the Service in relation to promotion of any natural gas commodity product offerings, nor in relation to promotions of products or services that compete with natural gas. The Company may allow for promotion of bundled products and services where the primary focus of such promotion is on natural gas, energy appliance and complementary products or energy efficiency.

K6.5

The Board is satisfied with the Financial Package proposal for market transformation. GEC argued for a much larger budget for market transformation and lost opportunity projects. Utility witnesses stated that the utilities could not effectively spend these budgets. The Board notes that the proposal regarding utility incentives for these programs does not achieve the level of certainty that exists for other elements of the Financial Package. While GEC argued for a more concrete incentive mechanism, the witnesses at the hearing were largely in agreement that market transformation programs are not necessarily amenable to fixed and inflexible rules. The Board agrees. The Board therefore accepts the proposal as filed.

Targeted Programs (Issues 13.1, 13.2, 13.3)

The Financial Package agreement makes the following proposals:

> "Parties to this settlement accept that low-income customers face barriers to access DSM programs which are unique to this group of customers. Accordingly, parties to this settlement agree that it is appropriate to establish a minimum amount of spending on targeted low-income customer programs in the residential rate classes of both Utilities. It is agreed that each utility will spend out of its DSM budget a minimum of $1.3 million, or 14% of each respective utility's residential DSM program budget, whichever is greater. For clarity, a utility may expend more than $1.3 million or 14% of its residential DSM program budget if the utility considers it appropriate. The Utilities each agree to increase the $1.3 million spending floor by the budget escalation factor appropriate for the utility (i.e. EGD 5%; Union 10%) in each of the second and third years of a three year plan.
>
> The parties to this settlement further agree that of the $1.0 million budget for market transformation programs, each utility will expend no less than 14% on targeted low-income market transformation programs.

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> The Utilities agree that by the establishment of this spending level floor, they will not, as a result, reduce planned DSM spending in other rate classes or sectors which are directed at low-income residents (e.g. social housing multi-unit residential spending) or their spending on fuel switching targeted to low-income customers."
>
> "Each of the utilities is at liberty to develop appropriate eligibility criteria for low income residential programs, and each utility agrees to consult with VECC in respect of the development of eligibility criteria and low-income program parameters. Parties to this settlement generally accept that criteria presently used by various levels of government for the purposes of determining low income eligibility may be appropriate for use by the utilities."

The only customer segment proposed to the Board for targeted programs were those for low-income customers. The Board finds the Financial Package proposal to be reasonable. The proposed spending floor should ensure that low-income consumers have access to DSM programs at least in approximate proportion to their percentage of residential revenue. LIEN argued that spending on low-income DSM programs should be equal to 18% of the total residential class DSM budget, assuming the total DSM budget is split proportionately amongst all rate classes. Under Issue 1.7, the Board has already stated its acceptance of budget allocations that are not strictly proportional to customer class revenue. There was conflicting evidence in the hearing as to the estimated proportion of low-income households within the residential sector. LIEN argued that the proportion was 18% while the Partial Settlement proponents argued that 14% was closer to the actual proportion. The Board finds LIEN's evidence on this matter unconvincing and finds that 14% is supported by the evidence. The Board, therefore, accepts the proposal that each utility will annually spend 14% of the residential DSM budget or $1.3 million on low-income programs, whichever amount is greater.

Ontario Energy Board

Commission de l'Énergie de l'Ontario

Ontario

EB-2006-0021

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

AND IN THE MATTER OF a generic proceeding initiated by the Ontario Energy Board to address a number of current and common issues related to demand side management activities for natural gas utilities.

BEFORE: Pamela Nowina
Presiding Member and Vice Chair

Paul Vlahos
Member

Ken Quesnelle
Member

DECISION WITH REASONS

August 25, 2006

EXECUTIVE SUMMARY

The Ontario Energy Board (the “Board”) determined the original regulatory framework for gas utility sponsored Demand Side Management (“DSM”) programs through guidelines established in its EBO 169-III Report of the Board dated July 23, 1993. DSM programs are programs which assist utility customers in reducing their natural gas consumption. Since 1995, Union Gas Limited (“Union”) and Enbridge Gas Distribution Inc, (“EGD”) have been filing DSM plans in response to the directives of the Board in the EBO 169-III Report.

In the Board’s EB-2005-0001 decision dealing with EGD’s 2006 rates, the Board announced its intention to convene a generic proceeding to address a number of current and common issues related to DSM activities for natural gas utilities – this decision. In the ensuing Notice of Hearing, the Board stated that the hearing will result in orders under section 36 of the Ontario Energy Board Act. The Board’s findings in this decision, therefore, are orders of the Board pursuant to section 36 of the Act.

At the beginning of the oral hearing the Board was presented several documents which segmented the issues list into four categories. The categories consisted of a list of completely settled issues, a list of partially settled issues to which most intervenors and the utilities agreed, a list of partially settled issues to which all intervenors agreed with the exception of the utilities, and, a list of completely unsettled issues. At the beginning of the oral hearing the Board accepted the completely settled issues as proposed. The oral hearing dealt with the issues contained in the two partial agreements, and other unsettled issues. The oral phase of the hearing, including argument, was concluded on July 28, 2006.

The Board’s decision deals with a large number of issues relating to DSM. Generally, a rules-based and framework approach has been established where appropriate and practical. Below is a list of the broader matters that have been decided.

- A three-year term for the first DSM plan
- Processes for adjustments during the term of the plan
- Formulaic approaches for DSM targets, budgets, and utility incentives
- Determination of how costs should be allocated to rate classes
- A framework for determining savings
- A framework and process for evaluation and audit
- The role of the gas utilities in electric Conservation and Demand Management activities and initiatives

The Board will issue a Procedural Order to commence the next phase dealing with the determination of the input assumptions after which the gas utilities can file their respective three-year DSM plans.

DECISION –PHASE 1

CHAPTER 1 - INTRODUCTION

The Ontario Energy Board (the “Board”) determined the original regulatory framework for gas utility sponsored Demand Side Management (“DSM”) programs through guidelines established in its EBO 169-III Report of the Board dated July 23, 1993. DSM programs are programs which assist utility customers in reducing their natural gas consumption. Since 1995, the gas utilities have filed DSM plans in response to the directives of the Board in the EBO 169-III Report.

The EBO 169-III Report provided guidelines to assist the utilities in the development and implementation of their respective DSM plans. Although the objectives and principles have evolved somewhat over the years to reflect changing market and industry conditions, they remain essentially unchanged. These DSM plans formed part of the gas utilities rate cases and were reviewed annually.

Over the past decade there have been occasions where rules for DSM programs have been challenged, requiring further interpretation and scrutiny by the Board. In addition, the Board has been required to frequently make decisions on similar DSM issues for the two large gas utilities, Union Gas Limited (“Union”) and Enbridge Gas Distribution (“EGD”), in separate proceedings. This has lead to increased regulatory burden for all parties and inconsistent practices by the two utilities. These concerns and the heightened focus on conservation and demand side management for the energy sector as a whole were the impetus for the Board to re-examine the DSM regime as it pertains to these two gas utilities through this generic proceeding.

In the Board's partial decision in EGD's 2006 rates application (EB-2005-0001 / EB-2005-0437), the Board announced its intention to convene a generic proceeding to address a number of current and common issues related to DSM activities for natural gas utilities. In the ensuing Notice of Hearing, the Board stated that the hearing will result in orders under section 36 of the Ontario Energy Board Act, 1998 (the "Act"). The Board's findings in this decision, therefore, should be considered orders pursuant to section 36 of the Act.

The Notice further stated that the following would be among the topics the Board would evaluate in making orders relating to the operation, evaluation and auditing DSM plans starting January 1, 2007:

- timing of the schedule for submitting and reviewing DSM plans,
- determination and use of planning assumptions for generic energy efficiency measures and custom projects,
- DSM budget as a percentage of utility annual revenue,
- structure and screening of programs including differentiating between market transformation, lost opportunity and enabling activities,
- structure and use of LRAM, SSM and DSMVA,
- process and content of program evaluations including the requirement for a third party audit process,
- length of plan, as well as updating the plan and reporting requirements,
- rules respecting free riders and attribution of energy savings, and
- the appropriateness of directing specific DSM measures to low-income consumers.

Other areas of focus will include the requirement for and role of the Consultative committee, filing requirements for the DSM plans and reporting requirements.

As the content of the topic list indicates, the intent of the proceeding was to streamline processes, harmonize practices where appropriate and re-examine the rules of DSM that had developed to date.

It was not the intent to revisit the general principles adopted and conclusions reached in the Report of the Board E.B.O. 169 III regarding the appropriateness of Demand Side Management being utilized by the Utilities in Integrated Resource Planning (IRP).

In the course of the proceeding, the Board received three settlement agreements. The first was a complete settlement on some of the issues. The other two were partial settlements.

The first partial settlement contained issues that were settled as between EGD and Union on the one hand, and most of the intervenors on the other. Some of the issues in this package dealt with the financial issues and this “financial package” was considered by the parties to be un-severable. That is to say that the parties to this partial agreement regarded each of the elements of the package to be crucial to the package as a whole. Were the Board to disapprove of any discrete element of the package, the package as a whole would be withdrawn, and each of the elements would have to be litigated.

The second partial settlement contained proposals that were agreed to by all intervenors but not the utilities.

The Board held an oral hearing that commenced on July 10, 2006. At the beginning of the oral hearing the Board accepted the completely settled issues as proposed. The oral hearing dealt with the issues contained in the two partial agreements, and other unsettled issues. The oral phase of the hearing, including argument, was concluded on July 28, 2006.

The non-utility parties to the hearing were Canadian Manufacturers & Exporters (“CME”), Consumers Council of Canada (“CCC”), Energy Probe, Green Energy Coalition (“GEC”), Industrial Gas Users Association (“IGUA”), London Property Management Association (“LPMA”), Low Income Energy Network (“LIEN”), Pollution Probe, School Energy Coalition ("SEC") and Vulnerable Energy Consumer's Coalition ("VECC").

The full record of the proceeding is available at the Board's offices. The Board has considered the full record but has summarized it in this decision to the extent necessary to provide context for its findings.

Chapter 2 deals with details of the completely settled issues. Chapter 3 addresses the issues contained in the "financial package". Chapter 4 deals with the remaining issues. Chapter 5 deals with the issues respecting a common set of input assumptions, a common guide and with next steps. In that regard, this decision document is referred to as Phase 1. Appendix 1 contains details regarding some of the procedural aspects of the proceeding, including a list of parties' representatives and witnesses.

CHAPTER 2 - THE SETTLEMENT PROPOSAL

A Settlement Proposal was filed with the Board on July 8, 2006 and was updated on July 11, 2006. The Board heard submissions from the parties and accepted the Settlement Proposal on July 11, 2006.

The Board acknowledges the effort of the participating parties to the Settlement Proposal and is pleased with the significant number of issues that were settled prior to the oral hearing.

Below are the completely settled issues which were accepted by the Board. To provide context to the balance of this decision, the Board sets out below the agreed upon phrasing of the settled issues. The numbering in brackets reflects the numbering that appeared on the Board's approved issues list for the proceeding.

Is a three year plan an appropriate term of a DSM plan? (Issue 1.2)

> "Parties agree that 3 years is an appropriate term for a multi-year DSM plan. Parties agree that the issue of whether and, if so, how a multi-year DSM plan should be aligned with a Utility's Incentive Regulation ("IR") period should be determined by the Board in the context of establishing the IR mechanism and rules, and cannot be determined in this proceeding in the absence of information on the structure and term of the IR regime adopted by the Board."

How are DSM parameters adjusted inside a multi-year rate making process? (Issue 1.6)

Parties referred this issue to completely settled Issue 1.2.

Should budgets, programs, targets, incentives and other plan components be established on an annual or multi-year basis? (Issue 1.8)

> "The approval of multi-year DSM plans will provide the utilities with the certainty of funding for programs which will have forecast life spans of more than one year. DSM plan components will be established at the outset of a multi-year DSM plan with the intention of applying throughout the currency of the multi-plan plan.
>
> As this settlement provides that the budget, SSM mechanism, LRAM, and DSMVA are all developed and measured on an annual basis within a multi-year plan, it is appropriate that amounts be recorded in all DSM variance or deferral accounts on an annual basis (market transformation amounts may be an exception)."

How should the budget be allocated between customer classes in rates? (Issue 1.9)

> "Cost allocation in rates shall be on the same basis as budgeted DSM spending by customer class. This allocation should apply to both direct and indirect DSM program costs."

Should the TRC [Total Resource Cost] test be the only test used to screen measures and/or programs for DSM plans? If no, what other tests should be used and how should these be applied? (Issue 2.1)

> "TRC shall be the only formal screen to determine whether a measure or program can be considered for inclusion in the portfolio. EBO 169-III identified numerous other considerations and tests that could be used to determine which measures and programs are actually selected for the portfolio in any given year, and those considerations and tests should continue to apply."

How should free rider and savings input assumptions be determined? (Issue 3.1)

> "Parties agree that input assumptions such as free rider rates, prescriptive measure savings assumptions, incremental equipment costs, measure lives and avoided costs (natural gas, electricity and water) shall be based on research utilizing the best available data at the time a multi-year plan or new program or significant new program design is developed. These assumptions shall be assessed for reasonableness prior to implementation of the plan or program and should be reviewed and updated on a regular basis during the plan period as part of each Utility's ongoing evaluation and audit processes."

What certainty is required that the assumptions are set for the duration of the DSM plan? (Issue 3.3)

> "The time at which changes in assumptions become effective shall differ depending on the use to which the assumption is being put:
>
> ***Program Design and Implementation.*** The Utilities agree to the principle that their DSM programs should be managed with regard to the best available information known to them from time to time. Normal commercial practice requires that a Company should react through changes to program design, implementation and/or mix, to material changes in base data as soon as is feasible given relevant operational considerations.
>
> ***LRAM.*** Assumptions used will be best available at the time of an audit. By way of example, if in June of 2008 the audit of the 2007 programs demonstrates a change in assumptions, that change shall apply for LRAM purposes from the beginning of 2007 onwards until changed again.

> ***SSM.*** Assumptions used from the beginning of any year will be those assumptions in existence in the immediately prior year, adjusted for any changes in the audit of that prior year. By way of example, if in June of 2008 the audit of the 2007 programs demonstrates a change in assumptions, that change shall apply for SSM purposes from the beginning of 2008 onwards until changed again."

What is the mechanism to determine if an input assumption needs to be reviewed or researched? (Issue 3.4)

> "The Utility may of its own initiative or at the request of the Evaluation and Audit Committee ("EAC") commence a review of or research into assumptions."

How should the (LRAM) mechanism be structured? (Issue 4.2)

> "The parties agree that the LRAM mechanism shall be calculated using the assumptions and savings estimates approved in the plan and adjusted for the audited Evaluation Report results.
>
> For Union, the first year impact will be calculated as 50% of the annual volumetric impact multiplied by the distribution rate for each of the rate classes that the volumetric variance occurred in.
>
> For EGD, the first year impact will be calculated on a monthly basis based on the volumetric impact of measures implemented in that month multiplied by the distribution rate for each of the rate classes that the volumetric variance occurred in.
>
> Both of these processes for the Utilities reflect the status quo.
>
> The LRAM account shall be cleared annually.

> For purposes of clearing LRAM, input assumptions will be adjusted on an annual basis, as a result of the evaluation and audit work completed and shall apply from the beginning of the year being audited. See also Issue 3.3."

What evidence should be submitted to demonstrate that all conditions for clearance have been met? (Issue 4.3)

> "Parties agree that the Utilities shall file an Audit report and any other backup needed to support the volumes used in the LRAM calculation. The Audit report will be prepared by an independent auditor to ensure accordance with Board approved rules. The auditor shall provide an opinion on the LRAM proposed and any amendment thereto. The remainder of the auditor's responsibilities are reflected in Issue 9.3."

Is a third party audit required to verify LRAM calculation prior to clearance? (Issue 4.4)

> "Yes, see issue 4.3 above."

How should LRAM costs be allocated between customer classes? (Issue 4.5)

> "The LRAM shall be recovered in rates on the same basis as the lost revenues were experienced so that the LRAM ends up being a full true-up by rate class."

Should an incentive mechanism be in place? If yes, (Issue 5.1)

> "Yes."

Is a third party audit required to verify year-end SSM calculation? And if required, what should be the audit principles, scope and timeline? (Issue 5.3)

> "Parties agree that an independent auditor shall complete an evaluation audit with the purpose of verifying the claimed financial results and that

> the DSM shareholder incentive amounts (being the SSM and the incentive available in respect of market transformation programs) are calculated in accordance with the Board approved methodology. The audit shall provide an opinion on the DSM shareholder incentive amounts proposed and any amendment thereto. The remainder of the auditor's responsibilities are reflected in issue 9.3."

How should SSM costs be allocated between customer classes? (Issue 5.4)

> "Parties agree that DSM shareholder incentive amounts shall be allocated to the rate classes in proportion to the net TRC benefits attributable to the respective rate classes."

What evidence is required to clear the DSMVA? (Issue 6.4)

> "The utility shall clear DSMVA amounts, subject to review as a component of the DSM audit, to ensure compliance with the Board approved rules. The utility shall include the DSMVA as part of the audit described in issue 9.3. The utility may recover the amounts in the DSMVA from ratepayers provided it has achieved its annual TRC savings target on a pre-audited basis and the DSMVA funds were used to produce TRC savings in excess of that target on a pre-audited basis."

How should DSMVA balances be allocated between customer classes? (Issue 6.5)

> "The Utilities shall allocate the DSMVA amounts in rates based on the Utility's DSM spending variance for that year versus budget, by customer class. The actual amount of the variance versus budget targeted to each customer class shall be allocated to that customer class for rate recovery purposes."

Should the DSM consultative be continued? If yes, (Issue 7.1)

> “When required or useful, the utility will engage and seek advice from a variety of stakeholders and experts in the development and operation of its DSM program. As the utility is ultimately responsible and accountable for its actions, consultative activities shall be undertaken at its discretion. However, at a minimum, each utility will hold two consultative meetings annually. The purpose of the meetings will be to:
>
> - Review annual results (the Evaluation Report will be sent to the Consultative annually for review) and select the Evaluation and Audit Committee (“EAC”). Three members will be selected using the current process used to select the Audit Sub-Committee; the fourth member will be the utility. In the current process, the members of the Consultative nominate individuals to stand on the committee. Then each member of the Consultative votes for the three members they would like on the committee. The three with the highest number of votes form the committee.
>
> - Review the completed evaluation results.
>
> The Utilities each acknowledge the principle that stakeholder consultation has proved valuable. They each intend to continue to take advantage of the input of the consultative as long as the consultative is adding value and the overall cost of the process is reasonable.”

What role should the Consultative have in the DSM planning, design, approval and audit process? (Issue 7.2)

Settlement on this issue was referred to completely settled Issue 7.1.

How often should the Consultative and LDCs meet? (Issue 7.3)

> "A utility shall determine the stakeholders that it will engage based on the goals and objectives of the engagement, subject to the requirement to meet twice annually set out under Issue 7.1 above. See Issue 7.5."

What is the appropriate amount that should be budgeted for Consultative and Sub-committee expenses? (Issue 7.4)

> "The utility shall determine as part of the planning process, the appropriate amount to include in its overall DSM budget for stakeholder engagement, based on anticipated needs."

How should participation in the Consultative committee be determined? (Issue 7.5)

> "The utility shall determine the stakeholders that it will engage based on the goals and objectives of the engagement. All intervenors in the Utility's most recent rate case shall be entitled to participate in the consultative meetings described in issue 7.1 above."

Should a percentage of the DSM budget be allocated to research? If yes, (Issue 8.1)

> "Parties agree that the Utilities should conduct forward-looking DSM research. The appropriate level of budgets for research shall be determined by each Utility from time to time (depending upon need, market conditions, etc.) and each Utility should include a summary of its forecasted research in its multi-year DSM plan filed with the Board."

How should it be determined that research is required and when? (Issue 8.2)

> "The utility shall determine the research needed to inform program assessment as part of its ongoing operational responsibilities and to ensure the long term viability of its DSM program. In making this

> determination, the Utility shall give due consideration to any recommendations of the EAC, the Auditor, and the consultative."

To reduce duplication, should certain research commitments be combined for both LDCs? (Issue 8.3)

> "Each Utility shall be responsible and accountable for its research activities and expenses. The utility is expected to seek and leverage efforts with third parties where appropriate but it is recognized that unique circumstances and objectives may exist that preclude partnering in some instances."

How often should a DSM market potential study be conducted by the LDCs? (Issue 8.4)

> "Market potential studies, or updates to an existing study, must be filed by each Utility together with its multi-year plan. The Utility may, in its discretion, do additional studies of market potential or updates during its plan."

What is the purpose of evaluation reports and what should they contain? (Issue 9.1)

> "EGD and Union are accountable to the Board to develop and implement cost effective DSM programs including the monitoring and evaluation of results. In order to inform stakeholders on the activities and results of the DSM programs undertaken, the utility shall file annually, a clear and concise Evaluation Report that summarizes the savings achieved, budget spent and the evaluations conducted in support of those numbers.
>
> It is the purpose of the evaluation and audit process to review all input assumptions related to the delivery of DSM over the period of the multi-year plan. To assist with that purpose, the parties propose the establishment of an EAC to engage stakeholders in the development of an

evaluation plan and budget and to engage stakeholders in a review of the evaluation results as they become available over the term of the plan."

Is a third party audit of the evaluation report required? And if required, what should be the audit principles, scope and timeline? (Issue 9.3)

"The parties agree that a third party audit of the Evaluation Report is required. The auditor will be retained by the utility who determines the scope of the audit. It will be the role of the auditor to:

- Provide an opinion on the DSMVA, SSM and LRAM amounts proposed and any amendment thereto
- Verify the financial results in the Evaluation Report to the extent necessary to give that opinion
- Review the reasonableness of any input assumptions material to the provision of that opinion
- Recommend any forward looking evaluation work to be considered

The auditor shall be expected to take such actions by way of investigation, verification or otherwise as are necessary for the auditor to form their opinion. The auditor, although hired by the utility, must be independent and must ultimately serve to protect the interests of stakeholders."

Should there be an Audit Sub-committee with intervenor participation? And if yes, what role should the Audit Sub-committee have? (Issue 9.4)

"As described in Issue 9.3 above, parties agree that there should be an audit subcommittee entitled EAC. Participation in the EAC will be determined as set out in Issue 7.1.

The EAC will provide formal input into the evaluation plan. In regards to evaluation activities the EAC will continue to have an advisory role in the following:

- Consultation prior to the filing of the DSM plan on evaluation priorities for the next three years (or the duration of the multi-year plan). The utilities will, as part of their implementation plan, review all of the input assumptions over the course of each multi-year plan.
- Review and comment on evaluation study designs. Input on the research methodology used to determine the input assumptions.
- Reviewing the scope and results of evaluation work completed on new programs introduced over the course of the multi-year plan.
- Selection of the independent auditor to audit the Evaluation Report and determine the scope of the audit. The EAC will ensure that all comments on the Evaluation Report from the Consultative are reviewed by the auditor.
- Following the audit, review of the Evaluation Plan annually to confirm scope and priority of identified evaluation projects.
- The EAC will be responsible for meeting the reporting guidelines of the Board (found at Section 2.1.12 of the Natural Gas Reporting & Record Keeping Requirements Rule for Gas Utilities). The EAC will provide a final report within 10 weeks from the later of, the receipt of the Evaluation Report and supporting evaluation studies from the Utility, or the hiring of the auditor. Recommendations of the EAC with respect to DSMVA, LRAM and SSM clearances shall be included in the EAC's final report. The EAC shall not consider any further information subsequent to the Board's filing deadline each year."

What characteristics are required to determine that a program is either a market transformation or lost opportunity program? (Issue 10.1)

"Market Transformation programs are those that (a) seek to make a permanent change in the market for a particular measure, (b) are not

> necessarily measured by number of participants and (c) have a long term horizon.
>
> Lost Opportunity programs are those that focus on DSM opportunities that will not be available, or will be substantially more expensive to implement, in a subsequent planning period."

How should it be determined that utility has achieved any prescribed target? (Issue 10.3)

and

What should be the length of a market transformation and lost opportunity program? (Issue 10.5)

and

What is the appropriate level of funding for a market transformation or lost opportunity program? (Issue 10.6)

Settlement on these issues was referred to completely settled Issue 10.7.

How should a program incorporate the following elements; information and education activities; incentives; research; activities to reduce market barriers such as building codes and energy efficiency appliance standards; and coordination with other entities (e.g. OPA)? (Issue 10.7)

> "For each market transformation program the utility should, in its multi-year plan, propose a program description, goals (including measurement method), incentive (including structure and payment), length, level of funding and program elements. Such programs are not amenable to a formulaic approach and therefore should be assessed on their own merits and all of the above components should be suitable given the subject matter and program goals."

Is it appropriate to use DSM funds for fuel switching to natural gas? (Issue 14.1)

> "Fuel switching is an important activity that can help alleviate some of the electricity supply programs faced by the province; however, the utility shall not use DSM funding to promote fuel switching to natural gas. The utility will pursue fuel switching activities as part of its marketing efforts that will be included in its rate case or other suitable application."

Is it appropriate to use DSM funds for fuel switching away from natural gas? (Issue 14.2)

> "Where fuel switching away from natural gas aligns with the Utility's DSM objectives the Utility may pursue these activities."

CHAPTER 3- PARTIAL SETTLEMENT (FINANCIAL PACKAGE)

In addition to the completely settled issues, the Board was presented with a list of partially settled issues. Union, EGD, CCC, SEC, Energy Probe, IGUA, LPMA, and VECC (the "Partial Settlement Proponents") were parties to a complete agreement on a number of issues. Certain of these issues were presented as a package (the "Financial Package") which the parties presented as being un-severable; i.e. if the Board did not accept the entire package, the Financial Package agreement would be withdrawn. The Financial Package dealt with:

- DSM budgets (Issue 1.3),
- DSM plan targets (Issue 1.4),
- allocation of DSM budgets amongst customer classes (Issue 1.7),
- the DSM incentive mechanism (Issue 5.2),
- the DSM variance account (Issues 6.1, 6.2, 6.3),
- market transformation and lost opportunity program budgets and utility incentives related to them (Issues 10.2, 10.4, 10.8), and
- targeted programs for low income customers (Issues 13.1, 13.2, 13.3).

The Partial Settlement Proponents explained that the individual elements of the Financial Package were tied together, and that to change one element would have repercussions on other elements. On the opening day of the hearing, the Board explained to the parties that it would hear whatever evidence the parties chose to lead; however, if at the conclusion of the hearing the Board determined that it did not wish to accept the Financial Package in its entirety, it would not re-open the hearing to hear fresh evidence on any of the issues. The Partial Settlement Proponents subsequently informed the Board that they would continue to exclusively support the Financial Package, and would not present any evidence to be considered in the event that the Board did not accept the entire Financial Package.

In addition to the Financial Package, the Partial Settlement Proponents reached a partial settlement on a number of other issues that could be considered individually. This chapter deals only with the Financial Package; the remaining partially settled issues will be addressed in Chapter 4.

The chief proponents of the Financial Package in the hearing were the utilities through their witness panels. The other Partial Settlement Proponents did not present witnesses in support of the Financial Package, but did conduct what was described as “friendly” examinations of the utility witnesses on these issues. The parties opposed to the Financial Package cross-examined the utility witnesses and, in some cases, filed their own proposals.

The Board will accept the Financial Package as presented by the Partial Settlement Proponents. As the Board explained when considering the meaning of a partial settlement on July 10, the Board has considered all of the issues in the Financial Package on an issue by issue basis. Taken individually and as a whole, the Board finds all of the proposals contained in the Financial Package to be reasonable.

The Board is pleased that the Financial Package amounts to what is largely a “rules-based” approach. Many of the major elements of the three year DSM plans will essentially be locked in for the term of the plan, and will not require further review by the Board during this period. This should result in significant regulatory savings for the parties, the Board, and, ultimately, for ratepayers.

The Board finds that the Financial Package strikes an appropriate balance between advancing DSM forward through higher budgets and ultimately higher TRC savings targets, while not forcing the utilities to try to spend money that they indicated they would have trouble spending in a cost effective manner. The Board is also satisfied that the Financial Package will not cause undue rate impacts to ratepayers given the relatively modest nature of the proposals, in light of the overall revenue requirement of the respective utilities.

In addition to the overall comments above, the Board has the following remarks on the individual issues that comprise the Financial Package.

How should the financial budget be determined? (Issue 1.3)

The Partial Settlement makes the following proposal.

> “Parties in agreement with this partial settlement accept that a DSM budget cap should be developed using the following formulaic approach in each year of a multi-year DSM plan. For the first year, the budget for EGD will be $22.0 million, an increase of $3.1 million or approximately 16% from its 2006 budget. For Union, the 2007 budget will be $17.0 million an increase of $3.1 million or approximately 22% from its 2006 budget.
>
> In the second and subsequent years of a multi-year DSM plan, the DSM budget for each year of the plan will be determined by applying an escalation factor of 5.0% for EGD and 10% for Union to the budget developed for the immediately preceding year. The purpose of the application of different escalation factors for EGD and Union is to address the desire by some parties that the difference between the level of spending by EGD and Union be narrowed. The parties agree that this formula results in budgets of $23.1 million and $24.3 million for EGD in 2008 and 2009 respectively, and budgets of $18.7 million and $20.6 million for Union in 2008 and 2009 respectively.
>
> Parties to this partial settlement agree that the Utilities remain obligated to develop, and spend monies on, cost-effective DSM programs up to the budget amount developed by this methodology.”

The Board is satisfied that the Financial Package proposal reaches an appropriate balance between increasing DSM budgets and approving budgets which can be spent in a cost effective manner. Both Pollution Probe and GEC argued in favour of much higher budgets; however, the Board is not convinced that the utilities could currently spend these amounts cost-effectively.

Should there be plan targets and if so, should they be volumetric or based on TRC values? (Issue 1.4)

The Financial Package agreement makes the following proposal:

> “Parties to this partial settlement further agree that there will be an annual TRC target. The parties agree to phase in a formula over the next three years which will set this target, as described below, by averaging the Utility’s actual audited TRC results over the previous three years and applying to this figure an escalation factor equal to 1.5 times the amount by which the utility’s budget is increased. The parties agree to phase in the aforementioned formula over the next three years beginning with an agreed upon target for each utility in 2007 which, for Union will be $188 million and for EGD $150 million.
>
> Furthermore, the parties agree that, in the event the avoided costs used by the utility are, at a later date, updated, the actual audited results from previous years used to calculate the target will be adjusted to reflect these updated avoided costs.
>
> Finally, and for greater certainty (and as an example), set out below is the formula by which the target will be set for Union, with 2010 provided for illustrative purposes only:
>
> • 2007 - $188 million.
>
> • 2008 - The simple average of $188 million and the actual 2007 audited TRC value as approved by the Board increased by 1.5 times the budget escalation factor (ie. 15%).

- 2009 - The simple average of $188 million and the actual 2007 and 2008 audited TRC values as approved by the Board increased by 1.5 times the budget escalation factor (ie. 15%).

- 2010 - The simple average of the previous three years actual audited TRC values as approved by the Board increased by 1.5 times the budget escalation factor (ie. 15%).

For EGD, the formula by which the target will be set is as follows, with 2010 provided for illustrative purposes only:

- 2007 - $150 million

- 2008 - The simple average of $150 million and the actual 2007 audited TRC value as approved by the Board increased by 1.5 times the budget escalation factor (ie. 7.5%).

- 2009 - The simple average of $150 million and the actual 2007 and 2008 audited TRC values as approved by the Board increased by 1.5 times the budget escalation factor (ie. 7.5%).

- 2010 - The simple average of the previous three years actual audited TRC values as approved by the Board increased by 1.5 times the budget escalation factor (ie.7.5%).

The “actual audited TRC values” shall be the total TRC produced for the year in question as determined by the audit in the following year. In setting the target for 2009 and subsequent years, the actual audited TRC value for the immediately preceding year, but not for the prior two years used in the average, will be adjusted to reflect any changes in input assumptions determined in the audit to apply to that year for LRAM purposes. By way of example, if a free rider rate is increased in the 2009 audit carried out in the first half of 2010, under the partial settlement that change would normally apply to SSM for the years 2010 and thereafter, but to LRAM for 2009 as well. In calculating the target for 2010, the three year average will use the TRC values otherwise determined for 2007 and 2008, but for 2009 will use the audited TRC values, adjusted for that change in free rider rate identified in the audit.”

The Board is satisfied that the Financial Package proposal sets reasonable TRC targets for the utilities. The Board notes that the formula used to derive the targets in years two and three of the plan is self adjusting to account for actual performance in the previous year. The Board finds this formula to be preferable to setting the targets for all three years in advance.

The Board notes that the target for Union in year one of the plan will actually be lower than its Board approved target for 2006. The Board heard evidence from Union that the TRC target for 2006 had been set at a level that it will not attain. Union indicated that according to its current projections for 2006, the company will likely achieve TRC savings in the range of $170 million (on a target of $216 million). The Board accepts Union's evidence in this regard, and finds that a target of $188 million in year one of the three-year plan is reasonable.

On what basis should the DSM program spending be targeted amongst customer classes? (Issue 1.7)

The Financial Package agreement makes the following proposal:

> "Parties acknowledge that EGD's and Union's rate classes and customer needs are not identical, and hence it is not appropriate to restrict spending based on a rigid formulaic approach by rate class. The Utilities acknowledge and accept the principle that their portfolio of DSM programs should provide customers in all rate classes and sectors with equitable access to DSM program(s) to the extent reasonable, and that this principle must be balanced and consistent with the principle of optimizing cost-effective DSM opportunities. To the extent that a proposed multi-year plan proposes DSM sector (ie. residential, commercial, or industrial) level spending that is significantly different than the historical percentage levels of spending in those sectors, the utility will provide its explanation for this in its proposed multi-year plan. Parties may challenge any such

> explanation, or its impacts. The Board will then determine whether to approve the revised spending ratios, and if so, under what conditions.
>
> To the extent that actual sector level spending then varies significantly from the ratios identified in the plan, parties may challenge the appropriateness of the deviation from the plan when the utility seeks approval for the clearance of relevant accounts and the Board can make such order as is appropriate. (Issue 1.7)"

The Board is cognisant of the tension between ensuring that each rate class is allocated an appropriate portion of DSM funds on the one hand, and the benefits of targeting spending to the most cost effective programs regardless of what rate class they fall in on the other. The Board is satisfied that the Financial Package proposal finds the appropriate balance.

What is an appropriate incentive mechanism and how should it be calculated? (Issue 5.2)

The Financial Package agreement makes the following proposal:

> "The parties to this agreement agree that an SSM shall be established for the first year of the plan and shall be in effect for each year of each multi-year plan.
>
> Parties agree that the amount of any SSM shall not be included in the Utility's return on equity ("ROE") for the purposes of setting rates or in the calculation of any earnings sharing amounts.
>
> The parties agree that for the purposes of this settlement, the TRC indexing target for 2007 for EGD will be $150 million, and for Union, $188 million. Targets for subsequent years shall be set in accordance with the formula in Issue 1.4. The cumulative SSM incentive payment to each utility for achieving their respective TRC target will be set by a formula,

and at 100% of TRC target will be $4.75 million. For the purposes of determining whether each utility has met its 100% TRC target, the input assumptions for the calculation of SSM will not be changed retroactively. For clarity, changes to input assumptions, which are confirmed through audit, apply in the year immediately following the year being audited. For example, input assumptions for purposes of the SSM remain fixed for 2007, and any changes to input assumptions which change as a result of the audit of the 2007 results which is undertaken in early/mid-2008 will apply from the beginning of the 2008 year forward. Also see Issue 3.3.

For both Utilities, the following formula applies for the determination of the SSM curve and resulting cumulative payout. The SSM payout will be calculated based on the results as they apply along the curve and each of the following percentage thresholds do not represent lump sum payments for reaching the threshold but simply serve to structure the SSM curve based on targets and SSM amounts as agreed to by the supporting parties:

Up to 25% of the annual target, a total payout of $225,000
Up to 50% of the annual target, a total payout of $675,000
Up to 75% of the annual target, a total payout of $2,250,000
Up to 100% of the annual target, a total payout of $4,750,000
Up to 125% of the annual target, a total payout of $7,250,000
In excess of 125% of the annual target, a total that is capped at no more than $8,500,000.

The parties agree that the annual ‘cap’ of $8.5 million will increase annually by the Ontario CPI as determined in October of the preceding year (i.e., the 2008 cap will increase based on CPI as determined at October of 2007).

See also issue 10.4 for the incentive available to the utilities in respect of market transformation programs”

During the hearing, the utilities provided the formula in calculating SSM, which is reproduced below:

> “For achievement of between 0 and up to 25.0% of the annual target, the SSM payout shall equal $900 for each 1/10 of 1% of target achieved.
>
> For achievement of greater than 25.0% up to 50% of the annual target, the SSM payout shall equal $225,000 plus $1,800 for each 1/10 of 1% of target achieved.
>
> For achievement of greater than 50.0% up to 75.0% of the annual target, the SSM payout shall equal $675,000 plus $6,300 for each 1/10 of 1% of target achieved above 50.0%, and
>
> For achievement of greater than 75.0% of the annual target, the SSM payout shall equal $2,250,000 plus $10,000 for each 1/10 of 1% of target achieved above 75.0% to a maximum of the SSM annual cap.”

There was a complete settlement on issue 5.1, in which all parties agreed that there should be an incentive mechanism. The Financial Package proposal for issue 5.2 presents a formula for determining the exact amount of the SSM payout based on the level of success each utility has achieved in hitting its TRC targets. The Financial Package proposal calls for an escalating incentive scale which starts at the first dollar of TRC net benefits achieved. This proposal marks a change from the current Board approved practice where the utilities are required to reach a certain level of net TRC savings before any incentive is realized. The Board is satisfied that this change to the *status quo* is appropriate. The Board is persuaded by the utilities’ evidence that the proposed structure is more likely to attract management attention to DSM programs. The Board is also comforted by the fact that the incentive payments for performance below 50% of the TRC target is very low. Further, the $8.5 million cap on incentive payments for any one year ensures that ratepayers will not have to pay an undue amount if a utility achieves extraordinary success.

Demand Side Management Variance Account (Issues 6.1, 6.2, 6.3)

The Financial Package agreement makes the following proposals:

> “Parties agree that the DSMVA shall be continued. The DSMVA shall be used to “true-up” the variance between the spending estimate built into rates for the year and the actual spending in that year. If spending is less than what was built into rates, ratepayers shall be reimbursed. If more is spent than was built into rates, the utility shall be reimbursed up to a maximum of 15% of its DSM budget for the year. All additional funding must be utilized on incremental program expenses only (i.e. cannot be used for additional utility overheads). For greater certainty, program expenses include market transformation programs. ”
>
> “There should be no limit on the amount of under spending from budget that should be returned to ratepayers. Parties agree that a Utility may spend and record in the DSMVA for reimbursement to the utility, in any one year, no more than 15% (fifteen per cent) of that Utility’s DSM budget for that year. ”

The Board finds the Financial Package proposal to be reasonable. The DSMVA will allow utilities to aggressively pursue programs which prove to be very successful, even where this causes them to exceed the Board approved budget (by up to 15%). It will also ensure that unspent DSM funds are returned to ratepayers.

Market Transformation (Issues 10.2, 10.4, 10.8)

The Financial Package agreement makes the following proposals:

> “Every utility DSM plan should include an emphasis on lost opportunity and market transformation programs and activities. For purposes of this agreement, parties agree that this emphasis will consist of a market transformation budget of $1.0 million per utility per year and is included in the total budget amounts referenced in issue 1.3.”
>
> “Parties agree that each utility is entitled to an incentive payment of up to $0.5 million in each year of the multi-year plan based on the measured success of market transformation programs. The measurement and calculation methodologies to determine whether this amount has been earned in the year shall be detailed by each utility in its multi-year DSM plan. For clarity, this amount is in addition to any amount earned at issue 5.2. By way of example, a Utility may propose in its DSM plan a program to increase the market share of a particular high efficiency product, and a $250,000 annual incentive based on the market share of that product at the end of each year, measured by a specific third party market index, being 10% higher than the previous year. If the DSM plan is approved by the Board including that program, the Utility will be entitled to a $250,000 incentive in each year that it meets the stated market share goal.”
>
> “For each market transformation program the utility should, in its multi-year plan, propose a program description, goals (including measurement method), incentive (including structure and payment), length, level of funding and program elements. Such programs are not amenable to a formulaic approach and therefore should be assessed on their own merits and all of the above components should be suitable given the subject matter and program goals.”

The Board is satisfied with the Financial Package proposal for market transformation. GEC argued for a much larger budget for market transformation and lost opportunity projects. Utility witnesses stated that the utilities could not effectively spend these budgets. The Board notes that the proposal regarding utility incentives for these programs does not achieve the level of certainty that exists for other elements of the Financial Package. While GEC argued for a more concrete incentive mechanism, the witnesses at the hearing were largely in agreement that market transformation programs are not necessarily amenable to fixed and inflexible rules. The Board agrees. The Board therefore accepts the proposal as filed.

Targeted Programs (Issues 13.1, 13.2, 13.3)

The Financial Package agreement makes the following proposals:

> “Parties to this settlement accept that low-income customers face barriers to access DSM programs which are unique to this group of customers. Accordingly, parties to this settlement agree that it is appropriate to establish a minimum amount of spending on targeted low-income customer programs in the residential rate classes of both Utilities. It is agreed that each utility will spend out of its DSM budget a minimum of $1.3 million, or 14% of each respective utility’s residential DSM program budget, whichever is greater. For clarity, a utility may expend more than $1.3 million or 14% of its residential DSM program budget if the utility considers it appropriate. The Utilities each agree to increase the $1.3 million spending floor by the budget escalation factor appropriate for the utility (i.e. EGD 5%; Union 10%) in each of the second and third years of a three year plan.
>
> The parties to this settlement further agree that of the $1.0 million budget for market transformation programs, each utility will expend no less than 14% on targeted low-income market transformation programs.

> The Utilities agree that by the establishment of this spending level floor, they will not, as a result, reduce planned DSM spending in other rate classes or sectors which are directed at low-income residents (e.g. social housing multi-unit residential spending) or their spending on fuel switching targeted to low-income customers."
>
> "Each of the utilities is at liberty to develop appropriate eligibility criteria for low income residential programs, and each utility agrees to consult with VECC in respect of the development of eligibility criteria and low-income program parameters. Parties to this settlement generally accept that criteria presently used by various levels of government for the purposes of determining low income eligibility may be appropriate for use by the utilities."

The only customer segment proposed to the Board for targeted programs were those for low-income customers. The Board finds the Financial Package proposal to be reasonable. The proposed spending floor should ensure that low-income consumers have access to DSM programs at least in approximate proportion to their percentage of residential revenue. LIEN argued that spending on low-income DSM programs should be equal to 18% of the total residential class DSM budget, assuming the total DSM budget is split proportionately amongst all rate classes. Under Issue 1.7, the Board has already stated its acceptance of budget allocations that are not strictly proportional to customer class revenue. There was conflicting evidence in the hearing as to the estimated proportion of low-income households within the residential sector. LIEN argued that the proportion was 18% while the Partial Settlement proponents argued that 14% was closer to the actual proportion. The Board finds LIEN's evidence on this matter unconvincing and finds that 14% is supported by the evidence. The Board, therefore, accepts the proposal that each utility will annually spend 14% of the residential DSM budget or $1.3 million on low-income programs, whichever amount is greater.

CHAPTER 4 - REMAINING NON-SETTLED ISSUES

The previous chapter, Chapter 3, dealt with the settled issues and the partially settled issues that were presented to the Board as a “financial package”. The following chapter, Chapter 5, includes discussion of Issue 3.2 relating to the question of whether there should be a common guide. This chapter, Chapter 4, deals with the remaining non-settled issues that were addressed during the oral hearing.

What should be the timing of the schedule for submitting and reviewing Demand Side Management (“DSM”) plans? (Issue 1.1)

The Board was presented with a partial settlement. All intervenors agreed as follows:

> “…DSM plans should be filed at least nine months prior to the plan period to which they relate, to give sufficient time for stakeholders and the Board to consider them, and for Board approval prior to the plan period commencing.”

The utilities believe that filing the DSM plans four months in advance of the initial plan year will allow sufficient time to have the plan in place by the beginning of the following year. The utilities indicated that this would allow them to file final results from the previous year’s audit, rather than interim un-audited results.

For clarity, the timing issue here relates to future DSM plans. The timing of filing for the inaugural three-year plan is dealt with elsewhere in this decision.

The Board notes that a filing date at least nine months in advance would entail the presentation of un-audited performance of the plan’s second year. This may likely involve updates once the results are audited. The Board is of the view that updates should be avoided where possible, as they are generally not conducive to an efficient review. While the Board anticipates that a four month time frame will likely be adequate to accomplish the review given the rules approach adopted by the Board, there is the possibility that it will not. In that case, the consequence is a start date that may not immediately follow the last day of the previous term of the plan. While this may not be desirable, it would be of little adverse consequence as the previous plan would continue. It is in the Board's view a reasonable risk to take in order to obtain the benefits of an efficient review. The Board therefore accepts the utilities' proposals that subsequent plans be filed four months in advance of their commencement.

What process and rules should be available to amend the DSM plan? (Issue 1.5)

There was no settlement (complete or partial) on this issue.

In a response to an undertaking (J2.2), the utilities referenced the preamble of the Partial Settlement which reads

> "For greater clarity, where any settled issue is expressed to continue throughout a multi-year plan, no party to that settlement may seek to re-open that issue with respect to either Utility in any other proceeding prior to the earlier of a) the Board's consideration of the multi-year plan of that Utility, or b) a further hearing on DSM in which the Board has determined that such issue is to be considered "

and stated that

> "… it is the position of the utilities that the Board should amend a multi-year plan during the currency of that plan only in exceptional circumstances. It is expected that with the proposed language, all stakeholders will recognize that any application for an amendment must meet a very high onus to demonstrate undue harm. The intent of the above section is not to provide parties with an opportunity to reopen the framework rules established in this proceeding."

As noted at the oral hearing, no rule can prevent requests for review, or should for that matter. It would not be in the public interest to disallow re-opening of the plan in midstream under any circumstances. At the same time, the purpose of this generic initiative is to avoid unnecessary re-visitation of DSM issues.

Demonstration of “undue harm” was accepted as a reasonable principle by intervenors. The Board concurs that it is a workable principle and useful in the circumstances. There was also support for the proposal by SEC that any party claiming undue harm must first seek leave of the Board before the matter is thoroughly reviewed, and leave should be given only in exceptional circumstances. The Board notes that if a proposed amendment came forward either by way of a motion or by way of application, the Board has the authority and tools to subject the request to the appropriate scrutiny, and to ensure that the intentions of the parties and the Board are respected.

As for the proposal by the utilities that the Board use its cost assessment powers as a further measure to dissuade frivolous requests, this option is always available to the Board and can be used when warranted. This applies equally to intervenors and the utilities.

Should a TRC threshold be established to determine if a measure and/or program is cost effective or should it be based on the cost effectiveness of the portfolio? If so, what should the value be? (Issue 2.2)

The Board was presented with a partial settlement. All parties except SEC agreed as follows:

“The general principle is that all measures and programs should exceed a benefit to cost ratio of 1.0 to be included in the portfolio, but exceptions are reasonable where other benefits are apparent (e.g., pilot programs).”

SEC argued for a screen value of 1.2 rather than 1.0 on the basis that TRC is based on assumptions that change, so it would be appropriate to build in a margin to ensure feasibility. SEC noted that nothing is lost since it appears that there is much more DSM available than the utilities can handle and thus, instituting a higher threshold programs would be better. SEC noted that the exception related to the screen value for pilot programs would still exist.

In the Board's view, the availability of DSM initiatives that exceed the 1.0 cost-benefit ratio is not a compelling argument for deviating from a widely-practiced threshold of 1.0. A program that yields a benefit cost ratio over 1.0 does provide positive net benefits and it would not be appropriate to knowingly forego such benefits. As for SEC's argument that a higher threshold would avoid the risk of uneconomic programs, this can be addressed by instituting more robust input assumptions. Moreover, the risk of uneconomic programs is offset by the fact that, from a societal perspective, the TRC test does not reflect the positive aspects of mitigating negative externalities that are inherent in gas consuming activities. In fact the risk of undertaking uneconomic programs is self-correcting by the incentive by the utilities to maximize rewards by maximizing TRC benefits. For the above reasons, the Board does not accept SEC's suggestion.

However, the Board notes that the partial settlement refers to pilot programs as an example of programs where an exception to the threshold of 1.0 may be permitted. The implication is that there may be other types of programs. No other examples were provided. The Board prefers more certainty as to the exceptions in these circumstances. The Board therefore finds that the exception to the TRC threshold should be restricted to pilot programs at this time.

How often should avoided gas costs be calculated and should the Local Distribution Companies ("LDCs") use identical avoided costs? (Issue 3.5)

There was no settlement (complete or partial) on this issue.

EGD undertook to explore if the utilities could produce a common set of avoided costs and responded (J2.4) as follows:

> “Each Utility will calculate avoided costs for natural gas, electricity and water that reflect the cost structure and service territory of the Utility. In order to ensure consistency, a common methodology will be used to determine the costs. The Utilities will coordinate the timing for selecting commodity costs so that they are comparable.
>
> The avoided costs will be submitted for review as part of the multi-year plan filing and should be in place for the duration of the plan. The commodity portion of the avoided costs will be updated annually.
>
> As avoided costs are long term projections, updating the costs, other than the commodity costs, on a three year cycle should not cause benefits to be significantly under or overstated. Regardless of how often the avoided costs are updated, the same avoided costs will be used to calculate both the target (relative to 2007) and incentive amount, therefore it is anticipated that the relative impact would be minimal.”

Only GEC argued against the utilities’ proposal. It argued that the utilities should use common values for gas commodity, electricity and water. With respect to the avoided distribution system costs (e.g. pipes and storage etc.) which may vary by utility, GEC submitted that the utilities should be required to demonstrate how different these values are so that the Board can determine whether or not the difference is material.

The Board does not accept GEC’s proposals. Avoided gas costs are a significant component of calculating TRC benefits. Gas costs can be different for each utility depending on, among other things, its gas supply management policies and practices.

With respect to system costs, these are certainly unique to each utility and they too are an important part of the TRC benefit calculation. The benefits of estimating and measuring with more precision the TRC values for DSM programs outweigh, in the Board's view, the costs of the incremental effort to determine and review the different values for gas commodity and system costs.

The Board also notes that the methodology for estimating the values for natural gas commodity, system costs, electricity and water will be common for the two utilities, which will ensure some measure of consistency and efficiency.

The Board accepts the utilities' proposals.

Should the LDCs be entitled to revenue protection? (Issue 4.1)

The Board was presented with a partial settlement on this issue. All parties except CME agreed that the utilities should be entitled to revenue protection.

By accepting the "financial package" settled issues earlier in this decision, the Board has not found merit in CME's argument that the utilities should not be entitled to revenue protection. As long as a utility's fixed costs are not fully recovered through fixed charges (and part of the fixed costs are therefore being recovered through the variable charges), there is an inherent conflict for the utility between sales growth and conservation. The existence of a mechanism to neutralize this conflict through an LRAM mechanism is therefore essential to the success of DSM.

What is the appropriate level of funds that should be budgeted for an evaluation report and audit? (Issue 9.2)

The Board was presented with a partial settlement on this issue. All parties except GEC agreed as follows:

"The Utilities shall ensure that DSM budgets and spending include adequate funding to complete the required annual evaluation and audit activities. The utility is responsible and accountable to ensure that evaluation and auditing activities are concluded in a timely fashion and that the associated costs are reasonable."

GEC argued that 3% of the DSM budget should be allocated to evaluation and audit over the three year period. GEC noted that the utility should have the flexibility to move spending between years to balance the lumpiness of spending. GEC noted that this budget should only be spent if required.

The Board fails to see the rationale or benefit of GEC's suggestion. In fact the Board only sees lost DSM program opportunities as the utilities will not be able to access any unspent portion of a fixed budget reserved for evaluation and audit. The Board does not accept GEC's proposal. The utilities should be spending in evaluation and audit as required and as prudent.

What attribution rules or principles should be applied to jointly delivered DSM programs? (Issue 11.1)

There was no settlement (complete or partial) on this issue.

The issue for the parties was how the framework rules will deal with situations where a utility operates or participates in a program with a non-rate-regulated third party and, where this occurs, how should the determination of the TRC benefits be made. For completeness, the Board also makes a finding on attribution between Board rate-regulated parties.

The utilities advocated the centrality principle, as decided by the Board in EGD's EB-2005-0001 rate case. Under the centrality principle, it would be considered that the utility played a central role if the utility initiated the partnership, initiated the program, funded the program, or implemented the program. In such circumstances the utility would be entitled to 100% of the TRC benefits.

Where the utility's role is not considered central, the utilities differed. EGD advocated a scaled role approach, whereas Union proposed that the attribution of TRC benefits would be measured by free ridership. In Union's view, there is no material distinction in the two approaches as both would likely produce the same result. The utilities agreed that it should be the same arrangement for both as determined by the Board.

In the view of CCC and GEC, the rule of centrality is not particularly helpful at avoiding the need to analyze each project or proposal.

The Board notes that the utilities did not dispute the suggestion that attribution of benefits for jointly delivered DSM programs must be done on a case-by-case basis. The Board agrees that this is a reasonable approach. The issue is whether the centrality principle should be maintained.

The Board recognizes that it accepted the centrality principle in the EB-2005-0001 rate case when it dealt with EGD's EnerGuide for Houses program. What makes the re-assessment necessary is the fact that this is a generic hearing for the gas distributors and it is appropriate to review the rules *de novo*. In that regard, the Board notes that, pursuant to the settled and approved issues, there is now a delineated role for the evaluation and audit committee in respect of programs pursuant to the settlement agreement and the Board's acceptance of the agreement. Specifically, the attribution rules set by the Board will be used by the evaluation and audit committee to assess and settle the TRC savings attributable to the utility's role, which will ultimately be reviewed by the Board.

As the utilities concede, the centrality rule is not absolute. There can be considerable judgment in determining whether or not the role of the utility is central in a particular program. Attribution on the basis of the utility's participation that is considered incremental to the program on the other hand appears to remove some of the controversy, and it does not preclude full 100% attribution to the utility. However, a drawback is that the incrementality approach may not adequately and fairly capture situations where a program would not have existed at all if it were not for the utilities.

On balance, the Board accepts the centrality principle for purposes of the first multi-year DSM plans, under which the utility would be entitled to 100% of the TRC benefits if it can be demonstrated that it has a central role in a program. That is, as the utilities proposed, if the utility initiated the partnership, initiated the program, funded the program, or implemented the program. The experience to be gained over the next three years will inform as to the suitability of continuing with this approach after that point.

This leaves the difference in approach by the two utilities where centrality is not claimed or demonstrated.

The Board accepts the utilities' position that the distinction between their approaches is without a difference. The utilities' differences reflect different internal practices, as noted by the utilities. The utilities acknowledge that either approach would involve the evaluation of attribution of each program by the evaluation and audit committee, and ultimately by the Board. However the utilities accept that there should only be one common approach, to be determined by the Board.

The Board prefers the free ridership approach advocated by Union as this would be more consistent with the general approach for measuring TRC benefits in other DSM activities implemented by the utilities.

The TRC benefits for program partnerships with Board rate-regulated entities (e.g. electricity distributors) shall be allocated in the manner indicated in the electric TRC Guide, as was canvassed at the oral hearing. That is, a gas distributor partnering with an electricity distributor shall claim all of the benefits associated with the gas savings.

How should existing or future carbon dioxide offset credits be dealt with in DSM plans and programs, if at all? (Issue 11.2)

The Board was presented with a partial agreement on this issue. All intervenors agreed as follows:

> “Until the rules are known, a deferral account should be established for each Utility and any dollar amounts representing proceeds from the sale or other dealings in credits should be credited to that account”.

The utilities submitted that until the rules of carbon dioxide offset credits are known, the Board should not make any determination on this issue.

The Board accepts the argument by certain intervenors that there is no harm in ordering a deferral account to capture any future carbon dioxide offset credits. While the matter could wait until the resolution, if any, of the carbon dioxide offset credits matter, the utilities did not present convincing arguments to counter the no harm proposition advanced by many intervenors. The Board is generally reluctant to authorize the establishment of deferral accounts without a more concrete and immediate need. However since this matter is within the scope of DSM, there is an opportunity to deal with it now without the need for further processes. Therefore the Board concludes that the establishment of a deferral account would be a reasonable approach in the circumstances, and so orders.

Should free riders for custom projects be determined on a portfolio average or on a project basis? (Issue 12.1)

There was no settlement (complete or partial) on this issue.

The utilities proposed that the free ridership rate should be determined on a portfolio average basis. The single free ridership rate would apply across a number of technologies and a number of sectors. The utilities proposed a free ridership rate of 30%.

VECC submitted that although the fairest way to address attribution for custom projects would be on a project-by-project basis, a portfolio average approach can be acceptable for administrative efficiency, but with the conditions that there should be emphasis on sector-by-sector as suggested by LPMA.

The Board sees merit in the notion of differentiated free ridership rates by market segment, at least for large and small enterprises. However, this is a significant undertaking. The utilities revealed that at present there are over one thousand custom projects within EGD and a fifth of that within Union. A segmentation analysis would need to be done on a sample basis, statistically justified, and reviewed by the parties and the Board. Ordering such studies for the two utilities for this plan may jeopardize the timetable of filing and implementing the respective DSM plans. The Board also notes the testimony by Union's witness that any differences in free ridership rates through market segmentation may at the end balance out and in fact support a single rate.

For these reasons the Board accepts a portfolio average approach for custom projects. The free ridership rate for custom projects will be determined as part of the process that will determine the input assumptions.

For the next generation multi-year plans, the Board expects the utilities to propose common free ridership rates for custom projects that are differentiated appropriately by market segment and technologies.

Should custom projects have a third party or an internal audit and if so, what would be the audit scope and process of the audit? (Issue 12.2)

The Board received a partial settlement on this issue. All intervenors agreed as follows:

> "Custom projects should be audited using the same principles as any other programs. Audit activities should be sufficient for the auditor to form

> an opinion on the overall SSM, LRAM and DSMVA amounts proposed in the Evaluation Report."

EGD proposed that the custom projects be audited as part of its portfolio results based on a significantly appropriate representative sample. The auditor would then confirm the results and these would be included for the purposes of calculating SSM and LRAM, consistent with the completely settled Issue 3.3.

Union proposed that, as custom projects form a large part of Union's DSM portfolio, they should be assessed by a third party, and noted that this is in fact Union's current practice. Union explained that a statistically significant sample of both the largest and smallest subset of projects should be evaluated by a third party evaluator, hired by the utility. The evaluator would not be the auditor because of the particular technical expertise required to review custom projects. The report of the technical expert would form part of the evaluation report, which would be forwarded to the auditor.

The Board notes that the distinction between the Union and EGD proposals is that, in Union's case, the third-party evaluator does the statistical sampling and the initial review of the project before they form part of the evaluation report that is forwarded to the auditor. In EGD's case, that first cut is done in-house but EGD still engages a third party to do an evaluation of the sampling of its custom projects. Although in both cases the results would be forwarded to the auditor for review, the Board is of the view that a common approach should be adopted for the two utilities. The Board prefers Union's current practice where the third-party evaluator does the statistical sampling and the initial review of the project before they form part of the evaluation report that is forwarded to the auditor.

Union proposed the adoption of the rule in the TRC handbook for electric CDM, where the projects selected for assessment should consist of a random selection of 10% of the large custom projects representing at least 10% of the total volume savings for all custom projects and consist of a minimum number of five projects. The Board adopts this proposal, which shall apply to both utilities.

[With respect to custom projects], how should savings be determined and what documentation is required? (Issue 12.3)

The Board received a partial settlement on this issue. All intervenors agreed as follows:

> "Assumptions used should comply with the principles set out under Issue 3.3. Assumptions with respect to measure life should reflect actual expected measure life, so for example should include a factor for the possibility that a measure will not be used for its entire engineering life (due to bankruptcy, change in operations, etc.)."

During the hearing, a complete settlement was considered to have been reached by all parties by truncating the text as follows:

> "Assumptions used should comply with the principles set out under Issue 3.3. Assumptions with respect to measure life should reflect actual expected measure life."

The Board concurs with the settlement.

[With respect to custom projects], should the volumetric savings recorded be actual or forecasted volumes and what documentation is required to verify this result? (Issue 12.4)

In the Partial Settlement, parties referred this issue to Issue 12.3, which in turn was considered to have settled by the parties during the hearing.

The Board approves this settlement.

[With respect to custom projects], how will an appropriate base case be determined? (Issue 12.5)

The Board was presented with a partial settlement on this issue. All intervenors and Union agreed as follows:

> “Only the part of the project that the Utility influenced is to be counted for SSM or LRAM purposes.”

The Board notes that only EGD opted out on the basis that it does not know the implications of the word “influence”. The Board is not in a position to provide assistance to EGD in this regard as EGD itself was not clear as to the relief that it is seeking. However, the Board’s findings in this decision taken in their entirety should help alleviate EGD’s concerns. In particular, the Board does not see how the proposed wording would invalidate settled Issue 3.3, which is EGD’s stated concern.

The Board accepts the partial settlement on this issue.

How should the funding levels and targets, if any, for the gas utilities’ electricity to natural gas fuel switching programs be determined? (Issue 14.3)

The Board was presented with a partial settlement on this issue. All intervenors agreed as follows:

> “Programs promoting fuel switching to natural gas, which should be funded from the marketing budget of the Utility, should, just as with DSM programs, seek to balance maximization of TRC benefits with minimization of rate impacts.”

Union noted that that all parties agreed that fuel-switching to natural gas is not a DSM activity (and DSM funds should not be used for this purpose) and fuel-switching away from natural gas may be appropriate in certain circumstances and may therefore constitute DSM. Union stated that it is simply seeking guidance from the Board or approval to bring an application in the future which will address the issue of the appropriate level of funding, as well as the target, if any, associated with fuel-switching, and thus how success ought to be measured.

EGD submitted that in accepting the completely settled issues in this matter, the Board has effectively deferred the issue to a future panel of the Board that will consider it in the context of whatever proceeding any fuel-switching budget is brought forward.

In this Board Panel's view, making findings, providing guidance or even commenting on the substantive matters of fuel switching would not be appropriate. In making this finding, the Panel was mindful of the impact any conclusions may have on a future panel of the Board. Equally important, there was an insufficient evidentiary basis in this proceeding for the consideration of limiting fuel-switching to a TRC test only. Parties that believe that a TRC test should be used for a fuel-switching budget will have the opportunity to raise this issue in future rate proceedings.

What is the appropriate role of gas utilities in electric CDM? (Issue 15.1)

There was no settlement (complete or partial) on this issue.

EGD submitted that it would like to have the flexibility to make its expertise in DSM available in the electric Conservation and Demand Management (CDM) arena. It also stated that it was not planning to engage in CDM consulting. Union stated that it does not plan to engage in electric CDM. However, Union supported EGD's submissions.

SEC stated that on the assumption that the utilities can engage in electric CDM activities under the Undertakings given to the Lieutenant Governor in Council (the "Undertakings"), it supported the idea that the gas utilities be able to do joint programs with the electric LDCs, as this would tend to lower costs for the gas utilities. SEC cautioned against diverting the gas utilities' attention from gas DSM programs to electric CDM since the latter is, in SEC's view, more lucrative. CCC noted that there is no like thinking by the two utilities on their role regarding DSM activities and that there is no necessary and rational connection between electricity CDM and the utility DSM programs; therefore, there is a need to impose some constraints on the utilities' activities. CCC also questioned the legality of the gas utilities engaging in these activities without proper dispensation under the Undertakings. GEC submitted that gas utilities should only engage in electric CDM when it enhances gas DSM; otherwise, it would be a competing demand on scarce resources and a distraction from their primary focus. VECC supported co-delivery of DSM and CDM measures as it would reduce program costs, but not on the basis of incremental costing and profit sharing. LPMA and VECC suggested that electric CDM should be considered a non-utility activity for revenue requirement purposes of the distribution business.

EGD responded that it does not need an order or dispensation from the Board to engage in electric DSM. It specifically noted that gas DSM itself already generates electricity TRC savings which are included in the SSM calculations. EGD also stated that CDM is consistent with the objectives set out in the Ontario Energy Board Act to promote energy conservation; the Act does not limit the objective to simply natural gas. Further, this matter was canvassed in the EGD's EB-2005-0001 rate case where the Board approved the 50/50 earnings sharing mechanism for the joint participation in the TAPS electric CDM program.

The Board considers that the regulatory construct in Ontario is the concept of a pure distribution utility. This is manifested in the Undertakings and in the Board's rulings for some time. Gas DSM has remained an activity within the corporate structure of the utility and there is no compelling reason to alter this at this time - neither the utilities nor the intervenors instigated or sought a change with respect to gas DSM.

Recent developments in electric CDM may likely bring opportunities for gas utilities to engage or enhance engagement in this area. EGD has some minor engagements with Toronto Hydro Electric Systems Limited ("THESL"). Union does not appear to have any immediate plans to enter the electric CDM field. EGD, however, is interested in possibly expanding its electric CDM role where it is appropriate to do so.

There appears to be strong support if not consensus that the gas utilities should be permitted to engage in electric CDM if such engagement brings about cost efficiencies and the clear focus of the utility's demand management activities should relate to gas. The concern that attention may be diverted from gas DSM to electric CDM is, in the Board's view, theoretical at this stage. It is not axiomatic that enhanced engagement in electric CDM by the gas utilities will necessarily result in lost opportunities for gas DSM. The two initiatives can co-exist in an optimal and workable fashion. This is especially the case where demand management involves funding initiatives, not infrastructure, which has been the experience thus far.

The Board therefore is not concerned about the gas utilities in their present corporate structure engaging in electric CDM as long as such activities can be reasonably viewed as complementary and ancillary to gas DSM and do not involve investments in infrastructure. An example of that is EGD's involvement with THESL in the TAPS program. In fact, the utilization of the demand management expertise residing in the gas utilities should be viewed positively from a public interest perspective given the well known challenges in the Province's electricity sector. In that regard, engagement by the gas utilities in programs aimed at switching from electricity to gas is encouraged.

The concern arises if the gas utilities undertake stand-alone electric CDM activities. That is, programs that are not or do not appear to be synergetic to or enhancing gas DSM, especially if they involved investments in infrastructure on account of electric CDM. This would alter the regulatory construct of a gas distribution utility which would necessitate a review under the Undertakings and the Board's regulatory policies.

The Board is hampered in its assessment of the appropriate role for gas utilities in these situations. The Board is concerned about granting what might be viewed as blanket approval for the utilities to engage in electric CDM activities without knowing exactly what types of activity this might entail. For example, it is not clear if the gas utilities would bid for participation in the recently announced $400 million in OPA funding for electric CDM programs. As noted, the Board would not be concerned about gas utility involvement in OPA-funded programs targeted at switching from electricity to gas. The Board's concerns are in connection with stand-alone electric CDM programs where the gas utilities take on a central role.

This leads to the issue of whether relief from the Undertakings is required for the utilities to engage in electric CDM. EGD's current CDM activities with THESL were approved in EGD's most recent rates case. This program, however, is clearly incidental to EGD's DSM activities and it does not entail a separate infrastructure. EGD is free to continue its relationship with THESL regarding the TAPS program, and either gas utility may engage in similar programs with other electric LDCs where the CDM activity is clearly incidental to the utilities' DSM activities, or to engage in electric CDM stand-alone programs aimed at switching from electricity to gas where no dedicated investment in electric infrastructure would be required.

However, it is certainly possible that some other electric CDM activities or programs would require relief from the Undertakings. The Board is not in a position to articulate these engagements. The Board has not heard sufficient evidence to determine what would be an appropriate involvement by the gas utilities in such circumstances. The Board will leave it to the utilities to make such proposals if they so wish when they come forward with their respective DSM plans.

What is the appropriate treatment of costs and revenues for electric CDM? (Issue 15.2)

and

What incentives, if any, should be paid for electric CDM activities? (Issue 15.3)

There was no settlement (complete or partial) on these issues.

The utilities proposed that the costing of electric DSM should be on an incremental basis and the net revenues be split 50/50 between shareholders and ratepayers. This is the current practice for the TAPS program between EGD and THESL which was approved in the EB-2005-0001 rate case decision.

Some intervenors argued for full costing on the basis that it would avoid concerns about cross-subsidy between gas and electricity ratepayers. Full costing would also lower the net revenues to be split, thereby reducing the utilities' incentive to divert resources from DSM to CDM activities that may be more lucrative.

The Board notes that there was no opposition by intervenors to the institution of the 50/50 net revenue split proposal. The Board accepts the proposal as reasonable.

The utilities' proposal to use incremental costing is not acceptable to the Board. Full costing has been the general practice for programs that are not part of the core utility business and the Board sees no reason to deviate from that practice in this case. Full costing avoids cross-subsidization from gas to electricity ratepayers and reduces the incentive to shift resources from gas DSM to electric CDM in pursuit of possibly more lucrative returns in the latter.

Having approved the incentives contained in the "financial package", the Board does not see the need for other incentives necessary or appropriate for gas utilities to engage in electric CDM activities at this time.

CHAPTER 5 – INPUT ASSUMPTIONS, COMMON GUIDE, AND NEXT STEPS

In this chapter the Board addresses Issue 3.2 which is whether there should be a common guide to specify what input assumptions should be used by the utilities, and deals with the next steps of this proceeding.

Prior to and during the oral hearing the Board indicated that the process of listing and valuing input assumptions would not be part of this phase of the proceeding and that the Board wished to hear from parties on the appropriate subsequent process.

Issue 3.2 was phrased as, should there be a common guide (e.g. TRC Guide for Conservation and Demand Management ("CDM")) to specify what input assumptions should be used by the utilities?

All intervenors agreed as follows:

> "No. The input assumptions should be included in each utility's plan, and should be updated for each Utility during the plan period in accordance with the partial settlement to issue 3.1."

The utilities endorsed the notion of a common list and common values (where appropriate) of input assumptions for the two utilities in a common document. They suggested that this document would be an appendix to a Guide document which would reflect the Board's decision and convert elements of the decision into an operational handbook. They argued that this would be consistent with the intent of the proceeding to develop a rules-based framework for DSM. The utilities further suggested that Board Staff could take ownership of the development of the Guide and become the custodian for future updates.

The utilities argued that the creation of a common document has several advantages. Many of the input assumptions are common and they could be updated in their entirety by a Board process every three years. There would be no question as to the input assumptions that the utilities are to use. Assigning Board Staff the responsibility of updating the input assumptions would impart discipline on parties seeking to change the input assumptions. The utilities noted that where there was a need for different input assumptions between EGD and Union, it would not be difficult to effect within the list.

SEC argued that common input assumptions was a non-issue since the process for amending and updating the assumptions is completely settled in issues 3.1, 3.3 and 3.4 and that the existence of a guide is not relevant to the inclusion or determination of input assumptions. GEC endorsed SEC's view and further argued that an input assumptions process may frustrate the settlement on those issues. GEC further suggested that the Board should rely upon the evaluation and audit process to consider input assumptions. Energy Probe endorsed the submissions put forward by GEC and SEC. LPMA submitted that each utility should include its input assumptions as part of its own plan but the utilities should work together to develop common input assumptions where appropriate. Some argued that translating the Board's decision into a guide amounted to a waste of time, and unless the Board drafted the Guide and handed it to parties in a finished version, parties would take the opportunity to re-argue issues in interpreting the Board's decision.

In the Board's view it is clear that TRC input assumptions will have to be determined before any DSM plans can be finalized. The Board also agrees that the process should be conducted under the Board's review as a second phase to the current proceeding. The Board feels that the most appropriate process for creating the input assumptions guide is one similar to that employed to create the CDM Handbook. The Board therefore directs Board Staff to circulate a draft of an input assumptions guide. Parties will be given an opportunity to comment on the draft and, where they feel it necessary, to make submissions for changes with appropriate support. A Procedural Order will be issued which will set out the details of this process more fully. It is anticipated that this second phase to the proceeding will be completed before the end of 2006.

There are no persuasive reasons in the Board's view not to have a common list of input assumptions and common values with the exceptions of the values as noted in this decision. In fact it appears to the Board that there are efficiencies to be gained by the use of a common set of assumptions. To the extent that there may be differences in how the assumptions might apply to the two utilities or in the values themselves as allowed in the decision, these could be accommodated and highlighted within the generic set. There are only two gas utilities affected and it would not be administratively difficult to do so.

Once the initial list and measures of the input assumptions is determined, the issue then becomes: what is the process for updating these?

The completely settled issue 3.1 stipulates that the input assumptions will be updated on a regular basis during the plan period as part of each utility's ongoing evaluation and audit process. The Board has the ultimate authority to review and approve any changes. It appears to the Board that unless there is joint utility participation, the updates may occur at different times. This would not be efficient and would burden the regulatory process needlessly. The Board therefore concludes that the updating process should be centralized within Board Staff, at least for this first generation of multi-year DSM plans. The Board anticipates that the recommendations that come from the evaluation and audit committee would, in effect, be the substance of the comments process to be employed for the updating of the list and values of the input assumptions. Any suggested updates to the input assumptions guide arising from the evaluation and audit process should be filed with the Board within one month of the end of the annual audit and evaluation. The suggested updates will be considered by the Board, and the guide will be updated if the Board decides it is necessary. Further Procedural Orders may be issued regarding updates to the guide.

The next issue is whether there should be a handbook.

While the Board sees the merits in having a stand-alone handbook, it has concluded that this initiative should not be undertaken at this time. In making this finding, the Board is cognizant of the time sensitivity and significant effort that will be required to develop the common list and measures of the input assumptions and the Board does not wish parties be distracted by the effort to develop a handbook at this time.

The Board will issue a Procedural Order commencing the next phase that will lead into the determination of the input assumptions. The role of Board Staff will be set out in that procedural order. Further Procedural orders will be issued as required from time to time for the Board to receive and rule in this matter and to cause the filing of the multi-year DSM plans by the utilities.

Intervenors eligible for cost awards shall file their cost claims by September 15, 2006. The utilities may comment on these claims by September 22, 2006. The cost award applicants may respond to the utilities' comments by September 29, 2006. Union and EGD shall pay in equal amounts the intervenor costs to be awarded by the Board in a subsequent decision, as well as any incidental Board costs.

Dated at Toronto, August 25, 2006

Original Signed By

Pamela Nowina
Presiding Member and Vice Chair

Original Signed By

Paul Vlahos
Member

Original Signed By

Ken Quesnelle
Member

APPENDIX 1

DECISION WITH REASONS

BOARD FILE NO. EB-2006-0021

PROCEDURAL DETAILS, LIST OF PARTIES AND WITNESSES

PROCEDURAL DETAILS, LIST OF PARTIES AND WITNESSES

THE PROCEEDING

On February 15, 2006, the Board issued a Notice of Application that was published.

The Board issued Procedural Order No.1 on March 2, 2006, establishing the procedural schedule for all events prior to the oral hearing. These events included:

- EDGI and Union evidence filed by April 10, 2006;
- Issues conference on April 24, 2006;
- Issues Day on April 28, 2006;
- Technical Conference to replace interrogatories on EDGI and Union's evidence on May 11 and 12, 2006;
- Intervenor (non-utilities) evidence filed by June 1, 2006;
- Technical Conference to replace interrogatories on Intervenor (non-utilities) evidence on June 8, 2006;
- Half day Intervenor Conference on June 19, 2006;
- Settlement Conference beginning June 19, 2006;
- Settlement Proposal by June 28, 2006; and
- Board review of Settlement Proposal on July 6, 2006.

In response to Procedural Order No. 1, the Board received written evidence prepared by the following parties:

- Malcolm Rowan on behalf of Canadian Manufactures and Exporters ("CME");
- Paul Chernick on behalf of the School Energy Coalition ("SEC");
- Chris Neme on behalf of the Green Energy Coalition ("GEC"); and
- Roger Colton on behalf of Low Income Energy Network (LIEN").

On April 28, 2006, the Board issued Procedural Order No. 2, which established the Issues List for the proceeding.

On June 12, 2006, Procedural Order No. 3 was issued as a result of there not being adequate time to complete the questions on CME evidence within the one day Technical Conference. The Board ordered CME to provided written responses to SEC and GEC questions.

Procedural Order No. 4, issued June 28, 2006, provided the parties with an extension to file a Settlement Proposal with the Board.

PARTICIPANTS AND REPRESENTATIVES

Below is a list of participants and their representatives that were active either at the oral hearing or at another stage of the proceeding. A complete list of intervenors is available at the Board's offices.

Union Gas Limited ("Union")	Crawford Smith
Enbridge Gas Distribution ("EGD")	Dennis O'Leary
Board Counsel and Staff	Michael Millar Michael Bell Stephen McComb
Canadian Manufacturers & Exporters ("CME")	Brian Dingwall

Consumers Council of Canada (“CCC”)	Robert Warren
Energy Probe	Norm Rubin
Green Energy Coalition (“GEC”)	David Poch
Industrial Gas Users Association (“IGUA”)	Vince DeRose
London Property Management Association (“LPMA”)	Randy Aiken
Low Income Energy Network (“LIEN”)	Juli Abouchar
Pollution Probe	Murray Klippenstein
School Energy Coalition (“SEC”)	Jay Shepherd
Vulnerable Energy Consumer’s Coalition (“VECC”)	Michael Buonaguro

WITNESSES

There were 11 witnesses who testified at the oral hearing. The following EGD and Union employees appeared as witnesses at the oral hearing:

<u>EGD</u>

Susan Clinesmith	Manager, Business Markets
Norman Ryckman	Group Manager, Business Intelligence and Support
Michael Brophy	Manager, DSM and Portfolio Strategy
Patricia Squires	Manager, Mass Markets and New Construction Market Development

<u>Union</u>

Chuck Farmer	Director, Market Knowledge and DSM
Tracy Lynch	Manager, DSM

In addition, EGD called the following witness:

Dr. Daniel M. Violette	Principal and Founder, Summit Blue Consulting

Witnesses called by intervenors at the oral hearing:

Chris Neme (By GEC)	Director of Planning and Evaluation, Vermont Energy Investment Corporation
Malcolm Rowan (By CME)	President, Rowan and Associates Inc.
Roger D. Colton (By LIEN)	Consultant, Fisher, Sheehan & Colton

In addition, CME called the following witness:

Anthony A. Atkinson	School of Accountancy, University of Waterloo

K7.1

Ontario Energy Board

Commission de l'Énergie de l'Ontario

Ontario

RP-2002-0158

IN THE MATTER OF APPLICATIONS BY

UNION GAS LIMITED

AND

ENBRIDGE GAS DISTRIBUTION INC.

FOR

A REVIEW OF THE BOARD'S GUIDELINES FOR ESTABLISHING THEIR RESPECTIVE RETURN ON EQUITY

DECISION AND ORDER

2004 January 16

Ontario Energy Board
FILE No. EB-2006-0034
EXHIBIT No. K7.1
DATE February 6, 2007
08/99

Ontario Energy
Board

Commission de l'Énergie
de l'Ontario

Ontario

RP-2002-0158 1

EB-2002-0484

IN THE MATTER OF the *Ontario Energy Board Act*, 1998, S.O.1998, c.15, Schedule B; 2

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, transmission, distribution, and storage of gas; 3

AND IN THE MATTER OF an Application by Enbridge Gas Distribution Inc. for an Order or Orders approving or fixing just and reasonable rates and other charges for the sale, transmission, distribution, and storage of gas; 4

AND IN THE MATTER OF an Application by Enbridge Gas Distribution Inc. and Union Gas Limited for a review of the Board's Guidelines for establishing their respective return on equity. 5

BEFORE: 6

Paul Vlahos 7
Presiding Member

Bob Betts 8
Member

Paul Sommerville 9
Member

DECISION AND ORDER 10

January 16, 2004 11

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The Applications 15

Union Gas Limited ("Union") filed an application for rates dated May 27, 2002 with the Ontario Energy Board, under section 36 of the *Ontario Energy Board Act, 1998 S.O. 1998*, c.15, Schedule B (the "Act"). Union filed evidence in support of its application on June 25, 2002. The Board assigned file number RP-2002-0130 to Union's application. By letter dated August 1, 2002, Union added to its application a request for changes to the Board's formula used to establish Union's return on common equity ("ROE"). 16

Enbridge Gas Distribution Inc. ("Enbridge" or "EGDI ") filed an application for rates dated September 2, 2002, with the Board, under section 36 of the Act. Included in its application was a request for a change to the Board's formula used to determine EGDI's ROE. The Board assigned file number RP-2002-0133 to the EGDI application. 17

The Proceeding 18

The evidence in relation to the ROE issue relied upon by Union and EGDI in their applications is essentially the same, and both Applicants rely upon the same consultant, Ms.K. McShane. With the consent of the Applicants, the Board decided to hear the ROE issue raised in the two applications in a separate stand-alone proceeding. The Board assigned file number RP-2002-0158 (EB-2002-0484) to this separate ROE proceeding. 19

On December 16, 2002, the Board issued Procedural Order No. 1 setting out the schedule for the proceeding. In accordance with that order, Union filed on February 7, 2003 updated evidence prepared by Ms. McShane. 20

Procedural Order No. 2 issued on March 3, 2003 amended the dates for the proceeding as follows: interrogatories on the Applicants' evidence were due on April 11, 2003; interrogatory responses were due on April 29, 2003; supplementary interrogatories on the Applicants' evidence was due on May 8, 2003 and responses to supplementary interrogatories, were due May 15, 2003; an Issues/Technical Conference was to be held on May 21, 2003; an Issues Day proceeding was to be held on May 23, 2003; intervenor evidence was to be filed by June 27, 2003; interrogatories on intervenor evidence were due by July 11, 2003; interrogatory responses were due by July 25, 2003. 21

Procedural Order No. 3 issued on April 30, 2003 cancelled the Issues/Technical Conference and the Issues Day and specified that a Stakeholders Conference take place on May 23, 2003. Procedural Order No. 4 issued on July 3, 2003 set the commencement of the hearing as September 18, 2003. On August 12, 2003 the Board issued Procedural Order No. 5 which revised the hearing date to September 22, 2003. 22

The Hearing 23

The oral proceeding commenced on September 22, 2003, and concluded on September 26, 2003 after 5 hearing days. 24

The Applicants filed their written argument-in-chief after the close of business October 20, 2003, rather than October 17, 2003 as originally scheduled. Consequently, some intervenors requested a corresponding extension to file their reply argument, which the Board granted. Six intervenors filed their arguments by November 5, 2003. The Board also extended the date on which the Applicants' reply argument was due from November 7, 2003 to November 12, 2003. At the request of the Applicants, the Board further extended the filing date from November 12 to November 21, 2003. 25

Parties and their Representatives 26

Below is a list of parties and their representatives who participated actively by leading evidence or cross-examining witnesses in the oral hearing, or by filing argument. 27

28

Union Gas Limited	Michael Penny Marcel Reghelini
Enbridge Gas Distribution Inc.	Helen Newland Marika Hare
Board Counsel	Patrick Moran
Consumers Association of Canada ("CAC")	Robert Warren
London Property Management Association ("LPMA")	Randy Aiken
Industrial Gas Users Association ("IGUA")	Peter Thompson
Vulnerable Energy Consumers Coalition ("VECC")	Michael Janigan
Energy Probe	Brian Dingwall
Pollution Probe	Murray Klippenstein
Ontario Public School Boards' Association ("OPSBA")	Jay Shepherd
Canadian Gas Association ("CGA")	Laurie Smith

Witnesses 29

The Applicants called the following witness: 30

Kathleen McShane	Senior Vice President, Foster and Associates

IGUA/VECC/CAC called the following witness: 31

Lawrence Booth	Professor of Finance, Rotman School of Management, University of Toronto

32

33 CGA called the following witnesses:

Peter Case	Peter Case Consulting
Michael Cleland	President and Chief Executive Officer, Canadian Gas Association

34 The Board called the following witness:

William Cannon	Associate Professor of Finance, School of Business, Queen's University

35 Submissions and Exhibits

36 Copies of the evidence, exhibits, arguments, and a transcript of the proceeding are available for review at the Board's offices.

37 The Board has considered the evidence, submissions and arguments in the proceeding, but has summarized the evidence and the positions of the parties only to the extent necessary to provide context for its findings.

38 The Board, with industry participation, has developed standards and processes for the electronic regulatory filing ("ERF") of evidence, submissions of parties, Board orders and decisions. This Decision and Order will be available in ERF form shortly after initial copies are issued in hard copy. The ERF version will have the same text and numbered headings as the initial hard copy, but may be formatted differently.

2 SUMMARY OF CURRENT GUIDELINES 39

The Ontario Energy Board currently uses a formula based approach to set the return on common equity ("ROE") for most gas utilities under its jurisdiction. The Board's approach is set out in its *Draft Guidelines on a Formula-Based Return on Common Equity* ("ROE Guidelines"). The ROE Guidelines were first applied in the EBRO 495 proceeding which set fiscal 1998 rates for The Consumers' Gas Company Ltd. (now EGDI). 40

The ROE Guidelines start with the establishment of a benchmark ROE to provide, as it was described in the EBRO 495 decision, "a just and reasonable return on equity" for each gas distribution company. This benchmark ROE is then adjusted for each subsequent fiscal year in accordance with an adjustment mechanism. 41

The benchmark ROE for a utility is set by taking the forecast yield for long-term Government of Canada bonds and adding an appropriate risk premium to account for the utility's risk relative to the long-term Government of Canada bonds. The equity risk premium test is used to determine the appropriate risk premium. 42

The Compendium to the ROE Guidelines, at p.5, described this method as follows: 43

> The equity risk premium test is also designed to measure the cost of equity capital from the capital attraction perspective. It relies on the assumption that common equity is riskier than debt and that investors will demand a higher return on shares, relative to the return required on bonds, to compensate for that risk. The premium required by an investor to assume the additional risk associated with an equity investment is taken to be the difference between the relevant debt rate, usually the yield on long-term government bonds, and some estimate of the stock's cost of equity. The recommended cost of equity value under the equity risk premium approach is therefore usually computed as the sum of the test-period forecast for the government yield and the utility-specific risk premium the analyst has estimated based on historical equity risk premium evidence and forward-looking considerations. 44

The benchmark ROE becomes the allowed ROE for the first year. EGDI's benchmark ROE was set at 10.65% in the EBRO 495 proceeding, based on a risk premium of 340 basis points. Union's benchmark ROE was set at 11.00 % in the EBRO 493-04/494-06 proceeding, based on a risk premium of 355 basis points. The 15 basis points difference reflects the relative risk of the two utilities. The difference of the returns over 15 basis points is accounted for by the difference in the timing of setting the rate or return for the two utilities. 45

Once the benchmark ROE has been established, the allowed ROE is automatically adjusted annually, using a formula. The change in the forecast yield for long-term Government of Canada bonds is multiplied by a factor of 0.75 to determine the adjustment to the allowed ROE. This adjustment 46 factor is then added to the utility's previous test year ROE and the sum is rounded to two decimal points to produce the new ROE.

47 Example:

Allowed ROE for test year 1		10.00%
Test year 2 long-term Government of Canada bond yield forecast	5.00%	
Test year 1 long-term Government of Canada bond yield forecast	5.25%	
change in interest rates	-0.25%	
adjustment factor of 0.75 applied		0.1875%
ROE for test year 2		9.8125%
Approved ROE for test year 2 (rounded to 2 decimal places)		9.81%

48 Regarding the need for review in the future, the ROE Guidelines, in the Compendium at p. 28, state:

49

> The Board believes that the rate of return formula should be reviewed as conditions arise that may call into question its validity (e.g., a change in the relative taxation of the income from debt and equity investments, or a fundamental change in business or financial market conditions). To set a particular time period may be artificial and necessitate an unnecessary review or stifle a review at another time when an adjustment would be appropriate. Parties to a proceeding may ask the Board to review the formula when they feel it is appropriate or the Board may do so on its own initiative. In either case it will be the Board's decision as to the time for a review.
>
> From time to time the Board may request the presentation of other tests or require some weighting for other tests in the formula should the Board want to assure itself that the equity risk premium formula approach does not lead to perverse results and is directionally in line with other market indicators.

3 EVIDENCE AND POSITIONS OF THE PARTIES 50

The Applicants 51

The Applicants relied on Ms. McShane's evidence, in support of their request for a new benchmark ROE and a change to the annual adjustment formula. 52

Ms. McShane concluded that the ROE Guidelines produce an ROE for EGDI and Union that is unreasonably low. This conclusion was based upon her proposed methodology, her analysis of changes in the Canadian bond market since March 1997, and her consideration of the allowed returns for U.S. gas and electric utilities. 53

To formulate her recommendation for a new benchmark ROE in the range of 11.5 - 11.75%, based on a forecast 6.0% yield for long-term Government of Canada bonds, Ms. McShane applied three equity return tests; the Equity Risk Premium (ERP) test, the Discounted Cash Flow (DCF) test and the Comparable Earnings (CE) test. 54

Ms. McShane used three versions of the ERP test which produced an ROE range of 10.5% to 11.25%. 55

Ms. McShane's DCF test, which she applied exclusively to a sample of U.S. utilities, produced an ROE of 11.5%. 56

Ms. McShane applied her CE test to both Canadian and U.S. industrial returns covering the 1992-2001 period, and giving primary weight to the Canadian evidence, this produced an ROE range of 12.75 - 13.25%. 57

Ms McShane then combined these results, weighting the ERP and DCF test results 37.5% each, and the CE test results 25%, to produce her recommendation that an appropriate benchmark ROE would be in the range of 11.5 - 11.75% for an average risk utility. She recommended the mid-point of 11.625% as an appropriate benchmark ROE for Union, as an average risk utility, and 11.5% for EGDI, as a slightly lower risk utility. 58

Ms. McShane noted that the regulated ROE for U.S. gas and electric utilities were typically higher than for utilities in Canada. She was of the view that this divergence could disadvantage Canadian utilities and their shareholders within the context of an increasingly integrated North American capital market environment. 59

Ms. McShane also pointed to a number of changes that had occurred in the bond and equity markets after the ROE Guidelines were established, which she relied on to support her contention that the risk premiums used to set the original benchmark ROE for the Applicants are too low in today's context. 60

CGA 61

The CGA sponsored the evidence of Mr. Cleland and Mr. Case. Mr. Cleland was presented as a policy spokesperson for the CGA and his evidence was limited to confirming that the CGA supported a higher ROE for Canadian utilities, including the Applicants. 62

Although Mr. Case did not propose any changes to the current ROE formula or the annual adjustment mechanism, his view was that an ROE in the range of 10.5 - 11.0% would be viewed by equity markets as a fair return, based on his telephone discussions with various equity market participants and analysts. 63

His recommendation was based on the following five factors. 64

First, Mr. Case claimed that the formula no longer compensates investors appropriately for an increase in the perceived riskiness of utilities since 1997. 65

Second, according to Mr. Case, recent market conditions limit the usefulness of the Capital Asset Pricing Model (CAPM) because market conditions have artificially depressed utility stock betas. 66

Third, he suggested that the continuing globalization of capital markets since the Board issued its 1997 ROE Guidelines has made a comparison to higher US utility returns more relevant. The lower returns of Canadian utilities put them at a competitive disadvantage in attracting capital. Mr. Case pointed to the recent sale by Aquila Inc. of its Canadian utility as an example of an investor not willing to invest in a utility in British Columbia or Alberta because the ROE was too low. He also pointed to some examples of Canadian utility holding companies that experienced difficulty in raising common equity as a further demonstration that the current level of ROE for Canadian utilities was a problem. 67

Fourth, with the significant decline in bond yields since 1997, the formula has resulted in a decline in equity returns that is faster than the decline in the utilities' embedded cost of debt. As a result, there has been downward pressure on utility interest coverage ratios, which in turn puts pressure on utility debt ratings. 68

Finally, Mr. Case believed that the majority of institutional equity investors view the returns currently generated by the formula based approach used by the Board and other Canadian regulators as inadequate. 69

CAC, IGUA and VECC 70

CAC, IGUA and VECC sponsored the prefiled report prepared by Drs. Booth and Berkowitz. The authors concluded that a fair ROE for the Applicants is in the range of 8.5%, which includes a 50 71 basis point "cushion" above their estimates of the cost of attracting capital for these utilities. Only Dr. Booth testified in the hearing but he adopted the joint prefiled evidence.

In their report, Drs. Booth and Berkowitz came to their ROE recommendation by applying two versions of the ERP test and giving equal weight to the results. Their first ERP test was the single-factor Capital Asset Pricing Model (CAPM), while their second ERP test relied on a two-factor model which differentiated between the systematic risk due to changes in the equity market and changes in security returns due to fluctuations in interest rates. 72

Their application of the CAPM model yielded an ROE in the range of 8.02% to 8.47%. This was based on their assessment that (1) the market risk premium is now 4.5% and (2) a reasonable range for the beta risk of an average-risk regulated Canadian utility is 0.45 to 0.55. 73

Applying their two-factor model, which incorporates a term premium estimate of 1.00%, produced an ROE in the range of 7.66% to 7.74%. 74

In further support of their proposed benchmark ROE of 8.5%, Drs. Booth and Berkowitz produced DCF test results, based on a sample of U.S. utilities, that pointed to an ROE in the range of 7.89 to 8.57%. 75

In testimony, Dr. Booth indicated that he did not see a need to move away from the Board's ROE Guidelines, even though their analysis suggested that the ROE Guidelines produced an ROE that was more generous than it needed to be. In their report, Drs. Booth and Berkowitz stated their belief that the 75% adjustment factor was a reasonable compromise between (a) assuming that the overall required return on the stock market is independent of long-term Government of Canada bond yields implied by a 50% adjustment coefficient, and (b) assuming that the riskiness of the long-term Government of Canada bond relative to the equity market is constant, as implied by a 100% adjustment factor. 76

Finally, Drs. Booth and Berkowitz pointed out that the market-to-book-value ratios of all Canadian utilities, save one, were well in excess of 1.0. They stated that this was a clear indication that utilities have not suffered a loss of financing flexibility since Canadian regulators moved to automatic ROE adjustment mechanisms based on long-term Government of Canada bond yields, beginning in 1994. 77

Dr. Cannon 78

Dr. Cannon was retained by the Board to provide additional evidence on the ROE issues. He prepared a report that was provided to all parties and he answered interrogatories on his evidence. He also appeared as a witness and was cross-examined by the parties. His expert opinion, as with the other expert witnesses, was provided to the Board entirely on the public record. 79

In his evidence Dr. Cannon concluded that there had been a substantial decline in the equity capital costs for the average-risk Canadian gas utility and for Ontario's major gas distributors since 1996. 80

According to Dr. Cannon, there is no evidence to suggest that the application of the Board's ROE formula methodology had resulted in allowed returns which had violated either the fair return or financial integrity standards of regulatory rate setting. 81

He also submitted that the decrease in ROE under the ROE Guidelines had been less than it would have been, applying the capital attraction standard of regulatory rate setting instead. 82

It was Dr. Cannon's view that an appropriate benchmark ROE for the average-risk Canadian energy utility now lies in the range of 7.5% to 7.9%, lower than the ROE that would currently be produced under the ROE Guidelines. Dr. Cannon's benchmark ROE recommendation is based primarily on results from using the three equity return tests that Ms. McShane used. In using those tests, he applied different judgment and reached different conclusions than Ms. McShane did. 83

Using his ERP test, Dr. Cannon concluded that an appropriate ROE would be in the range of 6.35-6.55% for the average-risk Canadian energy utility, based on a mid-June estimate of 4.00% for the yield on a truly riskless long-term Canadian asset and a corresponding "all-in ERP" in the 2.35-2.55% range. His utility ERP test findings reflected the substantial decline in the prospective market risk premium in recent years as well as the continuing low relative investment riskiness of the typical energy utility. 84

Applying the DCF test to a sample of Canadian energy utilities produced a benchmark ROE in the range of 7.9% to 8.5%. 85

The CE test, using data for Canadian industrials over the 1991-2002 period produced an ROE of 10.2% for Dr. Cannon. 86

To arrive at his final recommendation for a benchmark ROE, Dr. Cannon applied different weights to his three test results than Ms. McShane. Dr. Cannon weighted his results from the three tests as follows: ERP - 60%, DCF - 15%, and CE - 25%. 87

Dr. Cannon's ROE recommendation reflected an "all-in benchmark ERP" of 2.93% above the long-term Government of Canada bond yields prevailing in mid-June. 88

With respect to the adjustment formula, Dr. Cannon proposed that the adjustment factor applied to changes in the forecast long-term Government of Canada bond yields be reduced to 70%, from the current 75% value. He based this on his view of the sensitivity of his equity return tests to changes in the long-term Government of Canada bond yields and his weighting of the three tests. 89

Dr. Cannon concluded that, all other things being equal, the ROE numbers produced by the ROE Guidelines in recent years are likely too high. 90

LPMA 91

LPMA did not rely on the evidence of any particular expert as, in its opinion, the analysis of any one expert did not produce a definitive estimate of a fair return. Instead, LPMA gave equal weight to the results of the work done by Ms. McShane, Dr. Cannon and Drs. Booth and Berkowitz, with one exception. LPMA argued that zero weight should be given to Ms. McShane's CE test because, in the view of LPMA, the market risk premium was overstated. 92

LPMA's final recommendation for a new benchmark ROE was 8.96% based on giving equal weight to the three expert's evidence, removing the CE test, applying a market risk premium of 325 basis points, and averaging the three ERP estimates produced by Ms. McShane, Dr. Cannon and Drs. Booth and Berkowitz. 93

LPMA submitted that the CE test should not be relied on because of the difficulty in assembling an acceptable sample of comparable companies against which to assess the regulated utility. First, LPMA noted that both Dr. Cannon and Ms. McShane selected comparable industrials yet the results were 300 basis points apart. Second, there had been debate regarding the appropriate earnings to use and widespread concern regarding corporate reporting which placed the accuracy of the information in doubt. Third, the American returns were not suitable comparators as the American economy was generally more competitive resulting in higher risks and consequently higher returns. Fourth, LPMA noted that Canadian regulators often gave little or no weight to the CE test. 94

School Boards 95

School Boards also did not call any evidence. School Boards recommended that the Board approve an ROE of 9.0% for EGDI, assuming a risk-free rate of 5.4%. 96

With respect to Union Gas, School Boards believed that there was no evidence to suggest that Union Gas was any riskier that EGDI. The premium paid by Duke when it acquired Union suggested that Union was not as risky as Ms. McShane or Dr. Cannon believed. Further, the fact that the two utilities are at the same deemed equity ratio implied that they could be considered to be at the same risk level. Therefore, School Boards submitted that the Board should approve an ROE of 9.0% for Union Gas as well. 97

School Boards noted that the debate of the experts demonstrated that the same underpinning numbers could produce different results. Therefore the expert evidence was suspect, as all of the experts chose and manipulated data in ways that limited the objectivity of their conclusions. The School Boards argued that, given this uncertainty among experts regarding the appropriate ROE tests, greater weight should be placed on evidence other than that of the experts. 98

School Boards' position was therefore not tied to that of the experts. Instead it proposed a different approach. School Boards proposed five tests to arrive at its 9.0% ROE recommendation. 99

The first test, named the "mind experiment", consisted of arriving at a number representing the intersection of the experts' broadest ranges of ROE. 100

The second test, using the Seigel Tables, implied a long term market return for utilities of 7.56% to 7.74% if compound returns were used. If arithmetic mean returns were used, then the resulting ROE would be in the range of 8.46% to 8.72%. 101

The third test, based on expectations of pension funds, suggested that utility ROE should be no more than 8.5%. 102

The fourth test, the premium paid by Duke, Union's parent company, demonstrated that the current ROE resulting from the formula was somewhat high. According to School Boards, assuming that the current ROE was too high by 50 basis points, the resulting ROE would be 8.76 for EGD and 8.91% for Union Gas. 103

The fifth test, a simple average of the experts' recommendations, resulted in an ROE of 9.05%. 104

Combining these five approaches led School Boards to recommend a new benchmark ROE of 9.0% for both Applicants. 105

With respect to the adjustment mechanism, the School Boards supported the proposal of the Applicants to adjust the ROE annually by 50% of the change in the forecast long-term Government of Canada bond yields. 106

Energy Probe 107

Energy Probe also did not rely on the evidence of any particular expert. It submitted that there was no need to make any changes to the ROE Guidelines and that the ROE Guidelines should be re-affirmed to signal stability and predictability in Ontario's natural gas environment. 108

Energy Probe submitted that there was no evidence that the Applicants had suffered any capital shortage under the current ROE Guidelines. In fact, the formula seemed to provide adequate consideration of costs related to maintaining access to capital markets. Furthermore, it was not necessary to make changes to the ROE formula to address changes to business and financial risk because other mechanisms, such as deferral accounts, were available to the Board for this purpose. 109

Energy Probe suggested that the actual financial performance of utilities demonstrated that they were low risk enterprises and that the argument for any alteration to the ROE formula was weak. Energy Probe noted that over the last decade, both utilities had consistently outperformed the Board allowed ROE. 110

Pollution Probe 111

Pollution Probe did not address the issue of the appropriate ROE formula. Rather it requested that the Board permit the Applicants to earn an additional ROE, over and above what the ROE Guidelines would produce, as an incentive to aggressively promote cost effective energy conservation and efficiency. 112

113

4 BOARD FINDINGS

The Board's ROE Guidelines suggest that there are two reasons which would justify a review of the formula. The first justification would be significant changes in market conditions. The second justification would be significant changes in the utility risk. The Applicants have based their request for a review on their assertion that there have been significant changes in the capital markets. There is no claim that the utility risk per se has increased. The Board recognizes that the ROE Guidelines are not binding and that it is always open to a party to propose a new approach. The Applicants have made such a proposal and the Board has considered on its merits. 114

The first issue for the Board is whether the adjustment mechanism contained in the current ROE Guidelines produces a prospective return on common equity that continues to be appropriate. The formula in the current guidelines produces an ROE of 9.71% for Enbridge and 9.86% for Union at a long-term Government of Canada bond yield of 6.00%. This reflects a risk premium of 371 basis points for Enbridge and 386 basis points for Union. At a long-term Government of Canada bond yield of 6.00%, the Applicants are asking the Board to set a new benchmark ROE of 11.50% for Enbridge and 11.65% for Union. This proposal reflects an increase in the risk premium to 550 basis points for Enbridge and 565 basis points for Union. They are asking the Board to move from sole reliance on the equity risk premium (ERP) test, as set out in the ROE Guidelines, to weighted reliance on three tests described in Ms. McShane's evidence: the ERP test (37.5%), the discounted cash flow (DCF) test (37.5%) and the comparable earnings (CE) test (25%). 115

The second issue for the Board is the Applicants request, based on Ms. McShane's evidence, for a change to the annual adjustment formula, so that in each succeeding year, the ROE is adjusted by 50% of the change in the forecast yield for long-term Government of Canada bonds, rather than the 75% required by the ROE Guidelines. However, this request was contingent upon the outcome of the first issue. 116

The third issue for the Board is the request by the Applicants, based on Ms. McShane's evidence, that the factor representing the yield spread between the 10 and 30 year Government of Canada bonds be fixed, rather than being calculated annually. Dr. Cannon makes the same suggestion, although he recommends a lower spread than Ms. McShane. 117

First, we will deal with the primary issue of whether a new benchmark ROE should be established for EGDI and Union. 118

In approving or fixing rates, the Board derives its jurisdiction from section 36 of the Act. Pursuant to that section, the Applicants can only charge rates for the distribution of gas with the approval of the Board. The burden of proof to demonstrate that the rates applied for are just and reasonable lies with the Applicants. The setting of just and reasonable rates involves the balancing of the interests of the Applicants, on the one hand, and the ratepayers, on the other hand. Rates will be just and reasonable when the ratepayers are paying a fair price for the distribution services that they receive and the Applicants have an opportunity to earn a fair return on their invested capital. Allowance for 119 a prospective fair return on common equity is therefore a component of establishing just and reasonable rates.

120 Section 36 (3) of the Act provides that the Board can adopt any method or technique for the setting of rates that it deems appropriate. The method to be adopted is at the Board's discretion, which the Applicants, the expert witnesses and other parties acknowledge. Currently, for the purpose of establishing the ROE for a utility, the Board uses a formula based approach, as set out in the ROE Guidelines, based on the ERP test. The institution of this formula and its application dates back to 1997. None of the parties have proposed that the Board should move away from a formula based approach. We are of the view that it is appropriate to continue with a formula based approach because it provides a significant degree of predictability and is compatible with both cost of service and performance-based regulation.

121 A great deal was made in the hearing by Ms. McShane and the Applicants about comparisons with American utilities and returns awarded by other Canadian jurisdictions. The Applicants argue that the returns of American utilities are higher and that this supports the need for higher returns for the Applicants. They also cite decisions by certain Canadian regulators in support of higher returns. Yet, they also argue that the Board should not be influenced by the unfavourable decisions for recalibrating the existing formula by certain other Canadian regulators, on the basis that this Board should lead rather than follow. Also, they state that the Board must consider the applications on their own merits.

122 Discussions of ROE decisions from other jurisdictions invariably come into the evidence and arguments of parties. We continue to view such evidence as informative. However, we do not believe that decisions in other jurisdictions are determinative of what ought to be a prospective fair ROE for Ontario utilities. There are many reasons why ROE may differ from one jurisdiction to another in North America. These may include differences in legislation, timing, tax laws, accounting practices, risk considerations arising from different capital structures and from regulatory practices which may or may not shield the utility from business or weather risks, and other regulatory considerations unique to each jurisdiction, including varying reliance on the common tests for determining a fair ROE. There was no evidence that would allow the Board to make a meaningful comparison of these factors, including the relative riskiness of Canadian and American utilities, in order to understand the difference in ROE between American and Canadian utilities. The bare fact that American utilities might earn a higher ROE than Canadian utilities, as suggested by Ms. McShane and argued by the Applicants, is an inadequate basis upon which to determine whether the ROE for the Applicants should be increased to a level similar to the ROE for American utilities. Similarly, the fact that some Canadian regulators may have awarded higher or lower returns than the Ontario Energy Board, while informative, is not determinative for largely the same reasons.

123 Ms. McShane suggested that the difference in ROE between American and Canadian utilities was a factor that could create a disadvantage for Canadian utilities and their shareholders. However, we find no evidence to suggest that such a disadvantage currently exists or is likely. Mr. Case suggests that Union, for example, must now compete for equity capital with the other global subsidiaries of Duke Energy, Union's parent; if Union cannot offer a competitive return with the other units, capital might be more difficult to obtain from the parent company. There was no evidence before the Board to suggest that the Applicants are experiencing any difficulty in raising equity capital from or through their respective parents.

124 A long standing regulatory principle espoused by the Ontario Energy Board, and by other regulators in North America, is the stand-alone principle. Applying this principle, the issue is what ought to be a prospective fair return on investment for a utility on a stand-alone basis, and not how a prospective return may compare or compete with other business units of the parent company. Should it be the case that the Ontario gas utilities are unable to attract equity capital by virtue of competition at the parent company level, whether the parent company is foreign or domestic, this would be of great concern to the Board.

125 There was no evidence before the Board to suggest that Canadian utilities in general were experiencing difficulty in raising capital, or doing so at unreasonable terms. Mr. Case mentioned that BC Gas had difficulty raising equity; the equity issue "sat on the shelf" until the dealers were willing to discount it. Dr. Booth countered this point by explaining that the reason that the equity issue sat on the shelf was due to the fact that there was a bidding war amongst investment dealers due to a shortage of such deals at that time. The winning dealer paid a premium for the equity issue in order to secure the underwriting fees. Dr. Booth suggested that this example was in fact a demonstration of how easily a utility could raise capital.

126 Mr. Case pointed to the recent sale of a Canadian pipeline utility by Aquila Inc. as an example of an investor unwilling to invest in Canada. However, the evidence revealed that Aquila was able to sell its pipeline utility to Fortis Inc. at a considerable premium, which would suggest that there are investors willing to invest in Canadian utilities. There was no evidence that Aquila Inc. sold its utility because of concern of the ROE earned by that utility. In fact, the evidence reveals that utility ownership transfers in recent history have taken place at above book value. While there may be many reasons that a company may be willing to pay more than book value for utility assets, there was no evidence to suggest that investors are deterred from investing in Canadian utilities because of inadequate prospective returns.

127 We found no evidence of the Applicants being in financial hardship as a result of the authorized ROE. The Applicants confirmed that they continue to be responsible for raising their own debt capital. There was no evidence, for example, that the allowed ROE has resulted in inadequate financial ratios to preclude raising debt capital on reasonable terms. Similarly, there was no evidence before the Board to suggest that credit ratings of the Applicants were deteriorating. The evidence is that the Applicants enjoy favourable credit ratings. In fact, Union's credit rating is more favourable than its parent company.

128 Mr. Case made references to changes in the business risk faced by the Applicants, but that issue was not before the Board. The Applicants made their request for a change in ROE based on the capital markets and not on any financial or business risk that they were facing. Ms. McShane confirmed in responding to questions that business and other risks covered by the equity component of capital structure were not matters at issue in this hearing. The Applicants did not dispute this testimony.

129 Having found no evidence of returns being inadequate so as to jeopardize the financial and operational aspects of Enbridge and Union, the issue then is whether the rate of return resulting from the equity risk premium test under the current ROE Guidelines is appropriate.

130 Three tests, and their variants, were employed or critiqued by the experts. All three witnesses had varying views with respect to the appropriateness of relying on the ERP test, the DCF test and the CE test. This was a large contributor to the differences between their recommendations. The other large contributor to the difference was the results arrived at by employing the same tests. The evidence of Ms. McShane, Dr. Booth and Dr. Cannon makes it clear that a great deal of judgment is involved in determining what is an appropriate ROE for a utility. Those three witnesses, along with Mr. Case, were looking at the same capital markets but came up with significantly different recommendations to the Board. However, Dr. Booth and Dr. Cannon also conceded that the current ROE Guidelines were still generally appropriate, despite their recommendations for a lower benchmark ROE. Ms. McShane was more categorical in her view that the ROE Guidelines were no longer producing a fair ROE and that a new benchmark ROE and adjustment formula were needed.

131 On the basis of the evidence adduced in this proceeding, we find that the reservations the Board expressed in the compendium to the current ROE Guidelines about the CE and DCF approaches and the Board's decision not to employ these tests remain valid. With respect to the CE test, we continue to be concerned with the problems associated with the assembling of an acceptable list of comparable companies against which to assess the regulated utility, as well as the selection of a suitable time period from which to draw historical evidence. We note that the subjectivity involved in the selection of an appropriate sample of comparators and the selection of the time period were the primary factors in arriving at an ROE difference of 300 basis points between Ms. McShane and Dr. Cannon. We also reiterate our concern with this test's heavy reliance on past performance as an indicator of future performance.

132 With respect to the DCF test, we note the sensitivity of the results to assumptions, including growth estimates. We note that as a result of different assumptions, Ms. McShane's ROE result from the DCF test is over 200 basis points higher than the results obtained by Dr. Booth and Dr. Cannon. Further, in the context of the specific applications before us, we remain uncomfortable with the results of the DCF test given that the shares of the Applicants are no longer traded on the open market.

133 As a result of the above, we reiterate the Board's conclusions reached when it developed the existing ROE Guidelines that the results from the CE and DCF tests should be given little or no weight for purposes of these applications.

134 We do not accept the suggestions by certain parties to use the approach of averaging the recommendations or to embark on tests that do not have theoretical foundation. Therefore for the purposes of this proceeding we will rely primarily on the results of the ERP test. Other than Mr. Case, all expert witnesses used this test.

135 There are four basic components to this test: a determination of the risk-free rate; a determination of the equity risk premium for the market as a whole; an adjustment (beta) to reflect the lower risk of utilities; and an allowance for financial flexibility or "cushion". Supplemental analysis to the basic ERP test was performed by Ms. McShane and Drs. Booth and Berkowitz.

136 No party has disputed the use of the long-term Government of Canada bond yield as the basis of the risk free rate, or the basis for its forecast as contained in the current ROE guidelines other than the

suggestion to fix the spread between the 10 and 30 year bond yields. Also, there was no dispute about the 50 basis points cushion. The disputes are around the determination of the market risk premium and the risk adjustment to reflect the lower risk for utilities.

137 Ms. McShane calculates a market risk premium of between 600 and 650 basis points. Dr. Booth calculates the premium at about 450 basis points and Dr. Cannon at about 350 basis points. The recommendations of a benchmark return under the basic ERP test of about 400 basis points for Ms. McShane, about 200 basis points for Dr. Booth, and about 160 basis points for Dr. Cannon reflect their choice of a relative risk adjustment of 0.60-0.65, 0.45-0.55, and 0.45, respectively. Adding the 50 basis points of cushion, the recommended benchmark equity risk premium under the basic test for Ms. McShane is 450 basis points, for Dr. Booth 250 basis, and for Dr. Cannon 210 basis points.

138 On the basis of the record adduced in this proceeding, we are of the view that Dr. Cannon's result is too low and Ms. McShane's too high. We find that the record reasonably supports a risk premium for the market as a whole between 500 and 550 basis points. We note from the evidence that the Alberta Energy and Utilities Board which recently reviewed similar data concluded that the market premium is 525 basis points. This is the mid-point of our 500 to 550 range. Using this mid-point figure, and without any modifications to Ms. McShane's recommended risk adjustment, one would obtain an overall equity risk premium of about 375 basis points, inclusive of the 50 basis points cushion. These equity risk premiums compare with 371 basis points for Enbridge and 386 basis points for Union under the current ROE Guidelines. Ms. McShane's recommended risk adjustment is higher than the other experts. A lower risk adjustment than that recommended by Ms. McShane would result in the equity risk premium under the current formula being favourable to the Applicants.

139 Ms. McShane used two other tests under the risk premium method, both utilizing utility data only. The first was the DCF based equity risk premium test, which produced an equity risk premium of 460 to 470 basis points. For the reasons outlined in the discussion of the DCF approach above, and our observation that the results indicate a much higher equity risk premium than the basic test produces, we place little or no weight on these results.

140 The second is a historic test, using data from both Canadian and American utilities. This test produced an equity risk premium of 475 to 500 basis points. We similarly place little or no weight on these results. We are not comfortable with the circularity that is inherent using regulated utility data, and the inclusion of American utilities which may bias the results without a thorough understanding of the justification for the higher returns of these utilities.

141 We conclude that not only does the equity risk premium formula approach not lead to perverse results, but that the results it currently provides continue to represent fair and reasonable returns. If we had to set a new benchmark rate of return based on the ERP evidence in this proceeding, this rate would not be materially different from that produced by applying the current formula.

142 Therefore, with respect to the first and primary issue of whether a new benchmark ROE should be established for EGDI and Union, we find that the current ROE Guidelines methodology continues to produce appropriate prospective results. We have not found any demonstrated need to set a new benchmark ROE.

Given this finding, the second issue, the Applicants' request for the annual ROE adjustment to be decreased to 0.50 from 0.75 of the change in the forecast yield for long-term Government of Canada bonds, is moot. 143

As for the third issue, the suggestion that the factor representing the yield spread between the 10 and 30 Government of Canada bonds be fixed rather than being calculated annually, the Board does not consider this to be of sufficient consequence, by itself, to justify a change to the existing guidelines. 144

Accordingly, based on the foregoing findings, the Board orders that the applications are dismissed. 145

In making this determination, the Board also considered the proposal put forward by Pollution Probe to increase ROE as an incentive to promote cost effective energy conservation and efficiency. The Board notes that the Applicants currently have demand side management programs in place that have already been ruled upon. This proceeding is focussed on whether conditions in the capital markets warrant a change to the Board's formula based approach to setting the ROE for the Applicants. The Board also notes that Pollution Probe and the Applicants are participating in a broad Board initiative that is examining energy conservation and efficiency. 146

The Board will issue a separate decision on cost awards. 147

DATED at Toronto January 16, 2004 148

On behalf of the Hearing Panel

Paul Vlahos
Presiding Member

K7.2

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Vancouver • Toronto • Ottawa • Montréal • Calgary

By E-mail

February 2, 2007

Ontario Energy Board
FILE No. EB-2006-0034
EXHIBIT No. K7.2
DATE February 6, 2007
08/99

Fred Cass
Aird & Berlis LLP
BCE Place, Suite 1800
Box 754, 181 Bay Street
Toronto, ON M5J 2T9

Dear Mr. Cass

Enbridge Gas Distribution Inc. 2007 Rate Case
OEB File No.: EB-2006-00034
Our File No.: 302701-000398

The purpose of this letter is to provide EGD's Cost of Capital Witness Panel with advance notice of our intent to ask questions about the impact of EGD's overall depreciation rate of about 4.56% (see Exhibit D, Tab 13, Schedule 1, page 3, line 7, column 4) on EGD's interest coverages compared to the overall depreciation rates for other utilities such as Union Gas Limited ("Union") of about 3.3% and TransCanada PipeLines Limited ("TCPL") of about 3.42%.

We are enclosing with this letter a copy of excerpts from the National Energy Board's ("NEB") Reasons for Decision in RH-1-2002 dated July 2003 wherein the NEB established TCPL's composite depreciation rate at about 3.42%. We are also enclosing copies of Exhibit D3, Tab 4, Schedule 1 in Union's 2007 Rate Case which shows its provision for depreciation which we calculate to be about 3.3%.

EGD's composite depreciation rate of 4.56% exceeds that of Union and TCPL by at least 1.14%. We estimate that the component of EGD's 2007 revenue requirement attributable to depreciation is about $60.4M higher than it would be if EGD's depreciation rate were comparable to that of Union and TCPL (EGD's depreciable plant of $5,294.9M shown at Exhibit D1, Tab 13, Schedule 1, page 3, line 6, column 2 multiplied by 1.14% = $60.36M).

Compared to Union and TCPL, EGD's favourable depreciation rate provides it with enhanced interest coverage calculated on an Earnings Before Depreciation and Income Taxes basis.

We will also be noting the incompatibility between EGD's composite depreciation rate of 4.56% and the revenue horizon assumption for residential main expansion of forty (40)

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years from the in-service date which EGD applies to determine the economic feasibility of system expansion, as described in Exhibit B2, Tab 1, Schedule 1, page 4 of 9.

Would you please bring the contents of this letter to the attention of your Cost of Capital Witness Panel so that they will be prepared to respond to this line of inquiry when we cross-examine them next week.

Yours very truly

Peter C.P. Thompson, Q.C.

PCT\slc
enclosures
c. Board Secretary
Intervenors EB-2006-0034

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5

National Energy Board
Office national de l'énergie

Reasons for Decision

TransCanada PipeLines Limited

RH-1-2002

July 2003

Tolls and Tariff

disagreement between TransCanada and GFI on net salvage on terminal retirements remains unresolved. In Ontario's view, there would be greater cost certainty if all elements of depreciation, including net salvage on terminal retirements, were dealt with at once in one proceeding. In addition, approving TransCanada's claim for depreciation will further reduce the cost competitiveness of the Mainline. For these reasons, Ontario submitted that TransCanada's claim related to depreciation should be denied.

Views of the Board

Other Matters

The Board notes the importance of performing depreciation studies on a timely basis and of ensuring that depreciation rates reflect up-to-date information. The Board notes TransCanada's expert witness recommended that depreciation studies be performed every three to five years and that TransCanada accepted this recommendation. Accordingly, the Board would expect the filing of TransCanada's next comprehensive depreciation study to be within this time frame.

The Board does not agree with Ontario's suggestion that the Board delay a decision on depreciation matters until all elements of depreciation, including net salvage on terminal retirements, could be dealt with in one proceeding. In the Board's view, denying all of TransCanada's depreciation proposals at this time would result in an improper recovery of depreciation expenses in 2003 and future shippers having to pay disproportionately large depreciation charges.

Overall Views on Depreciation

The Board is of the view that it would be appropriate to implement a composite depreciation rate that reflects all aspects of the TransCanada depreciation study, with the exception of the proposed change from ASL to ELG. Further, the Board is of the view that TransCanada should offset any salvage proceeds it may receive from the disposition of assets in accounts subject to amortization accounting against the additions in a particular vintage year and then apply amortization accounting to the net amount. Based on TransCanada's calculations, which are reproduced in Table 5-1, the Board expects that the resulting composite depreciation rate will be approximately 3.42% for 2003. The exact level of the composite depreciation rate will be confirmed once TransCanada files its compliance tolls filing.

UNION GAS LIMITED
Provision for Depreciation,
Amortization and Depletion
Calendar Year Ending December 31, 2007

Line No.	Particulars ($000's)		
1	Total provision for depreciation and amortization before adjustments (per page 3)	$	179,652
2	Adjustments: vehicle depreciation through clearing		1,150
3	Provision for depreciation amortization and depletion	$	178,502

UNION GAS LIMITED
Provision for Depreciation, Amortization and Depletion
Calendar Year Ending December 31, 2007

Line No.	Particulars ($000's)	Average Plant (1) (a)	Rate (%) (b)	Provision (c)
	Intangible plant:			
1	Franchises and consents	$ 2,090		$ 69
2	Intangible plant - Other	9,370		123
3		$ 11,460		$ 192
	Local Storage Plant			
4	Structures and improvements	$ 2,193	3.30%	$ 72
5	Gas holders - storage	6,048	2.68%	162
6	Gas holders - equipment	6,895	3.68%	254
7		$ 15,136		$ 488
	Storage:			
8	Land rights	$ 51,512	2.23%	$ 1,149
9	Structures and improvements	55,744	2.34%	1,304
10	Wells and lines	140,026	2.66%	3,725
11	Compressor equipment	276,181	3.19%	8,810
12	Measuring & regulating equipment	56,053	4.3%	2,410
13	Other equipment	0	0.00%	0
14		$ 579,515		$ 17,398
	Transmission:			
15	Land rights	$ 37,019	2.00%	$ 740
16	Structures and improvements	44,286	2.66%	1,178
17	Mains	962,589	2.37%	22,813
18	Compressor equipment	172,791	3.52%	6,082
19	Measuring & regulating equipment	124,178	3.61%	4,483
20		$ 1,340,863		$ 35,296
	Distribution - Southern Operations:			
21	Land rights	$ 4,500	1.67%	$ 75
22	Structures and improvements	71,534	2.91%	2,082
23	Services - metallic	110,630	3.69%	4,082
24	Services - plastic	675,920	3.18%	21,494
25	Regulators	63,177	3.30%	2,085
26	Regulator and meter installations	52,975	3.51%	1,859
27	Mains - metallic	391,540	2.54%	9,945
28	Mains - plastic	450,811	2.34%	10,549
29	Measuring & regulating equipment	37,141	4.64%	1,723
30	Meters	171,304	3.70%	6,338
31	Other equipment	0	0.00%	0
32		$ 2,029,532		$ 60,232

UNION GAS LIMITED
Provision for Depreciation, Amortization and Depletion
Calendar Year Ending December 31, 2007

Line No.	Particulars ($000's)	Average Plant (1) (a)	Rate (%) (b)	Provision (c)
	Distribution plant - Northern & Eastern Operations:			
1	Land rights	$ 8,821	1.68%	$ 148
2	Structures & improvements	46,134	3.13%	1,444
3	Services - metallic	87,724	3.58%	3,141
4	Services - plastic	317,464	3.19%	10,127
5	Regulators	23,146	3.34%	773
6	Regulator and meter installations	22,102	3.50%	774
7	Mains - metallic	316,087	2.52%	7,965
8	Mains - plastic	176,582	2.35%	4,150
9	Compressor equipment	1,341	3.34%	45
10	Measuring & regulating equipment	77,066	4.63%	3,568
11	Meters	52,881	3.67%	1,941
12	Other distribution equipment	0	0.00%	0
13		$ 1,129,346		$ 34,075
	General:			
14	Structures and improvements	$ 38,193	2.13%	$ 814
15	Office furniture and equipment	15,552	6.67%	1,037
16	Office equipment - computers	84,040	25.00%	21,010
17	Transportation equipment	49,489	10.07%	4,984
18	Transportation equipment - aircraft	0	3.40%	0
19	Heavy work equipment	13,912	4.55%	633
20	Tools and other equipment	31,252	6.67%	2,083
21	Communications equipment	18,688	6.67%	1,246
22	Communications structures	3,361	4.88%	164
23	Other equipment	0	0.00%	0
24		$ 254,486		$ 31,971
27	Contributions in aid of construction	0	2.50%	0
28	Sub-total	$ 5,360,339		$ 179,652
25	Total provision for depreciation and amortization			$ 179,652
26	Depreciation through clearing			1,150
27		$ 5,360,339		$ 178,502

Notes:

(1) A simple average of the opening and closing plant balances was used to calculate the annual depreciation provision.

Castanza, Suzanne

From: Thompson, Peter C. P.
Sent: February 2, 2007 12:43 PM
To: 'Cass, Fred'
Cc: Board Secretary; DeRose, Vincent J.; Abouchar, Juli; Adams, Tom; Aiken, Randy; Alexander, Basil; Battista, Richard; Buonaguro, Michael; Cass, Fred; Chiasson, Lorraine; Clark, Janet; Crain, Kirsten; Cramer, Duane; DeMarco, Elisabeth; DeRose, Vincent J.; DeVellis, John; Duffy, Patrick; Duzy, Margaret; Findlay, Rob; Fournier, Peter; Gibbons, Jack; Gibbs, Andrea; Girvan, Julie; Harbell, James; Higgin, Roger; Hoaken, Eric; Hoey, Patrick; Jackson, Malcolm; Kerr, Paul; Klewchuk, Patricia; Klippenstein, Murray; Ladha, Shiraz; Landymore, Heather; Luymes, Martin; MacDonald, Glen; MacIntosh, David; Manning, Paul; Matthews, Dave; Matz, Thomas; Mauviel, Lise; McCamus, Greg; McMahon, Pat; Millar, Michael; Millyard, Kai; Newton, Murray; Nolan, Catherine David; O'Connor, Sandy; Pelletier, Bernard; Persad, Tania; Poch, David; Reuber, Barbara; Ross, Murray; Ruzycki, Nola; Scott, Jennifer; Serafini, Pete; Shepherd, Jay; Spratt, Shari-Lynn; Stacey, Jason; Thompson, Peter C. P.; Toronto Hydro; transcanada_mainline@transcanada.com; Warren, Robert; Watson, Tanya; Wightman, James; Williams, Bob; Young, Valerie; Clermont, Marc; Killeen, Bill; Makohoniuk, Rodney
Subject: EB-2006-0034 - IGUA Letter
Attachments: LTR Cass Feb 02 2007.pdf; OTT01-3137919-v1-LTR_Cass__Attachments.PDF

Attached please find a letter and enclosure submitted by the Industrial Gas Users Association ("IGUA").

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Ontario Energy Board
Commission de l'Énergie de l'Ontario

Ontario

EB-2005-0001/EB-2005-0437

IN THE MATTER OF AN APPLICATION BY

ENBRIDGE GAS DISTRIBUTION INC.

2006 RATES

DECISION WITH REASONS

February 9, 2006

Ontario Energy Board
FILE No. EB-2006-0034
EXHIBIT No. K7.3
DATE February 6, 2007
page 91 only.
08/99

10.10 SHOULD THE BOARD BE CONCERNED THAT ACTUAL PAYMENTS TO EI WILL BE IN ACCORDANCE WITH CAM – NOT RCAM?

10.10.1 It was clear from the evidence that regardless of the results of the RCAM, the payment for corporate services from Enbridge to EI will continue to be governed by CAM. Schools expressed concern regarding the payment of the CAM amount, and recommended the use of an Excess Earnings Variance Account to capture payments from overearnings.

10.10.2 Enbridge responded that it intended to honour its contracts, that it had a legal contract and that it needed the services governed by the contract. Enbridge submitted that the development of RCAM did not invalidate CAM. It asserted that RCAM was developed in recognition of the need to tailor the methodology to meet the needs of the Board. Enbridge maintained that it was practical to use CAM because of other subsidiaries within the EI Group.

10.11 BOARD FINDINGS

10.11.1 The Board is concerned that CAM will govern actual payments. The Board notes the testimony of both Enbridge and EI witnesses to the effect that the RCAM is more rigorous than CAM. As a result, the Board believes that the continued operation of CAM suggests that Enbridge and EI's commitment to the RCAM methodology will be tempered. There is also the potential for an adverse financial impact on Enbridge if it finds it must make budget reductions elsewhere to make "scorecard" targets and payments to EI in accordance with CAM. The Board will not establish the variance account proposed by Schools, but this is an area that is of interest to the Board and one which the Board will monitor going forward.

7.4

Enbridge Gas Distribution
2006 Actual EBIT Coverage of Interest

	OEB Normalized Allowed	Impact of Actual Weather	Weather Adjusted	Impact of Other Utility Actual Variances	Total Ontario Utility Results	[redacted]	St. Lawrence Gas Impact	Impact of Corporate Costs Not Recovered In Rates	Impact of Intercompany Financing & Other Corporate Items	Total EGD Legal Entity
Earnings Before Interest Expense and Income Taxes (EBIT) ($ millions)	346.87	(57.70)	289.17	7.81	296.98	[redacted]	2.73	(27.40)	100.59	372.90
Interest Expense ($ millions)	165.05	0.00	165.05	(3.66)	161.39	[redacted]	1.24	0.00	40.23	202.86
EBIT Interest Coverage (times)	**2.10**		**1.75**		**1.84**	[redacted]	**2.20**		**2.50**	**1.84**

Ontario Energy Board

FILE No. EB-2006-0034

EXHIBIT No. K7.4

DATE February 6, 2007

08/99

EBRO 479 K7.5

Ontario Energy Board
FILE No. EB-2006-0034
EXHIBIT No. K7.5
DATE February 6, 2007
decision - EBRO 479
08/99

7. COST OF CAPITAL

7.0.1 The Board has determined that, for the purposes of this Decision, the following issues need to be addressed:

- Financial Flexibility and Risk
- Capital Structure
- Cost of Long-Term Debt
- Return on Common Equity

7.0.2 As stated in Chapter 3 of this Decision with Reasons, the Board, for the purposes of determining the Company's cost of capital in the test year, has accepted 5.95 percent as the indicated cost of short-term debt.

7.0.3 The Board's findings on cost of capital, as set out in this chapter, are summarized in Appendix C.

7.1 FINANCIAL FLEXIBILITY AND RISK

7.1.1 Dr. Sherwin/Ms McShane contended that the financial risk of the Company has continued to rise. The narrowing of the spread between the allowed utility return on equity and the embedded cost of debt, and the earnings shortfall have in their opinion contributed to a decline in utility interest coverage and limited the Company's financial flexibility. This view was also supported by another Company consultant, Mr. Lackenbauer, who testified that the existing common equity ratios and high level of debt are "endangering" the credit ratings and financial flexibility of the Company. Consumers Gas noted that credit rating agencies have set 2.5 times interest coverage as a general benchmark in assessing a class "A" rating, and that Canadian Bond Rating Services Inc. had indicated that interest coverage ratios would need to improve for the Company to maintain current debt ratios.

7.1.2 Consumers Gas maintained that its financial flexibility has been affected by the shortfall in earnings experienced in fiscal 1991 and 1992 and the decline in interest coverage ratios. The Company stated that it was unable to access the long-term debt market between April 1991 and April 1992. It requested that the Board give it flexibility in its equity ratios and an adequate equity return.

7.1.3 Dr. Sherwin/Ms McShane maintained that there was no material chang[illegible] business risk since E.B.R.O. 473.

Positions of the Parties

7.1.4 Board Staff submitted that the Company's financial risk has not changed substantially from fiscal 1992 to justify either an increase in the return on equity or the equity ratio for fiscal 1993. Dr. Winter testified that the issue test provisions would not significantly constrain the Company's access to debt markets. He indicated that, for fiscal 1994, at a 35 percent equity ratio, $100 million in debt could be raised in the first month under the issue test, assuming an interest rate of nine to ten percent and an achieved return on equity of ten percent. Board Staff argued that even a 12 percent allowed return would result in a times interest earned ratio of 2.11, which would be higher than under the rates of return approved by the Board for fiscal 1991 (2.02), though not quite as high as fiscal 1992 (2.15). It submitted that the risk of a reduced credit rating in 1993, barring other factors such as weather and a severely depressed economy, is highly unlikely.

7.1.5 IGUA contended that the submissions of the Company relating to a decline in credit rating are "scare tactics", and submissions based on such "fear-mongering" evidence should be rejected as being unreasonable and without merit.

7.1.6 Both IGUA and CFBA/OCAP agreed that there was no material change in business risk since E.B.R.O. 473. However, Dr. Winter concluded that business risk has declined.

Board Findings

7.1.7 The Board has taken into account all the evidence, testimony and arguments of the parties with respect to the impacts of its decisions and the Company's need for financial flexibility. The Board, again, appreciates the assistance which the parties have provided through their efforts to instill objectivity into what is a highly subjective area of analysis and forecasting.

7.1.8 The Board finds that the overall financial and business risk exposure for fiscal 1993 is similar to that which existed in fiscal 1992.

7.2 CAPITAL STRUCTURE

7.2.1 Consumers Gas was reorganized to effect the transfer of the business activities and assets that were not part of its Ontario gas distribution and storage business to British Gas Holdings at fair market value. This reorganization was completed by February 1992, with an effective date of January 31, 1992.

7.2.2 In E.B.R.O. 473 the Board found the common equity component for the Company to be a deemed 35 percent for the 1992 test year. Due to the reorganization, Consumers Gas requested an actual projected common equity ratio for the 1993 test year and thereafter. It maintained that using an actual common equity and not a deemed common equity ratio gives the Company the flexibility to adjust for changes in risk. Consumers Gas set an internal target for the common equity ratio over the next five years in the range of 35 to 37 percent to reflect the non-linear impact on the common equity ratio of periodic common equity issues. It specifically proposed a capital structure that contains a projected actual ratio of 35.51 percent.

Positions of the Parties

7.2.3 Dr. Winter agreed with the Company's original proposal for a projected actual equity ratio of 35.5 percent. Board Staff submitted that the Board should approve a projected actual equity ratio for the test year but that it should be no higher than the current deemed equity ratio of 35 percent. Board Staff maintained that the deemed equity ratio of 35 percent remains appropriate as the risk of the utility has not changed substantially over the past year. Dr. Winter had suggested that a range of 34 to 36 percent would permit adequate access to debt markets, and that the Company's proposed upper limit of 37 percent was excessive. Board Staff submitted that the Board should not comment on the five year target ratio and expressed some concern that approval of a range would lend itself to an increase in the equity component of the capital structure. Further, Board Staff argued that, with a proposed rate base of $2 billion, a two percent range is unnecessary for purposes of financial flexibility and that there were no financial needs to justify a change to the debt-equity ratio.

7.2.4 IGUA did not support the change from a single point deemed common equity ratio to a projected actual equity ratio. It also submitted that the Board should not approve the target range concept as this will permit the

Company to "thicken" its equity and that there was no evidence to suggest that the current ratio of 35 percent was not reasonable. IGUA argued that the Board should continue to use a deemed common equity ratio of 35 percent. CFBA/OCAP recommended that the current capital structure be maintained and that the Company look to other financial instruments for financial flexibility if it finds itself unable to access the corporate bond market.

Board Findings

7.2.5 The Board notes that the immediate impact of the Company's proposal to employ an actual equity ratio would be an increase in the equity component. The Board finds that such a thickening is not justified by the evidence. The Board, therefore, rejects the proposed use of the Company's 35.51 percent actual equity as the equity component for ratemaking purposes in the fiscal year.

7.2.6 The Board deems a common equity ratio of 35 percent to be appropriate for Consumers Gas in fiscal 1993.

7.3 COST OF LONG-TERM DEBT

7.3.1 Consumers Gas requested that the Board accept 10.53 percent as the embedded cost of long-term debt for fiscal 1993. Although no incremental long-term debt issues were planned, the Company projected the replacement of previously issued debt with a $65 million debenture issue to be issued in March, 1993. The Company's forecast coupon rate on this issue is 9.10 percent, reflecting a spread of 85 basis points over its forecast of ten year Government of Canada bonds at 8.25 percent. After including issue costs, the effective cost rate of 9.24 percent has been included in the embedded cost of long-term debt calculation.

Positions of the Parties

7.3.2 Board Staff submitted that the coupon rate of the Company's debt issue would be 8.15 percent, not 9.10 per cent, based on Dr. de Bever's forecast of ten year Government of Canada bond yields (7.30 percent) and the 85 basis points spread. However, it estimated that the amount of the issue, compared to the total long-term debt of $1.1 billion, would have a minimal impact on the cost of capital. Therefore, Board Staff proposed that the cost of long-term debt submitted by the Company should be accepted by the Board.

7.3.3 IGUA supported the use of Dr. de Bever's estimates for Government of Canada bonds, and submitted that the $65 million debenture should use his ten year and over bond rate of 8.08 percent for fiscal 1993, plus a corporate premium of 85 basis points for a projected coupon rate rounded to nine percent.

Board Findings

7.3.4 The Board observes that the differences in the views expressed by the parties lead to results which would have only a minimal effect in the test year. The Board accepts the Company's assessment of the embedded cost of its proposed 1993 debenture issue at 9.24 percent and its forecast embedded cost of its total long-term debt at 10.53 percent for the test year.

7.4 RETURN ON COMMON EQUITY METHODOLOGIES

Long-term Canada Bond Rates

7.4.1 The Company's witnesses forecast a long-term Canada bond (30 year) rate of 8.75 percent for fiscal 1993 and Dr. de Bever forecast 8.2 percent.

7.4.1 The Company's witnesses forecast a long-term Canada bond (30 year) rate

7.4.2 Board Staff argued that 8.2 percent is reasonable given the continued poor prospect for economic recovery. IGUA preferred Dr. de Bever's rate over the higher rate of the Company's witnesses. It maintained that his long-term rate is consistent with the Bank of Canada policy to hold inflation near zero, and supported by the bridge year rates currently being experienced.

Comparable Earnings Test

7.4.3 This test estimates a return on equity for Consumers Gas by comparing the returns earned by a sample of low-risk industrials, adjusted to incorporate the specific risks of the utility over an appropriate time period.

7.4.4 The Company's witnesses applied the comparable earnings test to a sample of 28 companies for the period 1983 to 1991 to yield a 13.5 percent return. The result was then reduced by 30 basis points for the lower risk of the utility for a return on equity of 13.2 percent. They did not regard an adjustment for market-to-book ratios to be appropriate.

7.4.5 Dr. Winter selected 20 companies and used two business cycles, the historical business cycle, 1983 to 1991 and the current/prospective business cycle, 1985 to 1993, to produce returns of 12.45 percent and 11.62 percent respectively. He then reduced the results by 50 basis points for risk and 25 basis points for the market-to-book ratio to arrive at returns of 11.70 and 10.87. The adjustment for the market-to-book ratio is to compensate for non-balance sheet assets and inflationary distortions on book valued assets and to bring the Company's book rate of return closer to its opportunity cost of capital. The average of the results, 11.25 percent, was Dr. Winter's estimate for a fair rate of return under the comparable earnings test.

7.4.6 Board Staff, contending that information about current and proposed rates of return better reflects the rates of return available in the current business cycle, supported the inclusion of the 1993 returns. The Company argued that if weight is to be given to Dr. Winter's evidence, then 1992 and 1993 should be disregarded and only the "raw return" for the business cycle 1983 to 1991 (12.45 percent) should be considered. In other words, the Board should ignore the downward adjustment as the resulting return is below the cost of attracting capital.

7.4.7 IGUA submitted that the only thing the evidence showed was that the results of the test can differ. Therefore, it argued that the results of both the Company's and Board Staff's consultants should be considered. IGUA noted the midpoint of the two results is 12.2 percent. CFBA/OCAP maintained that the comparable earnings test should be adjusted by 100 basis points to better reflect the lower risk of the Company. Further, it argued that the market-to-book ratio adjustment should be even greater than Dr. Winter's 25 basis points. CFBA/OCAP suggested that a return of 11.4 percent would be a fair, generous and conservative rate of return for the Company under the test.

Equity Risk Techniques

7.4.8 This methodology compares the returns on equity investments to those of low risk long-term Canada bonds to derive the shareholder risk premium associated with equity investments. The forecast rate for long Canada bonds is added to the premium and the result is adjusted. Some of the parties noted that the cost of attracting capital has traditionally been adjusted by the Board at a market-to-book ratio of 115 percent for flotation cost, market pressure, and financial flexibility.

7.4.9 The Company's witnesses used a long Canada yield of 8.75 percent and relied on a risk premium of 3.5 to 3.75 percent for a cost of 12.375 percent. This was then adjusted for financial flexibility for a cost of 13.5 percent. Using Dr. de Bever's forecast of 8.2 percent, Board Staff noted that the Company's cost under this test would be reduced by 55 basis points to 12.95 percent.

7.4.10 Dr. Winter used Dr. de Bever's long Canada rate of 8.2 percent and a lower risk premium (1.91 to 2.5 percent) for a cost of equity, adjusted, in the range of 11.0 to 11.7 percent. He derived the lower specific risk premium by using a beta risk test. Board Staff submitted that Dr. Winter's range would provide a 2.9 to 3.5 percent return over the long Canada bond forecast. Board Staff argued that this is in line with Mr. Lackenbauer's testimony in support of a risk premium of three percent over government bonds. The Company submitted that Dr. Winter's reliance on beta in his calculation should not be accepted as it is an unreliable method for establishing a reasonable risk premium for the Company. Moreover, the Company argued that a risk premium of 1.9 to 2.5 percent will not meet investor requirements in that an investor would need a return of at least three percent over a long bond yield of 8.75 percent. When adjusted at 115 percent, this results in a minimum cost of equity of 12.8 percent.

7.4.11 IGUA, using Dr. de Bever's forecast for long Canadas and a market risk premium of 3.375 percent, submitted that the cost of equity would be 11.6 percent, when rounded. It calculated a market risk premium using the Board's previous findings on common equity (13.125 percent) and the cost of long-term debt (9.75 percent) in E.B.R.O. 473.

7.4.12 CFBA/OCAP maintained that the estimates of the equity market risk premium over long Canadas by all the witnesses were excessive. It recommended a lower market risk premium for an overall return of 11.95 to 12.15 percent. CFBA/OCAP also objected to the market-to-book value adjustment, and submitted that there was no evidence that supported the underestimation of the fair rate of return. It asked that the Board reconsider the use of the adjustment factor.

7.5 RETURN ON COMMON EQUITY

Positions of the Parties

7.5.1 The Company's witnesses gave equal weight to the comparable earnings and risk premium tests. It was their conclusion that the fair return on equity for the Company is 13.375 percent on an actual capital structure of 35.51 percent common equity. If the return were to be lower, they maintained that the common equity component would have to be higher.

7.5.2 Dr. Winter attached a 25 percent weighting to the comparable earnings test result of 11.24 percent and 75 percent to the equity risk premium point of 11.0 percent for a point estimate of 11.1 percent as the lower limit. He made no adjustment to the upper limit of the equity risk premium point of 11.7 percent. Board Staff submitted that, given Dr. Winter's recommendations, the decline in interest rates, the trend in the capita market and the rates of return available to potential investors since 1992, and the approved return in fiscal 1992, a return on common equity of 13.125 percent would be excessive for fiscal 1993. It maintained that the appropriate return is in the range of 11.7 percent to 12.5 percent. Board Staff recommended a rate of return of 12.5 percent on a 35 percent actual common equity ratio for fiscal 1993.

7.5.3 IGUA submitted that the Board should look at the 13.125 percent awarded in E.B.R.O. 473, and take into account the changes that have occurred in risks and economic conditions and the trends in equity awards granted by other regulators. Recent decisions in other jurisdictions have seen a reduction of about 125 basis points. IGUA pointed out that Consumers Gas' recommendation is only 67.5 basis points below the Company's recommendation in E.B.R.O. 473. IGUA, prescribing a 50/50 weighting to the results of the two tests (12.2 percent and 11.6 percent), submitted that the Board should find a rate of return of no more than 11.9 percent on a 35 percent deemed common equity ratio for fiscal 1993.

7.5.4 CFBA/OCAP submitted that changes in the money market, evidenced by the decrease in the yields of long-term Canada bonds, necessitate a lower rate of return. It recommended that the Board accept the lower range of Dr. Winter's recommendation and allow a return on equity of 11.0 percent.

7.5.5 The following table displays the submissions on the equity return requirement:

	Sherwin/McShane (Company)[1]	Winter	Board Staff	IGUA	CFBA
Comparable Earnings Test	13.2%	11.25%	-	12.2%	11.4%
Equity Risk Techniques	13.5%	11.0 - 11.17%	-	11.6%	11.95 - 12.15%
Return Recommendation	13.375%	11.1 - 11.7%	12.5%	11.9%	11%

[1] based on an equity component of 35.51%, all others were at 35%

Board Finding

7.5.6 After considering all the evidence and arguments in this proceeding, the Board finds that the Company's authorized fair rate of return for the test year on a deemed common equity component of 35 percent shall be 12.3 percent.

THE CONSUMERS' GAS COMPANY LTD.
CAPITALIZATION AND COST OF CAPITAL
For The Year Ending September 30, 1993
($ million)

PER COMPANY (1)

	Capital Structure	Ratios	Cost Rate	Return Component	Return
Long-Term Debt	1,145.6	55.11%	10.53%	5.80%	120.6
Short-Term Debt	89.1	4.29%	7.92%	0.34%	7.1
Preference Capital	105.9	5.09%	8.80%	0.45%	9.3
Common Equity	738.1	35.51%	13.375%	4.75%	98.7
Total	2,078.7	100.00%		11.34%	235.7

(1) *Includes Evidence Updates and Impact Statement Adjustments, but Excludes ADR.*

PER BOARD

	Capital Structure	Ratios	Cost Rate	Return Component	Return
Long-Term Debt	1,145.6	55.36%	10.53%	5.83%	120.6
Short-Term Debt	93.7	4.53%	5.95%	0.27%	5.6
Preference Capital	105.9	5.12%	8.80%	0.45%	9.3
Common Equity	724.3	35.00%	12.30%	4.31%	89.1
Total	2,069.5	100.01%		10.86%	224.6

K9.1

FRONTIER ✦ WOLSELEY
HVAC/R Group

February 6, 2007

Mr. Paul Green
Director, Market Development
Enbridge Gas Distribution

Dear Paul

I would like to extend my thanks on behalf of the management team of Frontier Wolseley HVAC/R Group for the presentation and update of the Energylink Program on January 16, 2007.

The innovative program linking consumers with professional contractors who provide industry leading products and services is viewed by our management team as a positive step for the HVAC industry in Ontario. The key feature is ensuring that all participating dealer / contractors meet the high standards set by Enbridge Gas Distribution for membership in this lead referral program. These standards are critical to the success of the program and dealer / contractor participation as the industry strives to ensure high quality workmanship and after sale service by all stakeholders. As we discussed the program aligns well with the 'Marketplace Distinction Program' developed by HRAC. Another key feature will be the membership registration process which will ensure that all contractors have equal access to the Enbridge program.

The management of Frontier endorses the Energylink Program and we will be encouraging our Comfortmaker, Keeprite and Heil Dealer / Contractors to register and participate in this program.

Thank you for the update and we look forward to the launch of the Energylink Program.

Regards

Greg Gamble
Vice President
Wolseley HVAC/R Business Group

Ontario Energy Board
FILE No. EB-2006-0034
EXHIBIT No. K9.1
DATE February 12, 2007
08/99

THERWOOD HEATING & COOLING
(Div of Therwood Contracting Ltd.)
29 Beech Street North,
Uxbridge, Ontario
L9P 1A9
(905) 852-5726 Fax (905) 852-0468

February 6, 2007

Murray Wilson
Enbridge Gas Distribution Inc.
498 Markland Street,
Unit 1,
Markham, Ontario
L6C 1Z6

Re: Energylink Program

Dear Murray,

The Energylink Program has been of great value to our company in the form of quality leads on sales of natural gas equipment and service.

Our customers are very happy to deal with a local contractor who has been pre-qualified from Enbridge.

I feel the program is a good thing for all parties concerned and should definitely be allowed to continue.

Yours truly,

Chuck Catherwood
Owner

CC/kcs

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Toronto, ON Canada
M1W 2P3
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FAX: 416-494-0565

January 19, 2007

Enbridge Gas Distribution
500 Consumers Road
North York, Ontario M2J 1P8

Attn: Paul Green – Director of Market Development

RE: ENERGY LINK PROGRAM – TRANE DEALER FEEDBACK (First 2 Months)

Paul, this is just a short note as a follow-up and Trane Dealer feedback related to your Presentation of the Energy Link Program to Manufacturers from last fall. My compliments to Enbridge to have an up front presentation of the program and asking the HVAC Manufacturers to offer input.

Trane Canada's very first Value is "We are driven by our customers". The ultimate customer in most cases is the homeowner. The Energy Link program provides the homeowner with a listing / method (call centre or on-line) to have their equipment serviced or new equipment installed by qualified HVAC Contractors in Ontario. The qualifications and agreements to be an Energy Link Contractor are excellent and this presents the best Contractors to the Homeowners in Ontario.

I have had feedback from many of our Dealers on the Program (for example – EN Blue/Ottawa – Buttons Heating/Markham – A Plus/Etobicoke), and most are pleased with the leads they have received and others have not seen a lot of sales leads, but again this program is only 2 months old, and they all believe this will develop over time, and be a very viable program.

The program guidelines you outlined in your presentation does fit with supporting the Industry. If what you presented and what has been implemented is your long term plan, and is not a restricted membership (you used the wording... inclusive not exclusive – if you qualify... you can be a member) then this will grow to be a very worthy homeowner / HVAC Contractor initiative.....well done.

Best regards,

Bruce L Shaw

Bruce L. Shaw
Trane Canada Sales Leader

LINK HEATING AND AIR CONDITIONING LTD.

R.R. #2, Beaverton, Ontario, L0K 1A0
Telephone: (705) 426-7831 - Toll Free: 1-877- 426-7831
Fax: 1-705-426-9549

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(705) 326-1648
Lindsay
(705) 878-1309

January 31, 2007

Don J. Armitage
Channel Consultant
Enbridge Gas Distribution Inc.
570 Neal Drive
Peterborough, ON
K9J 6X7

Dear Don,

I wanted to let you know that our experience with the Energy Link Program has been a positive one to date. The program is performing as advertised, and we have been receiving regular leads since the program went live.

Link Heating has been a long standing member of HRAC, and I am concerned about the Industry Coalition's position that the Energy Link Program is designed to allow Enbridge a level of control over independent contractor's operations. This has certainly not been our experience to date, and I do not support the coalitions condemnation of the program on that basis.

I sincerely hope that the program will continue to provide consumers with an Enbridge supported channel for locating qualified contractors. I am looking forward to continuing with the Energy Link Program and hope that it is expanded to offer participants the opportunity to utilize the gas bill for consumer financing.

Sincerely,

Rob deLaat
Link Heating

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ULTRA HOME PRODUCTS INC.
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Tel.: (905) 508-5252 / Toronto Line: (416) 526-0000
Fax: (905) 508-6218

February 1, 2007

Non HRAI
Member.

Enbridge Gas Distribution Inc.
EnergyLink Program,
1350 Thornton Road South
Oshawa, Ontario, L1J 8C4

Attn: Paul Green, Director, Market Development

Dear Paul,

As part of the Enbridge/EnergyLink program, Ultra Home Products would like to express the appreciation and successful launch of your program.

What we are finding out that since the deregulation of the gas utilities, the consumers are feeling the effects of bad business practices or lack of quality workmanship/services in this industry. The consumers have lost faith, essentially the HVAC contractors is receiving the third degree before booking any service or sales appointment.

For example, some HVAC companies would offer financing. You can pay it off early, but you would have to pay the full amount of interest and principal of the contract that you signed. Not even the banks will do this! Another example, a simple furnace clean and inspection ends up being a sale of a new furnace by fear mongering. Unfortunately, the HVAC trades association, TSSA and HVAC manufacturers/distributors have not been able to crack down and appropriately delegate and clean up the mess that was created.

In your case, Enbridge Gas could not direct the many thousands of calls you receive monthly. For Enbridge to tell its customers to "look in the phone book" for services related to gas is absolutely ridiculous. This would suggest that Enbridge does not care for the customers they supply gas to.

Now, with the launch of the Enbridge/EnergyLink program, we are definitely seeing a big change in consumer's behavior and believe me, it's a breath of fresh air. Customers are actually phoning back to thank us for a job well done. Before, they would tell us of the bad experiences, where they were left with no heat for over a week, wrong diagnostics and outrageous charges, but they had nowhere or anyone to turn to.

ULTRA
HOME PRODUCTS INC.

ULTRA HOME PRODUCTS INC.
137 Centre Street East, Richmond Hill, Ontario L4C 1A5
Tel.: (905) 508-5252 / Toronto Line: (416) 526-0000
Fax: (905) 508-6218

Ultra Home Products is pleased to participate in the Enbridge/EnergyLink program. The customers that are referred by Enbridge/Energylink are treated with the utmost respect and professionalism. In return, we are able to sell more gas products because of this program such as gas fireplaces, gas barbeques and gas appliances. Keep up the good work!

Sincerely,

Bob Jung
Director
Ultra Home Products

6

MEGACITY
Heating and Air Conditioning Ltd
611A Kennedy Road
Toronto, Ontario, M1K 2B2
(416) 286 5665

January 30, 2007

Darren Keates
Sales Channel Consultant
Enbridge Gas Distribution Inc.

Dear Darren,

Dave and I would like to thank you for introducing us to the EnergyLink Program. We have been up and running now for about a month and it has been great. Our very first quote resulted in an oil to gas conversion sale. The referrals are really helping to get us through the slow times and we are definitely looking forward to the busy time. Also, we look forward to the on bill financing (if approved). We truly believe that will benefit our customers tremendously, and give our sales team a great selling option. The EnergyLink program will definitely be a great tool in helping us to build a thriving, successful business.

I would like to bring to your attention one issue we have concerns about. As you may know Megacity Heating and Air Conditioning Ltd. is a member of H.R.A.I and as such, we are aware of the issue in front of the Ontario Energy Board about the EnergyLink program. From what we have heard and read, it seems that many H.R.A.I members are supporting this program, however, the HVAC coalition (HRAI Executives) do not. We would like to make it known that the coalition is fighting this program without our consent. We are very much in support of this program and strongly feel that it is a fabulous opportunity for the HVAC industry.

Sincerely,

Tammy Hawkins
Office Manager
MEGACITY Heating & Air Conditioning Ltd.

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February 1, 2007

To Whom It May Concern:

This letter is to express our great satisfaction with the new EnergyLink program. We know that it hasn't been off the ground for very long but we are very happy with the progress so far. This program is bringing in leads to Davenport-Campbell Co. Ltd. that we would not normally receive. Being a part of EnergyLink is helping our business in a very positive way and we are excited about our future with it.

Thank you,

Peter Bowker
President

KEEPRITE • SPACE-PAK • CARRIER • APRILAIRE • HONEYWELL

Since 1977
Button's Heating Inc.
www.buttonsheating.com

2721 Markham Rd. Unit # 31, Scarborough, Ontario. M1X 1L5
(416) 287-7863 (905) 432-1929 Fax: (416) 297-6977

January 31, 2007

Enbridge Gas Distribution
C/o Darren Keates

Button's Heating Inc. has participated in the past with many of the Enbridge programs with great success. We have participated with contractor rebates and with consumer rebates and incentives as well as being a part of the Enbridge pilot unlock program. Our history with Enbridge, as a gas supplier, has been one of a partnership in the industry. Currently we have become a qualified contractor with the Energylink program and are very enthusiastic about being part of the new generation of Enbridge contractors.

The "HVAC Coalition" has expressed their discontent with the new Energylink program, which we feel is unreflective of many HVAC contractors including our company. Moreover, the HVAC coalition remains vague on the specific issues they have regarding the new Energylink program even though we are members in good standing with HRAI. In general the HVAC coalition seems very unofficial. There is no official forum for their communication to contractors and no format for contractors to request information or comment on their issues. The HVAC coalition is therefore leaving the individual contractor virtually uninformed and unrepresented, contrary to what the coalition claims they are doing.

To summarize, Button's Heating Inc. looks forward to continued partnership with Enbridge Gas Distribution particularly our continued participation as an Energylink contractor and in future programs that will be mutually beneficial. The HVAC Coalition is not seemingly representative of Button's Heating Inc. at this time with respect to the new Energylink program.

Sincerely,

Joseph Button

Button's Heating Inc.

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January 30/07
Re: EnergyLink program progress

Attention: Darren Keates and EnergyLink team.
ADDRESS

Darren:

Thank you for your recent phone call inquiring as to how I felt the EnergyLink program was working out so far for our company and for the homeowners who contacted us through the program. You also wondered what I thought about HRAC challenging the EnergyLink program (in some respects) since we are a contactor member of HRAC in good standing. I have attended personally or had staff members attend the HRAC meetings first hand when EnergyLink was on the agenda. However in order to refresh myself on some of the forgotten details, I reviewed the letter from Nancy McKeraghan of the HRAC addressed to the O.E.B. This letter declared it was acting on behalf of the HRAC "And it's members" regarding the EnergyLink program. Upon review I would have to strongly disagree that it represents the opinion of ***this*** HRAC member contractor and from what I've seen at HRAC meetings it does ot seem to represent the majority of members there either.

Let me be clear in stating at the outset that I believe that the HRAC provides a valuable and effective forum for the HVAC industry in helping understand and resolve many issues industry wide. To this end I continue every year to be member of HRAC and on occasion provide additional financial contributions to help with issues I believe in as a member. I have for the most part felt that the HRAC has represented contractors, manufactures, etc.... quite well to date on past issues. At this time however we are having some difficulty in believing the same is true regarding HRAC's approach to the EnergyLink program. I'll just mention a few points as to why I feel at this time that HRAC isn't representing the interests of its local members but perhaps a more vocal and influential minority if its members and/or directors.

The first point would be perhaps to consider the number of HRAC member contractors who have shown their support for the EnergyLink program by signing up for it compared to how many of HRAC overall members who have made financial contributions to HRAC to oppose the EnergyLink program. In the past member contractors have shown their agreement and disagreement with industry issues that the HRAC were challenging by the amount of funds they contributed to that challenge. In short what percentage of member contractors put their money where their opinion was in joining HRAC in opposing the EnergyLink program. (We the contractor members don't know these numbers although HRAC claim to represent us in this issue in the letter to OEB) Unless this comparison is made in this basic form OR THE MEMBERS ARE GIVEN A CHANCE TO VOTE ON IT how can HRAC spokes persons claim to be representing the HRAC and its members or at least representing them on the basis of the percentage of contractors who support them in the challenge of EnergyLink.. Shouldn't HRAC at least let members know what these numbers are so they don't misrepresent our opinion without us even knowing the facts. If this isn't the approach taken perhaps they are representing a more vocal more powerful minority of it's members and/or directors rather than the rank and file contractor members. After all it is their stated mission to represent their members, I just wonder if that is true on a simple percentage of member support basis or not on this issue.

As to HRAC specifically challenging contractors ability to perform work for home owners and having it billed rough the Enbridge gas bill I would suggest there are various benefits to most parties concern. I think it would enefit the contractors, consumers, manufactures and economy. Already since being a part of the program my company has been able to help many homeowners find solutions for their home comfort, energy efficiency, and heating service challenges and questions. These homeowners have received professional advice promptly through the EnergyLink program. HRAC has a program designed for this purpose (Marketplace Distinction Program or MDP) which to date has almost been unnoticed by my company in regards to receiving customer contact specifics. This seems to be the consensus of several contractors I have queried in discussion while socializing at HRAC monthly meetings. There is no comparison. We have received 10 times as many in only 2 months with the EnergyLink program compared to the HRAC Marketplace Distinction Program over 2 years. We track our incoming leads that provide customer contact particulars by source as they are received so that we know the source of more than 90%.

Certainly some of this higher volume of referrals may be partly attributed to Enbridge's higher visibility, recognised name and billing and marketing system. HRAC seems to view this as a flaw perhaps lending to monopolization. I view it as effective usage of an existing infrastructure providing the O.E.B. assists in the watch dog roll to adjust or alter any EnergyLink processes which prohibit fair play for all contractors who meet the criteria. As to that criteria we have found that it has provoked us to further improve our company (at least in one area because we already meet or surpassed the other criteria) and we feel the public will be the beneficiary of these improvements. Shouldn't all contractors be subjected to such guidelines as TSSA registration, proper licensing, adequate insurance and monitored commitment to customers? I feel it raises the bar for all contractors as do the requirements of the HRAC and HRAI program and membership guidelines. I think that regardless who was administrating any such program should and would have similar guidelines. Furthermore, who would pay for the development and implementation to create a new infrastructure for a similar program? The obvious answer seems to be the HRAC and its members except that the HRAC's program has already proven to have little success. Further its members have already spoken by not oviding sufficient funding in the past to improve it or at present to join HRAC in their challenges to EnergyLink.

It feels like the HRAC directors and or spokes people are trying to force the members to accept their agenda rather than putting a yes/no vote to its members. The members have not had this opportunity and therefore have overwhelming shown their vote in the only two other means available to them. These are to join or not join EnergyLink and to contribute or not to contribute finically to the HRAC to challenge EnergyLink..

We have contributed a small amount to HRAC for this challenge because we believe the O.E.B should be involved to help bring balance to this program which should meet any reasonable expectations from HRAC. In conclusion I think EnergyLink has already proven in our company to provide a much needed forum for homeowners. Through EnergyLink homeowners have been able to reach an improved, qualified and licensed contractor to provide them the needed energy efficiency and home comfort information they requested. There have been about three dozen consumers we've been able to help in this way in the short history of the EnergyLink program. I think it is meeting an existing demand through an existing infrastructure and benefiting homeowners, contractors, the environment and the economy. EnergyLink personnel would be able to confirm or deny this, but I suppose that thousands have already been assisted since the inception of the EnergyLink program through it's full network of contractors.

Sincerely, Frank S Williams

Frank Williams
ales manager

YANCH
HEATING & AIR CONDITIONING

Wednesday, February 07, 2007

Enbridge Gas Distribution Inc.
Durham Region
Tel: (905) 436-7017
Fax: (905) 436-7029

Attention: **Neil Saunders, Channel Consultant**

Being enrolled in the ENERGYLINK program since December 2006, we would like to take the opportunity to express our feeling on the program.

We signed up for this program for all its benefits. We believe this program will be beneficial for the growth of customer awareness, the potential for the increase in sales for our Company, allowing Yanch Heating to expand our name to local natural gas customers. We also believe this program to be a great advantage for the homeowners to acquire quality HVAC contractors in there area.

We have found Enbridge and yourself to be exceptional in the launch of the program and on-going support. We are pleased to participate in this ENERGYLINK program with Enbridge.

Thanks

Chris Yanch
President

Barrie Location : 1148 Snow Valley Rd, Minesing, ON L0L 1Y0 (705)728-5406
Whitby Location: 2001 Thickson Rd S Unit#4, Whitby, ON L1N 6J3 (905) 579-5406

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Newmarket, Ontario L3Y 7M9
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Fax: (905) 952-0500

RECEIVED
AUG 15 2006
EnergyLink™
Paul Abate

Date: July 28, 2006

From: Aire One North

Attn: Mr. Paul Abate
Enbridge Gas Distribution
Energy Link Program
1350 Thronton Rd South
Oshawa, ON L1J 8C4

Re: Energy Link Program

This is to thank you to provide us with the opportunity of applying to express our interest to become a pre-qualified Energy Link contractor.

As a member of the Aire One group, Aire One North, has been trying to establish a solid relationship with it's customers in the Upper York Region since 2003. We have provided many households in this area with the benefits of utilizing natural gas as their primary source of heat as well as saving them the cost of heating air and water by offering more efficient solutions for their energy requirements.

I am confident that through this new program we will make the most of the tools you provide us to set an example of a win-win relationship between a natural gas provider and a heating contractor. Together we can more effectively increase market penetration of natural gas appliances especially high efficient energy-saving selections.

Sincerely,

Hossein Forouzan
M. Hossein Forouzan
General Manager
Aire One North

perry MECHANICAL INC.
285 BLOOR ST. WEST - BOX 220 - OSHAWA, ON L1H 7L1
TELEPHONE 905-725-3549 FAX 905-571-4388

Rec'd July 26/06

July 25, 2006

Expression of Interest:

Comments:

We are pretty excited about the new Enbridge Gas Distribution, Energy Link Program.

It opens up another avenue for HVAC and white goods referrals, which will increase business and promote load growth.

We are always looking for opportunities to promote energy efficiency and we have always promoted Enbridges Customer rebates and incentives.

As an added bonus the Energy Link Program will provide our employees with access to Enbriges Sales Campaigns, programs, sales tools and training.

We are very interested in exploring the option to finance on the Enbridge Gas bill and what is all involved in the process of managing these referrals.

We understand how important it is for customers to be referred to a reputable heating company as opposed to being instructed to check the yellow pages for a heating and cooling contractor. We feel this is a step in the right direction for Enbridge.

We are looking forward to learning more about this new business opportunity with Enbridge Gas Distribution.

Regards,

Gary McRae

Gary McRae
Director of Operations
Perry Mechanical Inc.

MANCINI HEATING & AIR CONDITIONING LTD.

July 27, 2006

RECEIVED
AUG 1 2006
EnergyLink™
Paul Abate

Enbridge Gas Distribution Inc.
1350 Thornton Road South
Oshawa, Ontario
L1J 8C4

Attention: Paul Abate

Dear Paul:

RE: ENERGYLINK PROGRAM

This is to inform you that Mancini Heating is a Full Service HVAC Company. We do Forced Air and Hydronic Heating, including Design, Custom Sheet Metal, Radiant Floor Heating, Snow Melt, various Gas Piping and Accessories. All our work is done in house with our vehicles, hourly Mechanics and Apprentices. We specialize in Renovation and Custom Homes.

We have been working closely with our Channel Consultant from Enbridge (Darren Keates), promoting various Enbridge programs with our customers whenever possible.

The Energy Link Program is a product that we at Mancini Heating, would be proud to promote and participate in.

Yours truly,
MANCINI HEATING & A/C LTD.

Venanzio (Joe) Mancini
President

180 Winges Road, Unit #7, Woodbridge, Ontario L4L 6C6
Tel: (416) 249-5848 Fax: (905) 265-0048

Halton Peel Heating Inc.

279 Lakeshore Road East,
Mississauga, Ont., L5G 2K8
Tel: (905) 566-4646
Fax: (905) 486-0056

TECHNICAL STANDARDS & SAFETY AUTHORITY
TSSA
QUALITY ASSESSED
CONTRACTOR

Enbridge Gas Distribution Inc.
EnergyLink Program
1350 Thorton Road South
Oshawa, ON
L1J8C4

RECEIVED
AUG 11 2006
EnergyLink™
Paul Abate

Attention : Mr. Paul Abate

I was most pleased to be informed of this new program. As a company that prides itself on it's customer service, Halton Peel Heating welcomes the opportunity to work with your organization and anticipates the relationship will be of benefit to all concerned.

Thank You
R.Morgan

AF AIR FLEX HEATING & COOLING LTD.

3252 Lawrence Ave. East
Toronto, ON M1H 1A4
Tel.: (416) 439-7155
1-888-670-6930
Fax: (416) 439-0376

RECEIVED
AUG 11 2006
EnergyLink™
Paul Abate

July 28th, 2006

Enbridge

Re: EnergyLink Program—Expression of Interest

We would like to express our interest in the program; Air Flex would welcome the opportunity to partner with Enbridge in providing quality services to those clients requesting our services.
At Air Flex Heating & Cooling Ltd we always strive to provide quality service and expert workmanship and would use this opportunity to continue delivering value to our customers.

We truly believe that this is an excellent idea and that it will be beneficial to clients who would be utilizing the link.
We hope to hear from you soon and also hope the program will be implemented without delay.

Thank you,

Lindon Martin

We take your comfort to heart.

BBB Toronto member
Metropolitan License H16265
Authorized Natural Gas Contractor

T.H. OLIVER
SINCE 1924
HEATING & AIR CONDITIONING INC.
"It's your comfort we're after"™
Carrier®

136 Wellington Street E., Unit #4, Aurora, Ontario L4G 1J1 Tel: (905) 727.4258 1.866.727.4258 Fax: (905) 727.7164

RECEIVED
AUG 10 2006
EnergyLink™
Paul Abate

August 3, 2006

Paul Abate
Enbridge Gas Distribution Inc.
EnergyLink™ Program
1350 Thornton Road South
Oshawa, ON L1J 8C4

Dear Paul:

Thank you for your consideration with regard to the new Enbridge EnergyLink™ Program. I value and appreciate the opportunity to participate in your new program. We have used your past and current retail coupon programs with great success and support. I have read with interest the program overview and feel strongly that this will benefit our business. Our working natural gas retail showroom will provide a strong platform to promote and sell natural gas products and services. We are excited at the possibilities and look forward to building a mutually rewarding future in value-added natural gas products and services. Please feel free to contact me directly to discuss this in greater detail as required.

Thank you,

Steven K. Desjardins
Manager of Operations / Owner

BEYOND YOUR EXPECTATIONS
Comfort Zone 21°
HEATING AND
AIR CONDITIONING

Friday July 28, 2006

RECEIVED
AUG 8 2006
EnergyLink™
Paul Abate

Mr. Paul Abate
Enbridge Gas Distribution Inc.
EnergyLink Program
1350 Thornton Rd. South
Oshawa, ON
L1J8C4

Dear Mr. Abate,

Thank you for providing Comfort Zone 21 Degrees with the great opportunity of joining the team at Enbridge. We are willing and eager to participate in your EnergyLink program starting this December.

John Chitussi has provided us with great representation of your company over the years. He is helpful and easily available if we need any assistance or information. We look forward to doing more business with Enbridge in the future.

At Comfort Zone our main focus is customer service and we work hard everyday to exceed our customers' expectations. If selected for your program we will continue to strive for customer satisfaction excellence and provide a professional, dependable representation of your HVAC referral program.

We have attached our Expression of Interest form and we look forward to hearing from you.

Sincerely,

Stewart Paterson
Comfort Zone 21 Degrees
President

46 Fieldway Road, Unit 6, Toronto, Ontario • M8Z 3L2
Tel: 416.233.2100 • **Toll Free:** 1.866.244.5537 • **Fax:** 416.231.5880 • www.comfortzone21.com • **email:** comfortzone21@rogers.com

11

JRL HVAC Inc.
278 Rutherford Rd S. Brampton, ON L6W 3K7
Phone: (905) 457-6900 Fax: (905) 457-5429

Direct Energy
Essential Home Services

RECEIVED
AUG 8 2006
EnergyLink™
Paul Abate

August 02, 2006

Enbridge Gas Distribution Inc.
EnergyLink Program
1350 Thornton Road South
Oshawa, ON
L1J8C4
Attn: Mr. Paul Abate

RE: EnergyLink Expression of Interest

Dear Mr. Abate,

Enclosed please find two copies of the Expression of Interest for the EnergyLink Program. JRL HVAC Inc. is very interested in the program and would like the opportunity to find out more details as things unfold.

We are a Direct Energy Franchisee for the Mississauga/Brampton area currently handling approx 45,000 service calls annually in addition to installing approx 1500 furnace and air conditioning systems during the same period. We are very committed to achieving high levels of Customer Service for Sales and Service. We share many of the key success indicators you mention on page 7 of the Expression of Interest document such as Customer follow-up within 24 hours and handling complaints effectively and in a timely manner to name just a few.

I see the Program as an opportunity to support your initiatives while referring the Customer to the best qualified participants in the industry. This is a win-win-win for everyone, especially for the Customer.

I believe we share similar company values that focus on delivering the best possible products, services and support available. We are professional, honest and accountable. With over 30 technicians and trucks on the road on a daily basis, we are large enough to support your initiatives and yet small enough to demonstrate flexibility in understanding our Customer's needs.

I look forward to finding out more about the EnergyLink Program.

Please let me know if I can be of assistance in helping to guide and shape this exciting NEW venture.

Thank you in advance for your consideration to our Expression of Interest.

Regards,

Neil Kelly
Director, Sales Operations
JRL HVAC Inc.
278 Rutherford Rd S
Brampton, Ont.
L6W3K7

20

K9.2


Link
Energy
ENBRIDGE
enbridge.com/energylink
Your link to approved natural gas contractors
PATTISON
10/02/2007

Ontario Energy Board
FILE No. EB-2006-0034
EXHIBIT No. K9.3
DATE February 12, 2007
08/99

K9.3
12. Feb. 2007

ENBRIDGE

Need a Contractor?

Finding a good heating, ventilation and AC contractor

We give you some tips on how to find a contractor and some important considerations for your decision.

How do I find a contractor?
How do I know if that contractor is qualified to install or work on natural gas equipment?
How do I ensure I'm dealing with a reputable business?
What might a contract from a contractor include?

Energy

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How do I find a contractor?

You can find a reputable contractor through EnergyLink™, a new Enbridge service which connects customers with Enbridge approved contractors. These contractors can help you if you're looking to buy, install or service a natural gas appliance. It's a convenient, easy to use service which helps you find a qualified contractor in your area.

If EnergyLink™ contractors are not able to address your specific HVAC needs, you have a number of other options to help you find a contractor:

- Visit the Heating, Refrigeration and Air Conditioning Contractors of Canada website
- Check your local telephone directory, newspapers, TV, and radio ads
- Ask your neighbours for recommendations
- Contact stores that sell natural gas equipment.

How do I know if a contractor is qualified to install or work on natural gas equipment?

Ask prospective contractors which trade associations they are affiliated with. In Ontario, qualified HVAC contractors must be licensed and registered with the Technical Standards and Safety Authority (TSSA), the province's fuel safety watchdog.

To verify a contractor's registration:

- Call TSSA at (416) 325-2000. Outside Greater Toronto 1-800-268-1142

How do I ensure I'm dealing with a reputable business, and what are some other considerations?

Ask the contractor the following:

- What trade associations are they affiliated with?
- How long have they been in business?
- What is the warranty and maintenance coverage on equipment and labour?
- How much liability insurance coverage does the contractor carry?
- Does the contractor offer financing or leasing programs?
- Is 24-hour service available, ie., if your furnace stops working in the middle of a cold winter night?

Ask questions and compare not only their prices but the contractor's experience and services offered. Ask each contractor for references from previous customers in your area, and call to see if they were satisfied with the work.

Consider getting three written quotes outlining the work to be done and the total price. Remember that the lowest price does not always provide the best value. Once you've chosen your contractor, insist on a detailed and signed contract. Before signing a service contract, be sure you read and understand all of the terms and conditions, including the fine print.

What might a contract from a contractor include?

When providing a written quote, the contractor should provide details regarding:

- Job start date
- Estimated completion date
- Payment policy
- Warranty details on parts and labour
- A guaranteed price including all parts, labour and taxes

In addition, they should be able to provide product information, ie., manufacturer brochures for the new gas appliance(s) they are installing.

K9.4

Filed: February 12, 2007
EB-2006-0034
Exhibit K9._____

Consolidated Residential Fuel Switching Initiatives

(all data from Exhibit K6.3, pages 3 and 13)

Item	Direct Programs				EnergyLink Programs				All Programs			
	Volume	Participants	NPV	TRC	Volume	Participants	NPV	TRC	Volume	Participants	NPV	TRC
1 ***High Efficiency Furnaces***	6.49	3,174	$2.31	$22.95	2.45	1,200	$0.87	$8.68	8.94	4,374	$3.18	$31.63
2 ***ECM***	0.33	5,000	$0.19	($0.54)	0.02	262	$0.01	($0.03)	0.35	5,262	$0.20	($0.57)
3 ***Mid Efficiency Furnaces***	0.30	123	$0.11	$1.11	0.00	0	$0.00	$0.00	0.30	123	$0.11	$1.11
4 ***Fireplace***	1.77	5,303	$0.61	($6.12)	1.77	5,303	$0.61	($6.12)	3.54	10,606	$1.22	($12.24)
5 ***Grill/BBQ***	0.07	1,477	$0.01	($0.18)	0.00	0	$0.00	$0.00	0.07	1,477	$0.01	($0.18)
6 ***Range/Dryer/Front Load Washer***	1.26	12,966	$0.49	$0.03	1.26	12,966	$0.49	$0.03	2.52	25,932	$0.98	$0.06
7 ***Low Income Water Heaters***	0.78	1,150	($0.56)	$0.38	0.00	0	$0.00	$0.00	0.78	1,150	($0.56)	$0.38
8 ***Interior Construction Heat New***	10.60	18,644	$0.80	$5.19	0.00	0	$0.00	$0.00	10.60	18,644	$0.80	$5.19
9 ***Interior Construction Heat Comm.***	0.37	107	$0.00	$0.35	0.00	0	$0.00	$0.00	0.37	107	$0.00	$0.35
10 ***Fuel Switching Water Heaters***	1.03	1,518	($0.06)	$1.79	0.68	1,000	($0.04)	$1.18	1.71	2,518	($0.10)	$2.97
11 ***Water Heaters***	0.99	2,500	$0.26	$1.49	0.59	1,500	$0.16	$0.89	1.58	4,000	$0.42	$2.38
12 ***Outdoor Living/Garage Heating/Pool Heating***	0.33	550	$0.04	($1.11)	0.42	700	$0.05	($1.41)	0.75	1,250	$0.09	($2.52)
Totals	**24.32**	**52,512**	**$4.20**	**$25.34**	**7.19**	**22,931**	**$2.15**	**$3.22**	**31.51**	**75,443**	**$6.35**	**$28.56**

Ontario Energy Board
FILE No. EB-2006-0034
EXHIBIT No. K9.4
DATE February 12, 2007
08/99

K9.5
12. Feb. 2007

K9.5

EBRIDGE CONTINUED

E-Bridge Volume 22 | January 2007

Enbridge helping households and small businesses locate qualified and trusted contractors

Enbridge Gas Distribution has launched a free and convenient referral service to help residential and small business customers find natural gas contractors in their neighbourhoods.

EnergyLinkTM connects customers with local Heating, Ventilation and Air-Conditioning (HVAC) contractors for the purchase and installation of natural gas products such as furnaces, fireplaces and water heaters.

"We are launching EnergyLinkTM because we want to make it easier for our customers to find qualified natural gas contractors," says Lino Luison, Vice President, Enbridge Gas Distribution. "The program will help our customers make informed purchasing decisions. Making it easy and convenient to buy and install natural gas appliances will help us grow our business and improve customer satisfaction."

EnergyLinkTM contractors have made a commitment to meet Enbridge Gas Distribution's standards for professional qualifications, safety and customer service. Enbridge Gas Distribution does not provide HVAC products or services. EnergyLinkTM contractors will be responsible for all products or services provided to customers as a result of referrals generated by the EnergyLinkTM program.

EnergyLinkTM is easy to use. Customers interested in finding an EnergyLinkTM contractor can visit www.enbridge.com/energylink or call 1-888-GAS-8888 to get started.

Feedback   Return to E-Bridge

Ontario Energy Board
FILE No. EB-2006-0034
EXHIBIT No. K9.5
DATE February 12, 2007.
08/99

K9.6

500 Consumers Road
North York ON M2J 1P8
Canada

Patrick Hoey
Director, Regulatory Affairs
Tel 416-495-5555
Fax 416-495-6072
Email patrick.hoey@enbridge.com

ENBRIDGE

K. Lakatos-Hayward
P. Green
B. Neiles
L. Luison
B. Betts
M. Suckling
P. Hoey

VIA COURIER

Ontario Energy Board
FILE No. EB-2006-0034
EXHIBIT No. K9.6
DATE February 12, 2007

2006-08-08

Mr. Howard Wetston Q.C.
Chair
Ontario Energy Board
2300 Yonge Street
Toronto, Ontario
M4P 1E4

Re: HVAC Letter, dated August 1st, 2006 and Enbridge Gas Distribution's EnergyLink^{TM} Program

I am writing to respond to the letter from HRAC dated August 1st, 2006 on Enbridge Gas Distribution's ("Enbridge") EnergyLink^{TM} Program, in order to correct some serious inaccuracies and distortions, and to offer our recommendations for your consideration.

First and foremost I want to clarify that the EnergyLink^{TM} Program is a market facilitation program, connecting customers with natural gas contractors and appliance retailers that Enbridge plans to launch in December 2006. In the 2006 rate case, we presented substantial evidence regarding Enbridge's plans to create a formalized channel partner program to address the increasing growth challenges faced by the Enbridge, including high energy prices, declining average-uses, declining market penetration in natural gas water heaters and increased threats in lost market share in fireplaces, dryers and ranges. Specifically, we stated our intention was to strategically partner with contractors, retailers and manufacturers to grow natural gas throughput, increase DSM opportunities and to increase customer satisfaction. During the 2006 rate case, neither HRAC, HVAC or any other intervening group indicated any concerns with our plans. We are, therefore, confused why it has become an issue at this late juncture.

Enbridge has tried to impress upon the Board and intervenors the need for it to be proactive in dealing with the declining average-use of natural gas. While part of the decline results from the positive influence of DSM programs, another part is due to a lack of promotion of natural gas as a fuel and natural gas appliances as alternatives to electric, oil and propane equipment.

The Board has many times reminded Enbridge that it has a responsibility to its ratepayers to maximize the efficient use of its assets. If Enbridge can not sufficiently inform consumers about their decisions when energy installations are being made, then we are further limited in our ability to maintain an appropriate volume of natural gas consumption, which results in a higher volumetric price or distribution rate.

As well, the Ontario government has a stated policy of conserving electricity and part of that program is to encourage Ontario consumers to choose appliances that are not electric. Consumers have and will continue to choose alternative fuel source appliances, mostly electricity, if they believe they are not provided with the correct information and service at the time they are making those fuel choice decisions.

In addition to our utility responsibilities, Enbridge strongly believes that the EnergyLink™ Program is a program that our consumers and the market place want, reflecting feedback received from customers, contractors and natural gas appliance retailers.

Perhaps more importantly, the EnergyLink™ Program addresses customer's unmet needs, a point that is not at all addressed by HRAC. Customers do not know what HRAC is or its "Marketplace Distinction Program." In fact, many members of HRAC themselves are unaware of this "Marketplace Distinction Program." Market research clearly shows that customers do not know where to turn regarding assistance on natural gas energy solutions and expect their utility to play a role in helping them connect to those who provide those services – hence EnergyLink™. The program has been designed to increase customer choice. Enbridge does not direct the customer referrals – rather it is the customer who chooses which EnergyLink™ participant they want to hear from.

Therefore, Enbridge is at a loss to understand the concerns expressed in HRAC's letter about the EnergyLink™ Program, when the main focus is in meeting natural gas customer needs in our franchise area.

Enbridge has some specific comments regarding material raised in HRAC's letter. Contrary to what HRAC would indicate, contractors have been extremely positive towards the EnergyLink™ Program and intend to join not because they feel obliged to, but because they want to. Indeed, some contractors have indicated to us that they will not join the program, not because of any concerns over whether Enbridge should run a program such as this one, but rather because the program would not provide them with sufficient referrals. This position is hardly indicative that the program will create market power/control or will force contractors to join. Clearly, contractors will only join if it is in their best interest to do so. Nonetheless, the response to the EnergyLink™ Expression of Interest has been overwhelming. Over 150 contractors to date have expressed their interest, despite numerous efforts and letter campaigns by HRAC to discourage their members from participating. Of the 150 positive responses, approximately one-half of these contractors are members of HRAI, also indicating that there are many other contractors out there who are not members of HRAI. We also note that many contractors have sent Enbridge accompanying letters of support for the program.

Enbridge has been co-operative with HRAC and spent considerable time, effort and expense, not only to explain the program in detail, but more importantly to change our program to accommodate certain concerns of HRAC and ensure that the program is aligned and supports their "Marketplace Distinction Program." While Enbridge did not accommodate all of HRAC's suggested changes, we feel at this point that Enbridge has been more than reasonable in its efforts.

I would also like to correct for the record statements made to you regarding Enbridge's Industry Council. HRAC have stated that "the utility was told in no uncertain terms that the program would be damaging to the industry". More accurately, response from the Industry Council was mixed. Some contractors expressed support for the program and subsequently have submitted their Expression of Interest, while others have not, a position we respect.

To be clear, the EnergyLink™ Program is not a return to the days of the Authorized Dealer Network. Rather it represents a forward-looking comprehensive strategy to grow natural gas throughput and to increase customer satisfaction. It is an industry inclusive strategy that addresses all end uses and market players - HVAC contractors, retailers of natural gas appliances and equipment manufacturers. In designing the program we have been put in many safeguards to ensure that the program is fair and equitable and the process transparent.

We believe that HRAC's letter is yet another tactic to create uncertainty and confusion in the market place to reduce support for this program and to use the Board to promote their own commercial activities.

Enbridge feels strongly that:

1) This program is appropriate within our role as a natural gas utility;
2) The program was fully presented in our recent rate hearing, without issue;
3) We are currently challenged to our very limits to meet all of the regulatory responsibilities;
4) The issue raised by HRAC has no bearing or material consequences on the establishment of rates for the 2007 test year;
5) We need some flexibility to maximize the efficient growth of natural gas volumes in our franchise area, or suffer the consequences of declining average use and corresponding increasing distribution rates.

Enbridge recommends that the requests included in HRAC's letter be dismissed. If the Board feels that it has insufficient information to dismiss it now, then it could be dealt with through a written process outside of a rate application process.

Yours truly,

Patrick Hoey
Director, Regulatory Affairs

cc: Nancy McKeraghan, HRAC
Martin Luymes, HRAI

K9.7

Ontario Energy Board
P.O. Box 2319
27th. Floor
2300 Yonge Street
Toronto ON M4P 1E4
Telephone: 416- 481-1967
Facsimile: 416- 440-7656
Toll free: 1-888-632-6273

Commission de l'Énergie de l'Ontario
C.P. 2319
27e étage
2300, rue Yonge
Toronto ON M4P 1E4
Téléphone; 416- 481-1967
Télécopieur: 416- 440-7656
Numéro sans frais: 1-888-632-6273

Ontario

Compliance Office

RECEIVED
NOV 09 2006
DIRECTOR, REGULATORY AFFAIRS

cc. T. Persad
K. Lakatos-Hayward
P. Green
R. Neiles
Luison
Healy

Ontario Energy Board
FILE No. EB-2006-0034
EXHIBIT No. K9.7
DATE February 12, 2007
08/99

November 8, 2006

Mr. Mike Latreille
Chair, HRAC
2800 Skymark Ave., Building 1, Suite 201
Mississauga, ON
L4W 5A6

Dear Mr. Latreille:

I am writing in response to your letter of October 24, 2006 addressed to Mr. Howard Wetston, Chair of the Ontario Energy Board, on behalf of the Heating, Refrigeration and Air Conditioning Contractors of Canada ("HRAC"), in which you expressed your continued concerns in relation to Enbridge Gas Distribution Inc.'s ("Enbridge") proposed EnergyLink program.

I would like to begin by first expressing our sincere apologizes for the delay in responding to your initial letter of August 1, 2006. However, on behalf of Mr. Wetston, I am pleased to provide a response based on a review of the issues raised and the Board's regulation of natural gas matters in general.

I understand that HRAC is concerned that the EnergyLink program represents an attempt by Enbridge to control the HVAC market, and that the utility's domination of the market places pressure upon HVAC contractors to participate in the program, whether or not they wish to do so. In your most recent letter, you claim that Enbridge employees are offering contractors utility financing, access to the utility bill and other services that you believe should be subject to Board approval.

The Compliance Office has reviewed the EnergyLink program. Based on its discussions with Enbridge staff, it appears that the program provides information on natural gas appliances, in addition to contact details for a number of gas retailers and contractors. It is offered without cost to customers or participating retailers/contractors; and referrals are on a rotating basis so every retailer/contractor has an equal opportunity of being contacted.

The Board's regulation of natural gas matters includes approving rates charged by natural gas utilities and approving pipeline construction, terms and conditions of franchise agreements, certifications of public convenience and necessity, storage facilities and utility ownership changes. Section 44 of the *Ontario Energy Board Act, 1998* (the "Act") also permits the Board to make rules governing specific conduct of a gas distributor, gas transmitter or storage company. Under the authority of section 44 of the Act, the Board developed the Gas Distribution Access Rule (the "GDAR") which establishes conditions of access to gas distribution services provided by a gas distributor; and further establishes rules governing the conduct of a gas distributor as such conduct relates to a gas vendor.

In the past, the establishment of rules under the Act has been in response to identified trends in consumer and market issues. While you have noted potential implications of the program, at this time, it is unclear whether the program has created or will create a situation which will necessitate the establishment of a rule to limit a gas distributor's involvement in HVAC related matters. Furthermore, at this time, it does not appear that the EnergyLink program is outside of the requirements of the GDAR or any other regulatory parameters within which Enbridge is permitted to distribute natural gas in Ontario.

As you know, the Board approves rates charged by natural gas utilities through oral and written hearings. If you believe that there is evidence to demonstrate that the EnergyLink program may have cost or revenue implications for either Enbridge or its customers, I encourage you to present your concerns through the rates hearing processes for further consideration.

If you wish to discuss the specific services being provided that you believe are subject to Board approval, I would be happy to meet with you. Please contact Susanna Beatrice-Gojsic, Advisor – Compliance Office, to arrange a suitable meeting time at 416 440 7741.

Thank you for bringing your concerns to the attention of the Board.

Sincerely,

Brian Hewson
Chief Compliance Officer

Cc: Howard Wetston, Chair
Patrick Hoey, Enbridge Gas Distribution Inc.
Martin Luymes, HRAI

K 9.8

EB-2006-0034

ONTARIO ENERGY BOARD

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 Enbridge Gas Distribution Inc. for an Order or Orders approving or fixing just and reasonable rates and other charges for the sale, distribution, transmission and storage of gas commencing January 1, 2007.

EXHIBITS FOR CROSS-EXAMINATION BY UNION ENERGY LIMITED PARTNERSHIP

ITEM
EnergyLink Contractor Guide (Exhibit No. KT2 - Exhibit of Enbridge at Technical Conference of January 10, 2007)
EnergyLink Program (Exhibit I-26-4, attachment 2)
Printout from HRAC Site
Business Case for EnergyLink Program (Exhibit I-26-10, attachment 1)

OTT01\3142288\1

Ontario Energy Board
FILE No. EB-2006-0034
EXHIBIT No. K 9.8
DATE February 12, 2007.
08/99

Ex AT #2
Energy Link
Contractor audit

ENBRIDGE

December 6, 2006

Dear EnergyLink™ Program Participant,

Welcome to the EnergyLink™ Program and congratulations. We anticipate it will make a positive enhancement to your business. Since you've been pre-screened by Enbridge, you'll be recognized by Enbridge customers in your area as an HVAC contractor they can feel comfortable calling – whether it's to recommend, sell or install a natural gas furnace or water heater, or to ask your advice about the most suitable natural gas products for their needs.

We trust that you are as excited as we are that you've been accepted as an EnergyLink™ Program Participant. It is extremely important to Enbridge that all the contractors and retailers who participate in the EnergyLink™ Program are highly reputable and reliable. Our customers rely on us to make sure they can rely on you. For that reason, we set a minimum criterion for all members, which you have reached.

Customers can count on EnergyLink™ to provide them with a referral to an independent, fully qualified contractor who has been pre-screened by Enbridge. You can count on us to refer our customers to you. And we can count on you to continue to provide the quality of service our customers would expect from a contractor approved by Enbridge. The EnergyLink™ Program will help keep customer satisfaction at the highest possible level, and that can only be good for your business and ours.

Please take a moment to read through this binder. You'll discover many ways you can benefit from membership in the EnergyLink™ Program. We are confident your participation in the Program will introduce you to new customers who will now think of you as their EnergyLink™ contractor – the HVAC contractor they can rely on for all their natural gas needs.

Sincerely,

Paul Green,
Director, Market Development
Enbridge Gas Distribution

EnergyLink™

The Benefit of Membership

How EnergyLink™ works

Natural gas customers are often unsure about whom to turn to when it comes to buying, installing or servicing natural gas products and appliances. The EnergyLink™ Program provides our customers with a website and a phone line that will link them to natural gas contractors who have been pre-screened by Enbridge. A referral from EnergyLink™ will assure our customers that the contractor they're hiring is independent and fully qualified to sell, install or service natural gas equipment and products. Now that you are an EnergyLink™ Program Participant, they will look to you!

A link to new customers

Enbridge will refer natural gas customers to you through the EnergyLink™ Program.* There is no limit on the customer opportunities or referrals we will send to you. It will depend entirely on how many customers in your area access and take advantage of the EnergyLink™ Program.

Enbridge will promote EnergyLink™

The EnergyLink™ Program will be promoted to all Enbridge customers through a mix of advertising and bill insert initiatives. Both our current and new natural gas customers will be aware that they can now find reputable contractors in their area by contacting EnergyLink™ through its website or phone line. They will know that the contractors they are referred to through EnergyLink™ are pre-screened by Enbridge, and that they can count on those referrals to be reliable and trustworthy. Enbridge Gas Distribution will be investing to promote the EnergyLink™ website and toll free telephone number to link customers to your organization.

---

*Enbridge makes no commitments, warranties, guarantees or representations regarding the number of referrals a contractor may receive from the EnergyLink™ Program.

It's easy for new customers to find you

To find contractors in their area who have been pre-screened by Enbridge, our customers simply visit www.enbridge.com/energylink or call 1-888-GAS-8888. They will be presented with the opportunity to select up to three contractor referrals who meet their equipment request. As soon as a customer in your area requests a referral from EnergyLink™, you may be one of the contractors to whom they are referred.

Making EnergyLink™ Work for You

Our customers *want* referrals from us

Natural gas customers have been asking Enbridge to refer them to reputable contractors for years, but it has only recently become possible for us to do so. Knowing a contractor has been pre-screened by Enbridge is very important to our customers. They are often anxious about finding a reputable contractor who can advise, sell, install or service natural gas products and appliances. They see it – rightly – as an important undertaking. Consequently, our customers appreciate the reassurance that Enbridge knows and approves of the contractor they've chosen.

Making EnergyLink™ Work for You

Your customers *want* to know you're a member

You are now one of our Enbridge approved EnergyLink™ contractors – and your potential customers will want to know! To this end, we have developed marketing and sales tools for your company's use. Our advertising support can help you promote the fact you are an EnergyLink™ Program Participant; our sales tools will complement your efforts in reassuring your customers that they will save energy and money when they upgrade old furnaces or appliances to more energy-efficient natural gas products, or switch from electric or oil powered equipment to natural gas.

Take advantage of the advertising materials Enbridge offers

In the next tab, you'll find examples of support materials such as ad mats, vehicle and store window signage, and EnergyLink™ logo graphics. As well, there is a guide to help you understand the most effective way to adapt these materials for your company and the rules regarding their use.

EnergyLink™

Making EnergyLink™ Work for You

Take advantage of the sales tools Enbridge offers

As a member of the EnergyLink™ Program, you can access sales campaigns, tools, and training that were developed by Enbridge specifically for natural gas contractors and retailers. Simply call your Enbridge Channel Consultant for more information, or visit

www.enbridge.com/contractor

Click on the 'Contractors' log in and discover the many resources available from Enbridge that can help you grow your business.

EnergyLink™

Trademark Usage

Guidelines for EnergyLink™ Program Participants*

*Guidelines and scenarios for EnergyLink™ Program Participants when using any trademark of Enbridge Inc. or Enbridge Gas Distribution Inc. (together referred to as "Enbridge") or promotional materials provided by Enbridge relating to the EnergyLink™ Program. All use rights are strictly limited to EnergyLink™ Program Participants.

Please discuss your programs and ideas with your Enbridge Gas Distribution Representative as early in the process as possible so that they may facilitate the approval process as quickly as possible. You may refer to the Program Contacts section in this Guide for the Representative in your area.

Use of the EnergyLink™ Trademark and Logo

1. All advertising and promotional materials prepared by the Participant relating to or referring to the EnergyLink™ Program must be approved in writing by Enbridge. The Participant will submit drafts/scripts and final versions of all ads or promotional materials to the Enbridge Gas Distribution Representative in their area prior to production or distribution/release.

2. The Participant will only use the EnergyLink™ trademark, as a word or in the logo format or both, in a manner that has been approved by Enbridge in writing. Any permitted use of the EnergyLink™ trademark must be in the same or smaller font size and style than the balance of the document so it does not dominate the advertising and promotional materials prepared by the Participant.

3. The Participant will associate with the EnergyLink™ trademark any notice that Enbridge may require from time to time, which may include "TM" or "®" following the mark as stipulated by Enbridge and/or the legend "Trademark of Enbridge Gas Distribution Inc., used under license."

4. The EnergyLink™ trademark may not be used in association with any product or service other than those specifically covered by the Program Schedule(s) executed by Enbridge and the Participant in the Participant's Program Agreement.

Use of EnergyLink™ Program Promotional Materials

The Participant shall obtain the prior written approval of Enbridge to use the EnergyLink™ Program promotional materials prepared by Enbridge in support of the EnergyLink™ Program. Requests shall be submitted to the Participant's Enbridge Gas Distribution Representative prior to production or distribution/release. In addition, use of EnergyLink™ Program promotional materials shall be subject to such additional use restrictions as may be established by Enbridge from time to time.

Use of the Enbridge Trademark and Logo

The Participant may not use the ENBRIDGE trademark or "swirl" logo, other than in promotional materials supplied by Enbridge or Enbridge's approved supplier(s). In the event that Enbridge provides the Participant with promotional materials containing the ENBRIDGE trademark and/or "swirl" logo, the Participant shall not alter such promotional materials in any manner and shall strictly use such promotional materials in accordance with the use restrictions established by Enbridge from time to time.

General Restrictions

1. The Participant may only use approved marketing or promotional materials in connection with the EnergyLink™ Program, which are in good condition and reflect favourably upon the Program. Upon any approved EnergyLink™ Program marketing or promotional materials becoming faded, cracked, torn, outdated, invalid or otherwise compromised in any manner, the Participant shall immediately discontinue use of such materials and, provided it has the required approval of Enbridge, replace at its sole cost and expense any such materials with new materials in good condition.

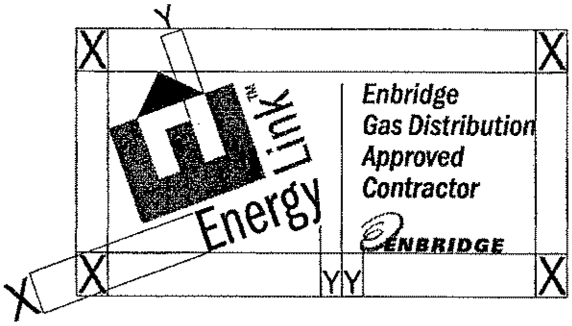
2. For greater certainty and without limiting the generality of the foregoing, under no circumstances whatsoever, shall the Participant:
   (a) reproduce, copy, import or use any trademarks or logos of Enbridge in any of its marketing or promotional materials and/or marketing events without the express prior written consent of Enbridge;
   (b) purport to authorize the use of any trademarks or logos of Enbridge by any sub-contractor of the Participant or by any other party; or

(c) use any trademarks or logos of Enbridge in a manner that would mis-represent or mis-communicate the relationship between the Participant and the EnergyLink™ Program. Any use of an Enbridge trademark or logo with out the concurrent use of the Participant's own trademarks and/or logos in a larger font or presentation size is strictly prohibited. Specifically, with respect to approved vehicle decals, the Participant is not permitted to affix EnergyLink™ Program promotional materials to unmarked vehicles or to vehicles with Participant branding or markings which are less prominent than those relating to the EnergyLink™ Program.

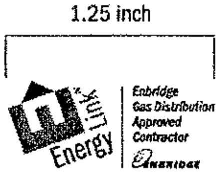
3. The Participant shall, at its own expense, remove all EnergyLink™ Program marketing and promotional materials from any
   (a) vehicle(s) that have been sold or decommissioned by the Participant.;
   (b) premises that are no longer used by the Participant in connection with an HVAC business.

   In addition, the Participant shall promptly remove or destroy any materials that the Participant is no longer authorized to use in connection with the EnergyLink™ Program.

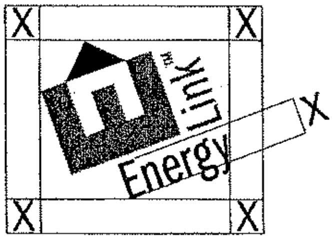
Trademark Guidelines



Protected Area
A minimum amount of clear space must surround the logo, separating it from headlines, text, other imagery or the outside edge of the item on which it appears. The protected area is equal to the cap height of the letter "E" in "Energy". Do not rotate the logo.



Smallest-size Logo
Do not use the Enbridge Gas Distribution Approved EnergyLink™ Contractor logo smaller than the size shown at the left. Do not rotate the logo.



Protected Area
A minimum amount of clear space must surround the logo, separating it from headlines, text, other imagery or the outside edge of the item on which it appears. The protected area is equal to the cap height of the letter "E" in "Energy". Do not rotate the logo.

Smallest-size Logo
Do not use the EnergyLink™ logo smaller than the size shown at the left. Do not rotate the logo.

Trademark Colours

Colour Logo
Enbridge Red
C0 M91 Y76 K6
In lieu of Enbridge Red,
use PANTONE® 186

Enbridge Yellow
C0 M29 Y91 K0 coated
C0 M18 Y83 K0 uncoated
In lieu of Enbridge Yellow,
use PANTONE® 1235 coated
or PANTONE® 122 uncoated

"Link™"
C0 M8 Y21 K32
or PANTONE® 7530

"Energy"
100% solid black

Greyscale Logo
The "E" symbol and "Link™" should be reproduced at 40% black. The triangle and "Energy" should be reproduced at 100% black. Do not rotate the logo.

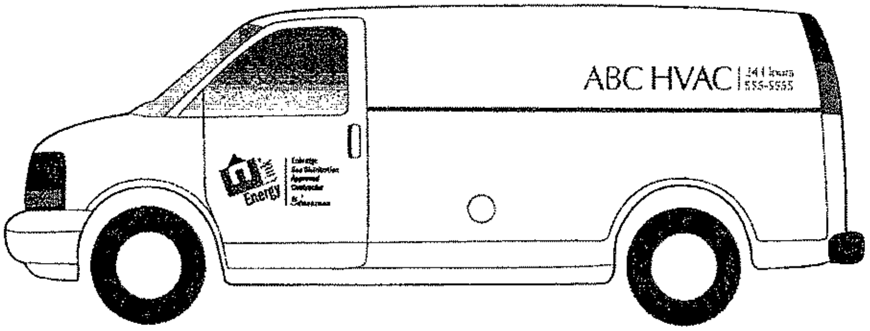
Solid Black Logo
This logo can be used on white or light coloured backgrounds. Do not rotate the logo.

Vehicle Decal

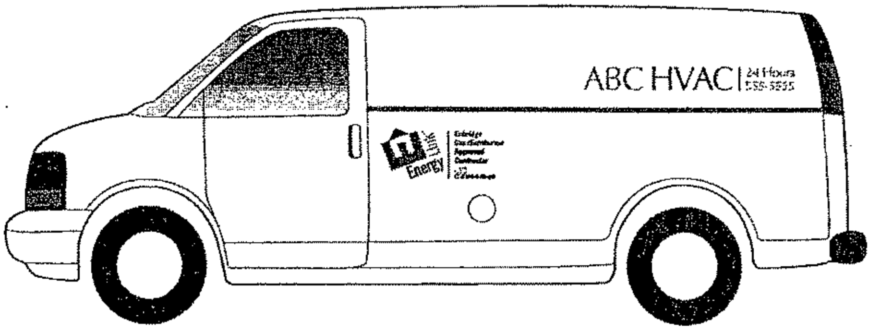
Energy Link™

Enbridge
Gas Distribution
Approved
Contractor
ENBRIDGE

Official Vehicle Decal



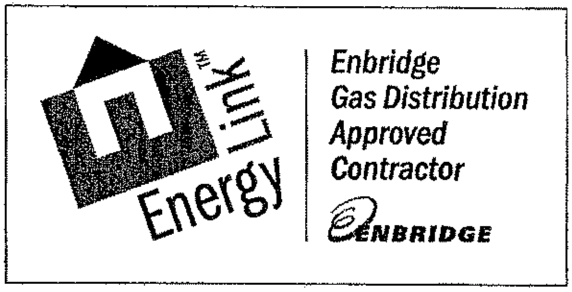
Application of Vehicle Decal - Option 1



Application of Vehicle Decal - Option 2

Note: Maximum two decals per vehicle allowed. The vehicle decal must appear on the same side as the Participant's trademarks and/or logos and must not be in a larger font or presentation size than the Participant's own trademark and/or logos.

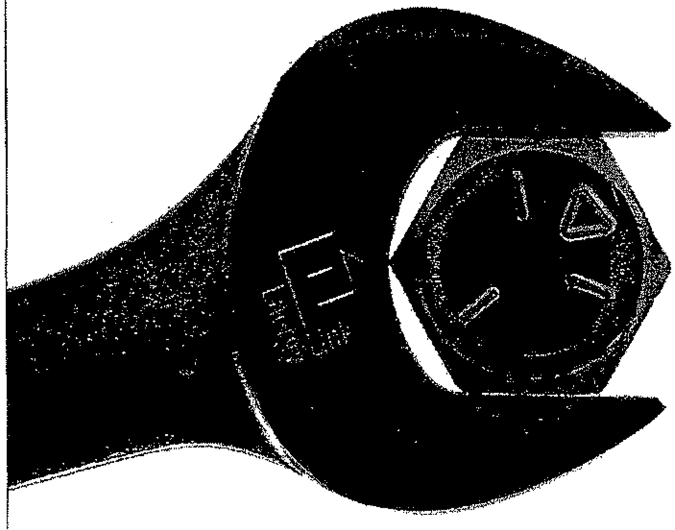
Window Decal



Official Logo Decal for Store Window

Ad Mat Option 1

How do you know if a contractor is qualified to install natural gas equipment?



All natural gas equipment and appliances should be installed by a qualified contractor. So how do you find one? The easiest way is to call a natural gas contractor who's a member of EnergyLink™. EnergyLink™ is a new program from Enbridge Gas Distribution that pre-screens contractors before they can become members. So call us because we are an approved EnergyLink™ natural gas contractor.

Contractor name goes here

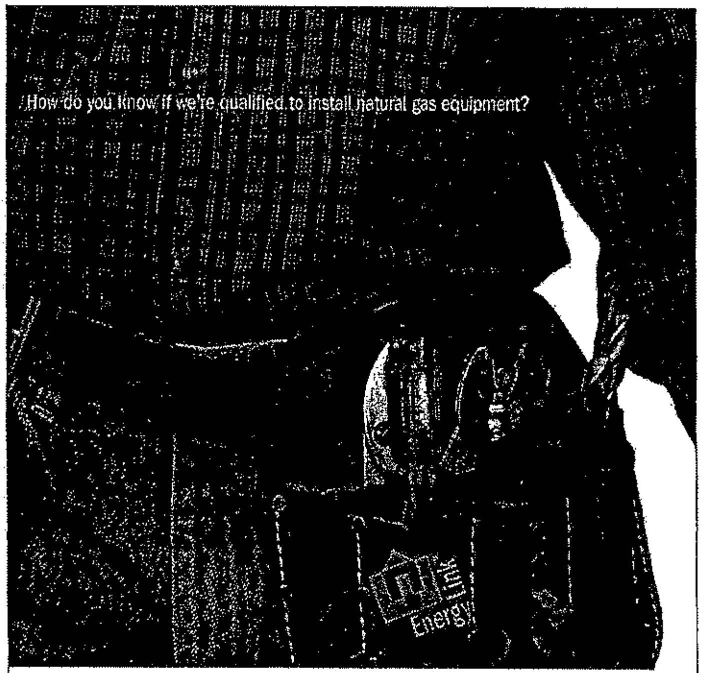
EnergyLink™

Enbridge
Gas Distribution
Approved
Contractor

Enbridge

EnergyLink™

Ad Mat Option 2



How do you know if we're qualified to install natural gas equipment?

All natural gas equipment and appliances should be installed by a qualified contractor. But how can you tell if a contractor is qualified? Well, if they're a natural gas contractor who's a member of EnergyLink™ they'll definitely be qualified to install and service natural gas equipment. EnergyLink™ is a new program from Enbridge Gas Distribution that pre-screens contractors before they can become members. So call us because we are an approved EnergyLink™ natural gas contractor.

Contractor name goes here

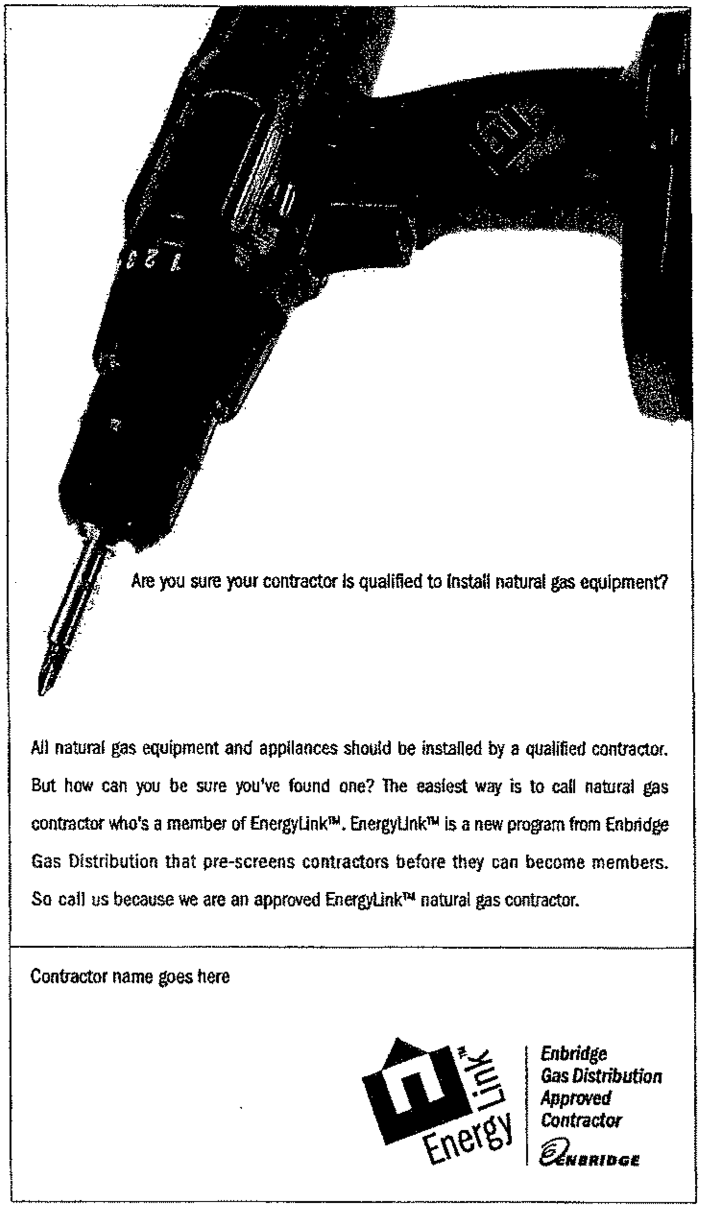
Energy Link™

Enbridge
Gas Distribution
Approved
Contractor

ENBRIDGE

Energy Link™

Ad Mat Option 3



Are you sure your contractor is qualified to install natural gas equipment?

All natural gas equipment and appliances should be installed by a qualified contractor. But how can you be sure you've found one? The easiest way is to call natural gas contractor who's a member of EnergyLink™. EnergyLink™ is a new program from Enbridge Gas Distribution that pre-screens contractors before they can become members. So call us because we are an approved EnergyLink™ natural gas contractor.

Contractor name goes here

Energy Link™

Enbridge
Gas Distribution
Approved
Contractor

ENBRIDGE

Energy Link™

Yellow Pages Ad Mats

For natural gas furnaces. You need a qualified contractor like us.

Your Company
name and
contact numbers
go here

Energy Link™
*Enbridge
Gas Distribution
Approved
Contractor*
Enbridge

For natural gas water heaters. You need a qualified contractor like us.

Your Company
name and
contact numbers
go here

Energy Link™
*Enbridge
Gas Distribution
Approved
Contractor*
Enbridge

ABC Contractors
Enbridge Gas Distribution Approved EnergyLink™ Contractor
Air Conditioning · Heating · Refrigeration
123 Any St., Anytown ———————— 416-555-5555

Yellow Pages Listing

For natural gas appliances. You need a qualified contractor like us.

Your Company
name and
contact numbers
go here

Energy Link™
*Enbridge
Gas Distribution
Approved
Contractor*
Enbridge

Energy Link™

Yellow Pages Ad Mats (with Enbridge logo)

For natural gas furnaces. You need a qualified contractor like us.

Your Company
name and
contact numbers
go here

Enbridge
Gas Distribution
Approved
Contractor

For natural gas water heaters. You need a qualified contractor like us.

Your Company
name and
contact numbers
go here

Enbridge
Gas Distribution
Approved
Contractor

ABC Contractors
Enbridge Gas Distribution Approved EnergyLink™ Contractor
Air Conditioning · Heating · Refrigeration
123 Any St., Anytown ———————— 416-555-5555

Yellow Pages Listing

For natural gas appliances. You need a qualified contractor like us.

Your Company
name and
contact numbers
go here

Enbridge
Gas Distribution
Approved
Contractor

EnergyLink™ Program Contacts

Sales Channel Consultant in your area:

METRO TORONTO

John Chitussi
416-495-5324
1-877-766-6696, ext. 5324
john.chitussi@enbridge.com

Darren Keates
905-436-7013
1-800-265-6164, ext. 7013
darren.keates@enbridge.com

Barry Lavender
416-495-5807
1-877-766-6696, ext. 5807
barry.lavender@enbridge.com

YORK REGION

Murray Wilson
905-887-4005, ext. 227
1-800-588-1914, ext. 227
murray.wilson@enbridge.com

GEORGIAN BAY

Dorothy Stewart
705-739-5227
1-800-461-4480, ext. 5227
dorothy.stewart@enbridge.com

DURHAM REGION

Darren Keates
905-436-7013
1-800-265-6164, ext. 7013
darren.keates@enbridge.com

Neil Saunders
905-436-7017
1-800-265-6164, ext. 7017
neil.saunders@enbridge.com

KAWARTHA LAKES/PETERBOROUGH

Don Armitage
705-749-5200, ext. 5236
1-888-899-9894, ext. 5236
don.armitage@enbridge.com

PEEL REGION/DUFFERIN

Valerie Kindree
905-458-2141
1-866-820-6215, ext. 2141
valerieann.kindree@enbridge.com

NIAGARA AREA

Linda Wilkinson
905-984-4923
1-800-461-0998, ext. 4923
linda.wilkinson@enbridge.com

OTTAWA AREA

Natalie Armstrong
613-747-4078
1-800-267-3616, ext. 4078
natalie.armstrong@enbridge.com

Leah Stiles
613-748-6703
1-800-267-3616, ext. 6703
leah.stiles@enbridge.com

EnergyLink™

ENBRIDGE

EnergyLink™ Vehicle Fax-in Form*

Company: North American General
Fax Number: 905-790-6249
Attention: Mr. Theo Sanders
Phone: 905-790-3674
Address: 21 Melanie Drive
Brampton, Ontario

EnergyLink™ Participant Name: ______________________
Phone: ______________________
Fax: ______________________
Email: ______________________
Date: ______________________

Completely fill in vehicle(s) information below:

Company Legal Name	Company Trade Name	Vehicle License Plate	Vehicle Registration Number	Number of Decals per Vehicle (max. 2 decals/vehicle)

*All the above vehicles are owned by the EnergyLink™ Program Participant. The EnergyLink™ Program Participant agrees that they will only use the vehicle decals with accordance with the EnergyLink™ Participant Program Agreement and Enbridge Trademark Usage Guidelines. Any use of an Enbridge trademark or logo without the concurrent use of the Participant's own trademarks and/or logos in a larger font or presentation size is strictly prohibited. The Participant is not permitted to affix EnergyLink™ Program promotional materials to unmarked vehicles or to vehicles with Participant branding or markings which are less prominent than those relating to the EnergyLink™ Program. The EnergyLink™ Program promotional decals must appear on the same side as the Participant branding or markings.

____
[EnergyLink™ Participant Signature]

Title: ______________________

EnergyLink™

EnergyLink™ Program

What does this Package Contain?

- Invitation to attend an EnergyLink™ Program CONTRACTOR PARTICIPANT SESSION
- EnergyLink™ Program MEMBERSHIP CRITERIA
- EnergyLink™ Program APPLICATION and MUNICIPALITIES selection list
- EnergyLink™ Program AGREEMENT – Retain for your review
- EnergyLink™ Brochure

Submitting the EnergyLink™ Application

Step 1. Clearly Print and fill in the APPLICATION FORM and include copies of all documents:

a) Minimum $2 million Auto Insurance
b) Minimum $5 million General Liability Insurance
c) WSIB certificate or Letter of Exemption
d) TSSA Company Registration
e) Customer Dispute Resolution Process (attach current documented process or outline your current policy on Page 4 – Customer Dispute Resolution).

Step 2. Submit SIGNED APPLICATION to:

Enbridge Gas Distribution Inc.
EnergyLink™ Program
1350 Thornton Road South
Oshawa, ON L1J 8C4
Attention: Mrs. Anne Heffernan
NO LATER THAN FRIDAY, OCTOBER 27, 2006

Step 3. Enbridge Gas Distribution is targeting to commence notification to Applicants the week of November 6, 2006

Submitting the EnergyLink™ Agreement

Step 4. **Upon Application Acceptance**, Enbridge Gas Distribution will forward two (2) executable copies of the EnergyLink™ Program Agreement for signature and we will require the Liability Insurance document naming Enbridge Gas Distribution Inc. as an additional insured.

Upon Final Acceptance, Enbridge Gas Distribution will provide you with ID's, Password and material to access the EnergyLink™ Referral System.

EnergyLink™ Program Membership Criteria

1. Minimum $2 million Auto Insurance
2. Minimum $5 million general liability insurance (and have no exclusions on working with Natural Gas). If accepted to the Program you will be asked to submit a document naming Enbridge Gas Distribution Inc. as an additional insured
3. TSSA Company Registration
4. Proof of WSIB or Letter of Exemption
5. Sound Financial Health
6. Provide Documented Customer Dispute Resolution process consistent with the terms of the Program Agreement
7. Must be a Full Service Provider (procure, install, repair and service) HVAC equipment
8. Must provide Free Quotes
9. Must have demonstrated participation in Enbridge Gas Distribution add load growth/DSM programs as measured by historical performance for rebate/incentive programs or activity in residential conversion/expansion programs
10. Must be able to receive emails
11. Must be able to access worldwide web using Microsoft Internal Explorer or Netscape
12. Must agree to contact the customer within 24 hours of receiving a referral and update the Referral status in the Referral Portal
13. Must agree to updating referrals in the Referral Portal with equipment details when won or with a closed status when not won
14. Must agree to maintain a high customer satisfaction level as assessed through Enbridge Gas Distribution's customer complaint and customer satisfaction process
15. Must agree to maintain items 1–14 for continued membership
16. Must sign the EnergyLink™ Program Agreement

EnergyLink™

HVAC Referral Program

APPLICATION FORM

NOTE: THIS FORM MUST BE COMPLETED IN FULL TO RECEIVE DUE CONSIDERATION.

Contractor Information (for Enbridge Gas Distribution Use Only)

Legal Name: ______________________________

Operating Name (if different from above): ______________________________

Business Address: ______________________________

City: ____________________ Province: ____________ Postal Code: __________

Full Mailing Address (if different from above): ______________________________

City: ____________________ Province: ____________ Postal Code: __________

Principal/Owner Name: ____________________ Phone #: __________

Contact Name (if other than Principal): ____________________ Phone #: __________

EnergyLink™ EMAIL ADDRESS: This is the email address that Enbridge Gas Distribution will use to send referrals to and should rarely, if ever, change. This address will not be provided to customers. It is an EnergyLink™ Program requirement that your Company have a computer platform with Windows PC or Mac and will need to be running either an Internet Explorer or Netscape browser.

Email Address: ______________________________

EnergyLink™ Administrator Name: ____________________ Phone #: __________

Email Address: ______________________________

Contractor Information (This will be displayed to customers)

Company Name: ______________________________

Business Address: ______________________________

City: ____________________ Province: ____________ Postal Code: __________

Day Phone #: ____________ Evening Phone #: ____________ Fax #: __________

Company Web Site: ______________________________

Contractor Marketing Message (maximum 255 characters): Suggestion for message area is, "years in business, service area (e.g. Serving GTA), show room features, specialties, brands, hours of operation, emergency service etc.

Copy and Content Approval Required by Enbridge Gas Distribution.

(Please Print) ______________________________

____

Insurance & Certificate Requirements (copies of documents 1, 2, 3 & 4 must be included)

1. **Auto Liability:**

   Amount: ____________ Policy #: ____________ Expiry Date: ____________

   Policy Holder: ____________ Carrier: ____________

2. **Comprehensive General Liability:** (If accepted to the Program, Enbridge Gas Distribution must be named as an additional insured under your Comprehensive General Liability Policy)

   Amount: ____________ Policy #: ____________ Expiry Date: ____________

   Policy Holder: ____________ Carrier: ____________

3. **TSSA Member Registration #:**____________ Expiry Date: ____________

4. **WSIB** Certificate of Clearance or Letter of Exemption: ____________ Expiry Date: ____________

Contractor Referral Municipalities

Please check off the specific municipalities and underlying communities you serve and are able to receive and process referrals on the attached listing (see page 6).

HVAC Gas Referral Products for EnergyLink™ Launch

Customers will be selecting from the following list of product categories. Please indicate the products you are able to fully service and receive and process EnergyLink™ Program Referrals.

Residential: ☐ Air Conditioning ☐ Boilers ☐ Fireplaces ☐ Furnaces
☐ Gas Appliance Installations ☐ In Floor Radiant ☐ Water Heaters

Commercial: ☐ Space Heating ☐ Water Heating ☐ Cooling

Products For Potential Future EnergyLink™ Programs: Enbridge Gas Distribution is also considering adding the following natural gas product categories from which customers can select. Please indicate the products you would be able to receive referrals for should Enbridge Gas Distribution choose to offer these at launch or in the future:

☐ Barbecues ☐ Campfires ☐ Dryers ☐ Garage Heater
☐ Generator ☐ Lamps ☐ Patio Heaters ☐ Pool Heaters
☐ Ranges ☐ Rental Water Heaters ☐ Tankless Water Heaters

Indoor Air Quality Products: ☐ Humidifiers ☐ Electronic Air Cleaners ☐ HEPA Filters ☐ Other ____________

OTHER product categories you would like to see included in the EnergyLink™ Program? ____________

Customer Dispute Resolution Process

Please describe (or attach a copy as an appendix to this document) your current Customer Dispute Resolution Process:

____

____

AUTHORIZATION

COMPANY NAME: ______________________________

Signature: Name and Title of Signing Officer: Date:

The above named hereby confirms the accuracy of information provided in this application.

COMMENTS

For EnergyLink™ Program Use Only

How to learn more.
If you are interested in becoming an EnergyLink™ approved natural gas contractor or retailer, be sure to fill out the forms enclosed and send them to:

Enbridge Gas Distribution Inc.
EnergyLink™ Program,
1350 Thornton Road South,
Oshawa, ON L1J 8C4
Attn: Anne Heffernan

Energy Link™

Don't delay for your opportunity to participate in this innovative new program from Enbridge Gas Distribution. EnergyLink™ can link you to customers who want to take advantage of all the benefits of natural gas. Become the expert they rely on. Become our customers' trusted EnergyLink™ contractor or retailer.

ENBRIDGE
Approved EnergyLink™ Contractor

ENBRIDGE

Would you
like to
be linked
to new
customers?

Introducing EnergyLink,™ your link to new customers.

EnergyLink™ is a new program from Enbridge Gas Distribution that links our customers to pre-screened natural gas contractors and retailers in their area.

Your link to more natural gas customers.

The EnergyLink™ Program will connect Enbridge Gas Distribution customers with contractors and retailers in their area who have been pre-screened by Enbridge. As a member of the EnergyLink™ Program, you can automatically receive referrals from Enbridge when customers in your service area access the EnergyLink™ website or phone line. Not only will this program give our customers access to a wide range of natural gas services and products, it will become another option for customers who want reliable, quality contractors or retailers.

Your link to more sales tools.

Members of the EnergyLink™ Program can access resources such as sales campaigns, programs, tools, and training developed by Enbridge specifically for natural gas contractors and retailers.

Your link to more advertising.

EnergyLink™ contractors and retailers will also be entitled to use advertising and branding materials designed to promote the EnergyLink™ Program. As well as the Enbridge EnergyLink™ logo graphics, approved contractors and retailers can have access to advertising and promotional materials (such as vehicle signage) to let potential customers know they are participants in the EnergyLink™ Program.

Your link to more business.

Being a member of the EnergyLink™ Program can help grow your business in more ways than one. When natural gas customers use EnergyLink,™ they will not only gain access to pre-screened contractors and retailers, they will also learn about energy conservation and the savings they can enjoy from the efficient use of energy. When they decide to upgrade their old furnaces and appliances, they can rely on EnergyLink™ contractors or retailers to help them make wise, informed choices. As an approved EnergyLink™ contractor or retailer, you can benefit from this increased customer interest in the advantages of natural gas and new high-efficiency natural gas products.

ENBRIDGE

Metro Toronto

☐ East York
☐ Etobicoke
☐ North York
☐ Scarborough
☐ Toronto

☐ All The Above

Peel/Dufferin

☐ Alton
☐ Bolton
☐ Brampton
☐ Caledon
☐ Caledon East
☐ Cheltenham
☐ Colgan
☐ Denfield
☐ Dundalk
☐ Erin
☐ Georgetown
☐ Grand Valley
☐ Hillsburgh
☐ Inglewood
☐ Laurel
☐ Lisle
☐ Mississauga
☐ Norval
☐ Orton
☐ Orangeville
☐ Palgrave
☐ Proton Station
☐ Shelburne
☐ Terra Cotta

☐ All The Above

York

☐ Aurora
☐ Baldwin
☐ Beaverton
☐ Cedar Valley
☐ Concord
☐ East Gwillimbury
☐ Goodwood
☐ Gormley
☐ Holland Landing
☐ Jackson's Point
☐ Keswick
☐ Kettleby
☐ King City
☐ Kleinburg
☐ Maple
☐ Markham
☐ Mount Albert
☐ Newmarket
☐ Nobleton
☐ Pefferlaw
☐ Pine Grove
☐ Queensville
☐ Richmond Hill
☐ River Drive Park
☐ Roches Point
☐ Schomberg
☐ Sharon
☐ Stouffville
☐ Sutton West
☐ Thornhill
☐ Vaughan
☐ Willow Beach
☐ Woodbridge

☐ All The Above

Kawartha/Peterborough

☐ Bailieboro
☐ Bethany
☐ Bewdley
☐ Bridgenorth
☐ Brighton
☐ Cameron
☐ Campbellford
☐ Cavan
☐ Codrington
☐ Douro
☐ Ennismore
☐ Fraserville
☐ Hastings
☐ Havelock
☐ Janetville
☐ Keene
☐ Lakefield
☐ Lindsay
☐ Little Britain
☐ Millbrook
☐ Mount Pleasant
☐ Nestleton Station
☐ Norwood
☐ Omemee
☐ Peterborough
☐ Pontypool
☐ Sunderland
☐ Trent River
☐ Warkworth
☐ Warsaw
☐ Youngs Point

☐ All The Above

Durham

☐ Ajax
☐ Ashburn
☐ Blackstock
☐ Bowmanville
☐ Brooklin
☐ Brougham
☐ Caesarea
☐ Cannington
☐ Castleton
☐ Claremont
☐ Columbus
☐ Courtice
☐ Greenbank
☐ Greenwood
☐ Hampton
☐ Locust Hill
☐ Newcastle
☐ Newtonville
☐ Orono
☐ Oshawa
☐ Pickering
☐ Port Perry
☐ Prince Albert
☐ Seagrave
☐ Uxbridge
☐ Whitby

☐ All The Above

Simcoe

☐ Alliston
☐ Angus
☐ Barrie
☐ Baxter
☐ Beeton
☐ Bond Head
☐ Borden
☐ Bradford
☐ Churchill
☐ Coldwater
☐ Collingwood
☐ Cookstown
☐ Creemore
☐ Elmvale
☐ Everett
☐ Gilford
☐ Hillsdale
☐ Innisfil
☐ Lefroy
☐ Loretto
☐ Meaford
☐ Midhurst
☐ Midland
☐ Minesing
☐ Moonstone
☐ New Lowell
☐ Nottawa
☐ Orillia
☐ Oro
☐ Penetanguishene
☐ Perkinsfield
☐ Phelpston
☐ Port Mcnicoll
☐ Shanty Bay
☐ Stayner
☐ Thornton
☐ Tottenham
☐ Utopia
☐ Victoria Harbour
☐ Warminster
☐ Wasaga Beach
☐ Waubaushene

☐ All The Above

Niagara

☐ Beamsville
☐ Crystal Beach
☐ Fenwick
☐ Fonthill
☐ Fort Erie
☐ Grimsby
☐ Niagara Falls
☐ Niagara-On-The-Lake
☐ Port Colborne
☐ Ridgeville
☐ Stevensville
☐ St. Catharines
☐ Wainfleet
☐ Welland

☐ All The Above

Eastern Region

☐ Almonte
☐ Alexandria
☐ Arnprior
☐ Athens
☐ Beachburg
☐ Bourget
☐ Braeside
☐ Brockville
☐ Carleton Place
☐ Carp
☐ Casselman
☐ Chalk River
☐ Clarence Creek
☐ Cobden
☐ Cornwall
☐ Cumberland
☐ Deep River
☐ Elizabethtown
☐ Embrun
☐ Glen Robertson
☐ Gloucester
☐ Greely
☐ Green Valley
☐ Haley Station
☐ Hammond
☐ Hawkesbury
☐ Kanata
☐ Kars
☐ Kemptville
☐ Lancaster
☐ Limoges
☐ L'Orignal
☐ Lyn
☐ Manotick
☐ Merrickville
☐ Metcalfe
☐ Munster
☐ Navan
☐ Nepean
☐ North Gower
☐ North Lancaster
☐ Osgoode
☐ Ottawa
☐ Pakenham
☐ Pembroke
☐ Perth
☐ Petawawa
☐ Renfrew
☐ Richmond
☐ Rockland
☐ Rockliffe
☐ Russell
☐ Smiths Falls
☐ South Lancaster
☐ St. Albert
☐ Stittsville
☐ Summerstown
☐ Toledo
☐ Vanier
☐ Vankleek Hill
☐ Vars
☐ Vernon
☐ Williamstown
☐ Woodlawn

☐ All The Above

Enbridge Gas Distribution Inc. – Franchise Communities
EnergyLink™ Program – October 2006

PROGRAM AGREEMENT

This Agreement is made ____________________, 200___ by and between Enbridge Gas Distribution Inc. (**"Enbridge"**), and ____ (**"Participant"**).

RECITALS

A. Enbridge administers a customer referral program called the **"EnergyLink™ Program"** designed to connect Enbridge customers (referred to herein as **"Customers"**) with pre-qualified contractors and retailers and thereby provide Customers with easy access to the natural gas energy solutions they seek. Contractors and retailers selected by Enbridge to participate in the EnergyLink™ Program may be referred to herein as **"EnergyLink™ Program Participants"**.

B. The Participant desires to be an EnergyLink™ Program Participant pursuant to the terms and conditions set forth in this Agreement and the Program Schedule(s) attached hereto.

AGREEMENT

NOW THEREFORE the parties agree as follows:

1. **Program Participant.** Enbridge hereby designates the Participant as an EnergyLink™ Program Participant and grants the Participant the non-exclusive right to identify itself as such to the public on and subject to the terms hereof.
2. **Participation Criteria.** In addition to complying with the requirements specifically set forth in this Agreement as an express condition of its selection for and continued participation in the EnergyLink™ Program, the Participant will at all times:
   (a) maintain an acceptable standard of customer practice;
   (b) comply with the EnergyLink™ specific Program Schedule(s) attached hereto (the **"Program Schedule(s)"**); and
   (c) furnish, install, repair and warrant the equipment described in the attached Program Schedule(s) (the **"Equipment"**) in accordance with the terms and conditions of this Agreement.
3. **Program Schedules.** The EnergyLink™ Program consists of distinct program components, all of which shall be described and be subject to the terms and conditions set out in specific Program Schedules. The Participant must be a party to at least one Program Schedule in order to be an EnergyLink™ Program Participant. Enbridge may, at any time, revise any or all of the Program Schedules in its sole discretion. Enbridge will provide EnergyLink™ Program Participants with notice of such revisions to Program Schedules as it deems appropriate in the circumstances, including but not limited to by means of postings on the EnergyLink™ website or general mailings.
4. **Term.** The term of this Agreement shall continue for the term(s) set out in the Program Schedule(s) executed by the parties. In the event that there is no valid Program Schedule in place between Enbridge and the Participant, this Agreement shall automatically terminate.
5. **Affirmative Obligations Regarding Program Participation.** During the term of this Agreement, the Participant:
   (a) warrants that (i) the Participant is not an employee of Enbridge or any of Enbridge's affiliates (as such term is defined in the *Business Corporations Act* (Ontario), referred to herein as **"Affiliates"**); and (ii) no partner, officer, director, or majority owner or shareholder of the Participant is an employee of Enbridge or any of Enbridge's Affiliates;
   (b) warrants that all information it has provided to Enbridge in its application to participate in the EnergyLink™ Program (or any component thereof), or in any updates to such information, is true and correct, and agrees to advise Enbridge of any changes to such information that may arise after the date hereof;

(c) consents to the obtaining from any credit agency or other entity such reference or other information as Enbridge may reasonably require at any time, and consents to the disclosure at any time of any information concerning the Participant to any such agency or entity;

(d) warrants that all subcontractors who perform work referred to the Participant under the EnergyLink™ Program shall at all times comply with the terms and conditions of this Agreement as if such subcontractors were the Participant hereunder, and upon request, will provide evidence of its subcontractors' compliance with the terms and conditions of this Agreement, including but not limited to insurance, *Technical Standards and Safety Act* (Ontario), *Workplace Safety and Insurance Act* (Ontario) and other requirements;

(e) will comply with all federal, provincial or municipal laws, regulations, codes and/or ordinances applicable to: (i) the Participant, its employees or subcontractors; or (ii) the Equipment, its sale, installation or servicing;

(f) will adhere at all times to Enbridge's program criteria, rules, safety guidelines and codes of conduct in dealing with Customers and in the performance of all work to it referred under the EnergyLink™ Program; and

(g) will conduct its business in a professional manner that will in no way compromise the standards of Enbridge or the EnergyLink™ Program.

The Participant acknowledges that any failure to comply with this Section 5 will constitute a breach of this Agreement.

6. **Customer Service Obligations.** The Participant will at all times maintain a high level of customer service and satisfaction during the term of this Agreement. Without limiting the generality of the foregoing, the Participant will:

(a) contact Customers within twenty-four (24) hours of its receipt of a referral;

(b) attend at the Customer's site (if requested) and provide a free initial written quote for all work referred to it under the EnergyLink™ Program;

(c) keep appointments or contact Customers in advance to reschedule;

(d) clean up the work area to each Customer's satisfaction after installation or service;

(e) prepare, install, adjust and service all Equipment according to manufacturer's specifications;

(f) in addition to (and not in place of) any applicable manufacturer's warranties, warrant to Customers that the Equipment and/or installation thereof provided by the Participant to Customers will be free from defects for a minimum of one (1) year from the date of installation;

(g) remedy any and all failures to conform to the warranty referred to in subparagraph 6(f) within seven (7) business days of notification by either Customer or Enbridge of such failure, or such other reasonable time period as may be agreed to by Customer in writing;

(h) at any time immediately correct any and all code or other violations relating to the Equipment, its installation or servicing;

(i) immediately take all necessary safety precautions and appropriate actions to remedy any unsafe condition related to the Equipment; and

(j) not mislead Customers or engage in any unfair or deceptive marketing or trade practice.

The Participant acknowledges that any failure to comply with this Section 6 will constitute a breach of this Agreement.

7. **Customer Satisfaction.** The Participant acknowledges and agrees that Enbridge may at any time inspect installations and/or contact Customers (in each case, with the Customer's consent), for the purpose of assessing the Participant's work referred under the EnergyLink™ Program.

8. **Customer Information.** The Participant shall hold all Customer information it receives by virtue of its participation in the EnergyLink™ Program, including but not limited to Customers' name, address, contact information, payment information, preferences, needs or requirements (the **"Customer Information"**), in strict confidence and shall not use the Customer Information for any purpose which has not been expressly consented to by the applicable Customer. In addition, the Participant agrees that it shall comply with all laws applicable to the personal information of Customers, including but not limited to the *Personal Information Protection and Electronic Documents Act*.

9. **Advertising and Use of Trademarks.** Enbridge may, in its sole discretion, provide branding, advertising, marketing material, program informational material, manuals, training material, software and other documents and items related to the EnergyLink™ Program (the **"Enbridge Materials"**) directly to the Participant. All Enbridge Materials shall remain the sole and exclusive property of Enbridge. The Participant will ensure that its use of the Enbridge Materials strictly complies with Enbridge's trademark usage guidelines in effect from time to time. Enbridge may at any time require that the Participant stop using, or alter its usage, of all or any part of the Enbridge Materials which have been provided to the Participant. In such case, the Participant shall immediately comply with any requirements communicated to it by Enbridge. Upon termination of this Agreement for any reason, the Participant will immediately:

   (a) cease use of all Enbridge Materials;

   (b) discontinue all use, whether oral or written, of the name and trademarks provided;

   (c) make no further representation to any Customer or prospective Customer to the effect that the Participant is an EnergyLink™ Program Participant or in any way associated with, connected with, or linked to the EnergyLink™ Program or Enbridge;

   (d) take all action required to remove any such references from all existing advertising or directory listings;

   (e) deliver to Enbridge any Enbridge Materials in the Participant's possession; and

   (f) deliver to Enbridge a certificate of an officer of the Participant certifying the Participant's compliance with this Section 9.

   The Participant acknowledges that any failure to comply with this Section 9 will constitute a breach of this Agreement and trademark infringement.

10. **Insurance.** The Participant shall at its own expense maintain and keep in full force and effect during the term hereof and for a period of two (2) years following the expiry or termination of this Agreement:

   (a) commercial general liability insurance having a minimum inclusive coverage limit, including personal injury and property damage, of at least Five Million Dollars ($5,000,000). Enbridge shall be added as an additional insured in the insurance policy. The insurance policy shall: (i) cover contractual liability, completed operations liability and owners'/contractors' protective liability; (ii) not exclude any activities that the Participant is likely to perform in connection with the EnergyLink™ Program, including work with live gas; and (iii) contain a cross liability clause;

   (b) automobile liability insurance on all vehicles used in connection with this Agreement and such insurance shall have a limit of at least Two Million Dollars ($2,000,000) in respect of bodily injury (including passenger hazard) and property damage inclusive of any one accident; and

   (c) non-owned automobile liability insurance and such insurance shall have a limit of at least Two Million Dollars ($2,000,000) in respect of bodily injury (including passenger hazard) and property damage, inclusive in any one accident.

   The Participant shall forthwith after entering into this Agreement, and from time to time thereafter at the request of Enbridge, furnish to Enbridge a memorandum of insurance or an insurance certificate setting out the terms and conditions of each policy of insurance (all such policies of insurance referred to as the **"Insurance Policies"**) maintained by the Participant in order to satisfy the requirements of this Section. The Insurance Policies shall be arranged with insurers acceptable to Enbridge, acting reasonably, and shall contain such terms and conditions as are reasonably acceptable to Enbridge. The Participant shall not cancel, terminate or materially alter the terms of any of the Insurance Policies without giving prior notice in writing to Enbridge. The Participant shall cause or arrange for any of its insurers under any one or more of the Insurance Policies to oblige itself contractually in writing to Enbridge to provide fifteen (15) days prior notice in writing before cancelling, terminating or materially altering the Insurance Policies under which it is an insurer.

11. **Compliance with Laws.** The Participant agrees to comply with the *Occupational Health and Safety Act* (Ontario), the *Technical Standards and Safety Act* (Ontario) and the *Workplace Safety and Insurance Act* (Ontario) and all other prevailing federal, provincial and municipal laws and regulations or any other laws or regulations in force which are applicable to the Participant, its employees or subcontractors and the work referred under the EnergyLink™ Program, and the Participant shall familiarize itself and procure all required permits and licenses and pay all charges and fees necessary or incidental to the due and lawful performance of all work referred under the EnergyLink™ Program. The Participant shall from time to

time, upon request by Enbridge, provide Enbridge with evidence of such compliance, and in particular, evidence from the Workplace Safety and Insurance Board, or its successor if any, that the Participant and its subcontractors are in compliance with and have paid all assessments and other amounts owing pursuant to the *Workplace Safety and Insurance Act* (Ontario).

12. **Indemnification.** The Participant agrees to indemnify, defend and hold harmless Enbridge and Enbridge's directors, officers, employees and agents (**"Indemnitees"**) from any and all claims, demands, losses, harm, costs, liabilities, damages and expenses of every nature and kind whatsoever (including without limitation legal fees and disbursements, investigation expenses, and adjuster's fees and expenses), resulting from or in any manner arising out of or in connection with or referable to:

    (a) any act, omission, default or negligence of the Participant, or its employees, representatives, subcontractors or agents;

    (b) any breach of this Agreement or any actual or alleged breach of an agreement between the Participant and a Customer; or

    (c) any defective, deficient or non-complying product, services or other items furnished by the Participant.

    Enbridge may elect to have its representatives accompany the Participant's representatives to any settlement negotiations or proceedings relating to any claim governed by this Section 12. Any release forms used in settling any claim governed by this Section 12 shall be subject to Enbridge's approval and shall be made in favour of both the Program Participant and Enbridge.

13. **Independence of Parties.** Neither party will be entitled to attempt to create or assume any obligation, express or implied on behalf of the other. This Agreement will not be interpreted or construed to create an association, subcontract, joint venture, partnership or franchise relationship between the parties or to impose any partnership or franchise obligation or liability upon either party. Under no circumstances will the Participant or any of its employees, representatives or agents:

    (a) represent themselves as employees, representatives, subcontractors or agents of Enbridge;

    (b) refer to Enbridge in any contract between the Participant and a Customer relating to work referred to the Participant under the EnergyLink™ Program; or

    (c) refer to Enbridge or use any Enbridge trademarks in any advertising or promotional materials, without having first received Enbridge's express written consent.

14. **Non-Exclusive Agreement.** The Participant understands and acknowledges that no promises or representations whatsoever have been made as to the actual or potential number of Customers that may be referred by Enbridge to the Participant under the EnergyLink™ Program. The Participant further acknowledges that in no event shall Enbridge be responsible for costs or expenses the Participant may incur, if any, to participate in the EnergyLink™ Program. This Agreement is non-exclusive in that Enbridge may refer Customers to persons or entities other than the Participant and the Participant may seek and accept referrals from persons or entities other than Enbridge.

15. **Termination of this Agreement.** Either party may terminate this Agreement, with or without cause, upon thirty (30) days written notice to the other. Further, Enbridge may terminate this Agreement immediately in the event the Participant breaches any provision of this Agreement. The obligations imposed under this Agreement that may be reasonably interpreted or construed as surviving the termination or expiration of this Agreement, including without limitation those obligations specified in Sections 5, 6, 7, 8, 9, 10, 12, 18, 20, 21 and 22, shall survive the termination or expiration of this Agreement.

16. **No Transfer/Assignment without Consent.** For the purposes of this Section, a **"Transfer"** means: (a) an assignment or other disposition of this Agreement in whole or in part (whether by operation of law or otherwise); (b) an assignment, sale or other disposition of any interest (whether in shares, partnership units or other interests) in the Participant which results in a change in the effective voting control of the Participant; or (c) a merger, amalgamation or other similar corporate reorganization involving the Participant. The Participant will not complete any Transfer without the prior written consent of Enbridge. Prior to granting its consent to a Transfer, Enbridge may require that the Participant (or its proposed successor) update, confirm, re-validate or re-issue all certificates, reports, documents or requirements set out in this Agreement. Any Transfer completed by the Participant without the prior written consent of Enbridge will result in the automatic termination of this Agreement. In such case, a party must reapply if it wishes to be an EnergyLink™ Program Participant. Subject to the foregoing restriction on Transfers by the Participant, this Agreement will be fully binding upon, enure to the benefit of, and be enforceable by the parties and their respective successors and assigns.

17. **Notices.** Unless otherwise set out in this Agreement, any notice or other communication given by either party to the other party under this Agreement will be in writing and will be deemed to have been duly given when: (a) delivered by hand; (b) received by the recipient if sent by nationally recognized overnight delivery service or by letter mail (with receipt requested); or (c) received by the recipient by any other reasonable method to extent the other party has evidence of the receiving party's receipt thereof. Either party may from time to time change its address by giving the other party notice of the change in accordance with this Section.

18. **Remedy.** The Participant acknowledges that any breach by Program Participant of this Agreement may cause irreparable injury to Enbridge. Accordingly, in the event of such breach or an impending breach, Enbridge will be entitled to obtain temporary restraining orders, injunctions and other equitable relief from a court in addition to and not in lieu of the right to seek damages and any other right or remedy afforded to Enbridge by law or otherwise.

19. **Waiver.** The failure by Enbridge to insist upon strict enforcement of any of the terms and conditions of this Agreement shall not constitute a waiver of such right.

20. **Governing Law.** This Agreement will be interpreted, constructed and enforced in all respects in accordance with the laws of the Province of Ontario and the federal laws of Canada applicable therein. The Participant will not commence or prosecute any action, claim, suit or other proceeding under or related to this Agreement other than in the Province of Ontario and hereby consents to the jurisdiction and venue of the courts in the Province of Ontario.

21. **Invalidity/Unenforceability.** If any part of any provision of this Agreement is invalid or unenforceable, the provision will be ineffective only to the extent of such invalidity or unenforceability without in any way affecting the remaining parts of the provision or this Agreement.

22. **Entire Understanding.** This writing represents the entire agreement and understanding of the parties with respect to the subject matter hereof and supersedes any and all previous agreements of whatever nature between the parties with respect to the subject matter. Unless otherwise set out herein, this Agreement may not be altered or amended without the written agreement of both parties.

23. **Counterparts.** This Agreement may be signed in one or more original, electronic or facsimile counterparts, each of which, when executed and delivered, shall be deemed to be an original, and all of which, when taken together, shall constitute but one and the same Agreement.

IN WITNESS WHEREOF the parties have entered into this Agreement effective as of the date first above written.

ENBRIDGE GAS DISTRIBUTION INC.

Per: ______________________________
Name:
Title:

Per: ______________________________
Name:
Title:

PROGRAM PARTICIPANT:

____
[Write Complete Legal Name of Participant Above]

Per: ______________________________
Name:
Title:

Per: ______________________________
Name:
Title:
I/we have authority to bind the Participant.

SCHEDULE A – HVAC REFERRAL PROGRAM

This Program Schedule to the EnergyLink™ Program Agreement between Enbridge Gas Distribution Inc. (**"Enbridge"**) and ____ (**"Participant"**) is entered into ____ *[Date].*

1. **HVAC Referral Program.** As part of the EnergyLink™ Program, the HVAC Referral Program will connect Customers seeking the purchase and installation of or service for furnaces, boilers/hydronics, water heaters, fireplaces, air conditioning units, dryers, pool heaters, barbeques and other residential or commercial natural gas equipment and piping, with EnergyLink™ Program Participants. The terms and conditions of the HVAC Referral Program are set out in this Program Schedule. Enbridge reserves the right to amend the provisions of this Program Schedule at any time. Enbridge will provide EnergyLink™ Program Participants with such notice of revisions to this Program Schedule as it deems appropriate in the circumstances, including but not limited to by means of postings on the EnergyLink™ website or general mailings.
2. **Term.** This Program Schedule will terminate on ____________________, unless renewed for additional term(s) by Enbridge upon advance written notice to the Participant. As part of the renewal process, or at the request of Enbridge at any time, the Participant will update, confirm, re-validate or re-issue all certificates, reports, documents or requirements set out in this Agreement.
3. **Training.** The Participant agrees to attend computer training related to the EnergyLink™ Program and will keep confidential all passwords and content. The Participant and its employees will also attend and complete such additional training or orientation, from time to time, as may be required by Enbridge. All manuals, software and training materials provided to the Participant by Enbridge shall remain the property of Enbridge. In the event of termination, the Participant agrees to return all such items to Enbridge in accordance with the terms of this Agreement.
4. **Service and Program Obligations.** During the term of this Program Schedule, the Participant will:
   (a) operate a full service HVAC contracting business, capable of completing sales, installations, servicing, repairs and removals of Equipment;
   (b) contact Customers within twenty-four (24) hours of its receipt of a referral;
   (c) attend at the Customer's site (if requested) and provide a free initial written quote for all work referred to it under the EnergyLink™ Program;
   (d) ensure that all Participant property to which Enbridge Materials may be affixed (including vehicles or other property) shall be presentable and safe for their intended use;
   (e) participate in and actively support Enbridge's added load/DSM campaigns;
   (f) upon request, provide evidence of its, and its subcontractors', ongoing compliance with the terms of this Agreement, including but not limited to insurance, TSSA, WSIB and other requirements;
   (g) not use the EnergyLink™ Program or the EnergyLink™ Referral System (as defined below) in any manner intended to manipulate the number of referrals generated for the Participant; and
   (h) comply with such program criteria, rules, safety guidelines and codes of conduct relating to EnergyLink™ Program as Enbridge may specify from time to time.
5. **Reporting and Communications.** The Participant shall at all times maintain Internet service sufficient to meet its reporting and other obligations under this Agreement. The Participant shall check email and update the online EnergyLink™ referral system (the **"EnergyLink™ Referral System"**) each day, including weekends and holidays, in order to respond to Customer inquiries. The Participant shall promptly notify Enbridge in the event of lost passwords, erroneous information entered into the EnergyLink™ Referral System, suspected security breaches, or other software or reporting related concerns.

The Participant shall promptly provide Enbridge with such reports and updates as may be required from time to time, including:

(a) Updating the EnergyLink™ Referral System on the status of initial customer contacts and reporting the final status of the referral within twenty-four (24) hours;

(b) Providing information to Enbridge on natural gas equipment and DSM measures installed, including all natural gas up-sell opportunities closed; and

(c) Providing such other information as is requested by the EnergyLink™ Referral System.

The Participant acknowledges that Enbridge will be using the information entered into the EnergyLink™ Referral System to track and report on EnergyLink™ Program Participant performance, including close ratios, up-sell opportunities closed, Customer satisfaction levels, dispute resolution statistics and all other performance obligations identified in this Agreement.

The Participant will meet with Enbridge representatives on a regular basis, at the request of either party, to discuss its performance in the EnergyLink™ Program and to provide feedback to Enbridge on the EnergyLink™ Program.

6. **Participant Contact Information.** The Participant agrees to update, as necessary, their profile and contact information via the EnergyLink™ Referral System, including their mailing addresses, contact person(s), phone numbers, email address(es).

7. **Self-Suspension.** The Participant may at any time request that Enbridge cease providing it with referrals for a period of not less than two (2) weeks.

8. **Dispute Resolution.** The Participant shall at all times during the term of this Program Schedule have in place a written customer dispute resolution process consistent with the terms and conditions of this Agreement.

   In the event that Enbridge receives a complaint relating to Equipment installed or services performed by the Participant, the Participant shall contact the Customer within twenty-four (24) hours of notice of the complaint and use its best efforts to remedy the situation to the Customer's satisfaction within five (5) business days. The Participant will promptly repair, at no additional charge to the Customer, any Equipment installed or service performed that does not comply with the terms and conditions set forth in this Agreement. In the event that the Customer complaint remains unresolved after the Participant contacts Customer and/or attempts to repair the Equipment and/or service, the Participant shall promptly advise Enbridge. The Participant authorizes Enbridge to independently assess any Customer complaint (including by inspecting any installations and/or contacting the Customer) and make a final determination resolving the issue. The Participant agrees that any such determination by Enbridge will be final and binding upon the Participant.

   In the event that the Participant averages an escalated complaint rate of more than 10% for more than three (3) consecutive months, Enbridge reserves the right, in its sole direction, to suspend or terminate the Participant from the EnergyLink™ Program.

IN WITNESS WHEREOF the parties have entered into this Program Schedule effective as of the date first above written.

ENBRIDGE GAS DISTRIBUTION INC.

Per: ______________________________
Name:
Title:

Per: ______________________________
Name:
Title:

PROGRAM PARTICIPANT:

____
[Write Complete Legal Name of Participant Above]

Per: ______________________________
Name:
Title:

Per: ______________________________
Name:
Title:
I/we have authority to bind the Participant.

How to learn more.
If you are interested in becoming an EnergyLink™ approved natural gas contractor or retailer, be sure to fill out the forms enclosed and send them to:

Enbridge Gas Distribution Inc.
EnergyLink™ Program,
1350 Thornton Road South,
Oshawa, ON L1J 8C4
Attn: Anne Heffernan

EnergyLink™

Don't delay for your opportunity to participate in this innovative new program from Enbridge Gas Distribution. EnergyLink™ can link you to customers who want to take advantage of all the benefits of natural gas. Become the expert they rely on. Become our customers' trusted EnergyLink™ contractor or retailer.

ENBRIDGE

Approved EnergyLink™ Contractor

ENBRIDGE

Would you like to be linked to new customers?

Introducing EnergyLink,™ your link to new customers.

EnergyLink™ is a new program from Enbridge Gas Distribution that links our customers to pre-screened natural gas contractors and retailers in their area.

Your link to more natural gas customers.

The EnergyLink™ Program will connect Enbridge Gas Distribution customers with contractors and retailers in their area who have been pre-screened by Enbridge. As a member of the EnergyLink™ Program, you can automatically receive referrals from Enbridge when customers in your service area access the EnergyLink™ website or phone line. Not only will this program give our customers access to a wide range of natural gas services and products, it will become another option for customers who want reliable, quality contractors or retailers.

Your link to more sales tools.

Members of the EnergyLink™ Program can access resources such as sales campaigns, programs, tools, and training developed by Enbridge specifically for natural gas contractors and retailers.

Your link to more advertising.

EnergyLink™ contractors and retailers will also be entitled to use advertising and branding materials designed to promote the EnergyLink™ Program. As well as the Enbridge EnergyLink™ logo graphics, approved contractors and retailers can have access to advertising and promotional materials (such as vehicle signage) to let potential customers know they are participants in the EnergyLink™ Program.

Your link to more business.

Being a member of the EnergyLink™ Program can help grow your business in more ways than one. When natural gas customers use EnergyLink,™ they will not only gain access to pre-screened contractors and retailers, they will also learn about energy conservation and the savings they can enjoy from the efficient use of energy. When they decide to upgrade their old furnaces and appliances, they can rely on EnergyLink™ contractors or retailers to help them make wise, informed choices. As an approved EnergyLink™ contractor or retailer, you can benefit from this increased customer interest in the advantages of natural gas and new high-efficiency natural gas products.

ENBRIDGE

Metro Toronto

☐ East York
☐ Etobicoke
☐ North York
☐ Scarborough
☐ Toronto

☐ All The Above

Peel/Dufferin

☐ Alton
☐ Bolton
☐ Brampton
☐ Caledon
☐ Caledon East
☐ Cheltenham
☐ Colgan
☐ Denfield
☐ Dundalk
☐ Erin
☐ Georgetown
☐ Grand Valley
☐ Hillsburgh
☐ Inglewood
☐ Laurel
☐ Lisle
☐ Mississauga
☐ Norval
☐ Orton
☐ Orangeville
☐ Palgrave
☐ Proton Station
☐ Shelburne
☐ Terra Cotta

☐ All The Above

York

☐ Aurora
☐ Baldwin
☐ Beaverton
☐ Cedar Valley
☐ Concord
☐ East Gwillimbury
☐ Goodwood
☐ Gormley
☐ Holland Landing
☐ Jackson's Point
☐ Keswick
☐ Kettleby
☐ King City
☐ Kleinburg
☐ Maple
☐ Markham
☐ Mount Albert
☐ Newmarket
☐ Nobleton
☐ Pefferlaw
☐ Pine Grove
☐ Queensville
☐ Richmond Hill
☐ River Drive Park
☐ Roches Point
☐ Schomberg
☐ Sharon
☐ Stouffville
☐ Sutton West
☐ Thornhill
☐ Vaughan
☐ Willow Beach
☐ Woodbridge

☐ All The Above

Kawartha/Peterborough

☐ Bailieboro
☐ Bethany
☐ Bewdley
☐ Bridgenorth
☐ Brighton
☐ Cameron
☐ Campbellford
☐ Cavan
☐ Codrington
☐ Douro
☐ Ennismore
☐ Fraserville
☐ Hastings
☐ Havelock
☐ Janetville
☐ Keene
☐ Lakefield
☐ Lindsay
☐ Little Britain
☐ Millbrook
☐ Mount Pleasant
☐ Nestleton Station
☐ Norwood
☐ Omemee
☐ Peterborough
☐ Pontypool
☐ Sunderland
☐ Trent River
☐ Warkworth
☐ Warsaw
☐ Youngs Point

☐ All The Above

Durham

☐ Ajax
☐ Ashburn
☐ Blackstock
☐ Bowmanville
☐ Brooklin
☐ Brougham
☐ Caesarea
☐ Cannington
☐ Castleton
☐ Claremont
☐ Columbus
☐ Courtice
☐ Greenbank
☐ Greenwood
☐ Hampton
☐ Locust Hill
☐ Newcastle
☐ Newtonville
☐ Orono
☐ Oshawa
☐ Pickering
☐ Port Perry
☐ Prince Albert
☐ Seagrave
☐ Uxbridge
☐ Whitby

☐ All The Above

Simcoe

☐ Alliston
☐ Angus
☐ Barrie
☐ Baxter
☐ Beeton
☐ Bond Head
☐ Borden
☐ Bradford
☐ Churchill
☐ Coldwater
☐ Collingwood
☐ Cookstown
☐ Creemore
☐ Elmvale
☐ Everett
☐ Gilford
☐ Hillsdale
☐ Innisfil
☐ Lefroy
☐ Loretto
☐ Meaford
☐ Midhurst
☐ Midland
☐ Minesing
☐ Moonstone
☐ New Lowell
☐ Nottawa
☐ Orillia
☐ Oro
☐ Penetanguishene
☐ Perkinsfield
☐ Phelpston
☐ Port Mcnicoll
☐ Shanty Bay
☐ Stayner
☐ Thornton
☐ Tottenham
☐ Utopia
☐ Victoria Harbour
☐ Warminster
☐ Wasaga Beach
☐ Waubaushene

☐ All The Above

Niagara

☐ Beamsville
☐ Crystal Beach
☐ Fenwick
☐ Fonthill
☐ Fort Erie
☐ Grimsby
☐ Niagara Falls
☐ Niagara-On-The-Lake
☐ Port Colborne
☐ Ridgeville
☐ Stevensville
☐ St. Catharines
☐ Wainfleet
☐ Welland

☐ All The Above

Eastern Region

☐ Almonte
☐ Alexandria
☐ Arnprior
☐ Athens
☐ Beachburg
☐ Bourget
☐ Braeside
☐ Brockville
☐ Carleton Place
☐ Carp
☐ Casselman
☐ Chalk River
☐ Clarence Creek
☐ Cobden
☐ Cornwall
☐ Cumberland
☐ Deep River
☐ Elizabethtown
☐ Embrun
☐ Glen Robertson
☐ Gloucester
☐ Greely
☐ Green Valley
☐ Haley Station
☐ Hammond
☐ Hawkesbury
☐ Kanata
☐ Kars
☐ Kemptville
☐ Lancaster
☐ Limoges
☐ L'Orignal
☐ Lyn
☐ Manotick
☐ Merrickville
☐ Metcalfe
☐ Munster
☐ Navan
☐ Nepean
☐ North Gower
☐ North Lancaster
☐ Osgoode
☐ Ottawa
☐ Pakenham
☐ Pembroke
☐ Perth
☐ Petawawa
☐ Renfrew
☐ Richmond
☐ Rockland
☐ Rockliffe
☐ Russell
☐ Smiths Falls
☐ South Lancaster
☐ St. Albert
☐ Stittsville
☐ Summerstown
☐ Toledo
☐ Vanier
☐ Vankleek Hill
☐ Vars
☐ Vernon
☐ Williamstown
☐ Woodlawn

☐ All The Above

PROGRAM AGREEMENT

This Agreement is made ____________________, 200___ by and between Enbridge Gas Distribution Inc. (**"Enbridge"**), and ____ (**"Participant"**).

RECITALS

A. Enbridge administers a customer referral program called the **"EnergyLink™ Program"** designed to connect Enbridge customers (referred to herein as **"Customers"**) with pre-qualified contractors and retailers and thereby provide Customers with easy access to the natural gas energy solutions they seek. Contractors and retailers selected by Enbridge to participate in the EnergyLink™ Program may be referred to herein as **"EnergyLink™ Program Participants"**.

B. The Participant desires to be an EnergyLink™ Program Participant pursuant to the terms and conditions set forth in this Agreement and the Program Schedule(s) attached hereto.

AGREEMENT

NOW THEREFORE the parties agree as follows:

1. **Program Participant.** Enbridge hereby designates the Participant as an EnergyLink™ Program Participant and grants the Participant the non-exclusive right to identify itself as such to the public on and subject to the terms hereof.
2. **Participation Criteria.** In addition to complying with the requirements specifically set forth in this Agreement as an express condition of its selection for and continued participation in the EnergyLink™ Program, the Participant will at all times:
   (a) maintain an acceptable standard of customer practice;
   (b) comply with the EnergyLink™ specific Program Schedule(s) attached hereto (the **"Program Schedule(s)"**); and
   (c) furnish, install, repair and warrant the equipment described in the attached Program Schedule(s) (the **"Equipment"**) in accordance with the terms and conditions of this Agreement.
3. **Program Schedules.** The EnergyLink™ Program consists of distinct program components, all of which shall be described and be subject to the terms and conditions set out in specific Program Schedules. The Participant must be a party to at least one Program Schedule in order to be an EnergyLink™ Program Participant. Enbridge may, at any time, revise any or all of the Program Schedules in its sole discretion. Enbridge will provide EnergyLink™ Program Participants with notice of such revisions to Program Schedules as it deems appropriate in the circumstances, including but not limited to by means of postings on the EnergyLink™ website or general mailings.
4. **Term.** The term of this Agreement shall continue for the term(s) set out in the Program Schedule(s) executed by the parties. In the event that there is no valid Program Schedule in place between Enbridge and the Participant, this Agreement shall automatically terminate.
5. **Affirmative Obligations Regarding Program Participation.** During the term of this Agreement, the Participant:
   (a) warrants that (i) the Participant is not an employee of Enbridge or any of Enbridge's affiliates (as such term is defined in the *Business Corporations Act* (Ontario), referred to herein as **"Affiliates"**); and (ii) no partner, officer, director, or majority owner or shareholder of the Participant is an employee of Enbridge or any of Enbridge's Affiliates;
   (b) warrants that all information it has provided to Enbridge in its application to participate in the EnergyLink™ Program (or any component thereof), or in any updates to such information, is true and correct, and agrees to advise Enbridge of any changes to such information that may arise after the date hereof;

(c) consents to the obtaining from any credit agency or other entity such reference or other information as Enbridge may reasonably require at any time, and consents to the disclosure at any time of any information concerning the Participant to any such agency or entity;

(d) warrants that all subcontractors who perform work referred to the Participant under the EnergyLink™ Program shall at all times comply with the terms and conditions of this Agreement as if such subcontractors were the Participant hereunder, and upon request, will provide evidence of its subcontractors' compliance with the terms and conditions of this Agreement, including but not limited to insurance, *Technical Standards and Safety Act* (Ontario), *Workplace Safety and Insurance Act* (Ontario) and other requirements;

(e) will comply with all federal, provincial or municipal laws, regulations, codes and/or ordinances applicable to: (i) the Participant, its employees or subcontractors; or (ii) the Equipment, its sale, installation or servicing;

(f) will adhere at all times to Enbridge's program criteria, rules, safety guidelines and codes of conduct in dealing with Customers and in the performance of all work to it referred under the EnergyLink™ Program; and

(g) will conduct its business in a professional manner that will in no way compromise the standards of Enbridge or the EnergyLink™ Program.

The Participant acknowledges that any failure to comply with this Section 5 will constitute a breach of this Agreement.

6. **Customer Service Obligations.** The Participant will at all times maintain a high level of customer service and satisfaction during the term of this Agreement. Without limiting the generality of the foregoing, the Participant will:

(a) contact Customers within twenty-four (24) hours of its receipt of a referral;

(b) attend at the Customer's site (if requested) and provide a free initial written quote for all work referred to it under the EnergyLink™ Program;

(c) keep appointments or contact Customers in advance to reschedule;

(d) clean up the work area to each Customer's satisfaction after installation or service;

(e) prepare, install, adjust and service all Equipment according to manufacturer's specifications;

(f) in addition to (and not in place of) any applicable manufacturer's warranties, warrant to Customers that the Equipment and/or installation thereof provided by the Participant to Customers will be free from defects for a minimum of one (1) year from the date of installation;

(g) remedy any and all failures to conform to the warranty referred to in subparagraph 6(f) within seven (7) business days of notification by either Customer or Enbridge of such failure, or such other reasonable time period as may be agreed to by Customer in writing;

(h) at any time immediately correct any and all code or other violations relating to the Equipment, its installation or servicing;

(i) immediately take all necessary safety precautions and appropriate actions to remedy any unsafe condition related to the Equipment; and

(j) not mislead Customers or engage in any unfair or deceptive marketing or trade practice.

The Participant acknowledges that any failure to comply with this Section 6 will constitute a breach of this Agreement.

7. **Customer Satisfaction.** The Participant acknowledges and agrees that Enbridge may at any time inspect installations and/or contact Customers (in each case, with the Customer's consent), for the purpose of assessing the Participant's work referred under the EnergyLink™ Program.

8. **Customer Information.** The Participant shall hold all Customer information it receives by virtue of its participation in the EnergyLink™ Program, including but not limited to Customers' name, address, contact information, payment information, preferences, needs or requirements (the **"Customer Information"**), in strict confidence and shall not use the Customer Information for any purpose which has not been expressly consented to by the applicable Customer. In addition, the Participant agrees that it shall comply with all laws applicable to the personal information of Customers, including but not limited to the *Personal Information Protection and Electronic Documents Act*.

9. **Advertising and Use of Trademarks.** Enbridge may, in its sole discretion, provide branding, advertising, marketing material, program informational material, manuals, training material, software and other documents and items related to the EnergyLink™ Program (the **"Enbridge Materials"**) directly to the Participant. All Enbridge Materials shall remain the sole and exclusive property of Enbridge. The Participant will ensure that its use of the Enbridge Materials strictly complies with Enbridge's trademark usage guidelines in effect from time to time. Enbridge may at any time require that the Participant stop using, or alter its usage, of all or any part of the Enbridge Materials which have been provided to the Participant. In such case, the Participant shall immediately comply with any requirements communicated to it by Enbridge. Upon termination of this Agreement for any reason, the Participant will immediately:

   (a) cease use of all Enbridge Materials;

   (b) discontinue all use, whether oral or written, of the name and trademarks provided;

   (c) make no further representation to any Customer or prospective Customer to the effect that the Participant is an EnergyLink™ Program Participant or in any way associated with, connected with, or linked to the EnergyLink™ Program or Enbridge;

   (d) take all action required to remove any such references from all existing advertising or directory listings;

   (e) deliver to Enbridge any Enbridge Materials in the Participant's possession; and

   (f) deliver to Enbridge a certificate of an officer of the Participant certifying the Participant's compliance with this Section 9.

   The Participant acknowledges that any failure to comply with this Section 9 will constitute a breach of this Agreement and trademark infringement.

10. **Insurance.** The Participant shall at its own expense maintain and keep in full force and effect during the term hereof and for a period of two (2) years following the expiry or termination of this Agreement:

   (a) commercial general liability insurance having a minimum inclusive coverage limit, including personal injury and property damage, of at least Five Million Dollars ($5,000,000). Enbridge shall be added as an additional insured in the insurance policy. The insurance policy shall: (i) cover contractual liability, completed operations liability and owners'/contractors' protective liability; (ii) not exclude any activities that the Participant is likely to perform in connection with the EnergyLink™ Program, including work with live gas; and (iii) contain a cross liability clause;

   (b) automobile liability insurance on all vehicles used in connection with this Agreement and such insurance shall have a limit of at least Two Million Dollars ($2,000,000) in respect of bodily injury (including passenger hazard) and property damage inclusive of any one accident; and

   (c) non-owned automobile liability insurance and such insurance shall have a limit of at least Two Million Dollars ($2,000,000) in respect of bodily injury (including passenger hazard) and property damage, inclusive in any one accident.

   The Participant shall forthwith after entering into this Agreement, and from time to time thereafter at the request of Enbridge, furnish to Enbridge a memorandum of insurance or an insurance certificate setting out the terms and conditions of each policy of insurance (all such policies of insurance referred to as the **"Insurance Policies"**) maintained by the Participant in order to satisfy the requirements of this Section. The Insurance Policies shall be arranged with insurers acceptable to Enbridge, acting reasonably, and shall contain such terms and conditions as are reasonably acceptable to Enbridge. The Participant shall not cancel, terminate or materially alter the terms of any of the Insurance Policies without giving prior notice in writing to Enbridge. The Participant shall cause or arrange for any of its insurers under any one or more of the Insurance Policies to oblige itself contractually in writing to Enbridge to provide fifteen (15) days prior notice in writing before cancelling, terminating or materially altering the Insurance Policies under which it is an insurer.

11. **Compliance with Laws.** The Participant agrees to comply with the *Occupational Health and Safety Act* (Ontario), the *Technical Standards and Safety Act* (Ontario) and the *Workplace Safety and Insurance Act* (Ontario) and all other prevailing federal, provincial and municipal laws and regulations or any other laws or regulations in force which are applicable to the Participant, its employees or subcontractors and the work referred under the EnergyLink™ Program, and the Participant shall familiarize itself and procure all required permits and licenses and pay all charges and fees necessary or incidental to the due and lawful performance of all work referred under the EnergyLink™ Program. The Participant shall from time to

time, upon request by Enbridge, provide Enbridge with evidence of such compliance, and in particular, evidence from the Workplace Safety and Insurance Board, or its successor if any, that the Participant and its subcontractors are in compliance with and have paid all assessments and other amounts owing pursuant to the *Workplace Safety and Insurance Act* (Ontario).

12. **Indemnification.** The Participant agrees to indemnify, defend and hold harmless Enbridge and Enbridge's directors, officers, employees and agents (**"Indemnitees"**) from any and all claims, demands, losses, harm, costs, liabilities, damages and expenses of every nature and kind whatsoever (including without limitation legal fees and disbursements, investigation expenses, and adjuster's fees and expenses), resulting from or in any manner arising out of or in connection with or referable to:

    (a) any act, omission, default or negligence of the Participant, or its employees, representatives, subcontractors or agents;

    (b) any breach of this Agreement or any actual or alleged breach of an agreement between the Participant and a Customer; or

    (c) any defective, deficient or non-complying product, services or other items furnished by the Participant.

    Enbridge may elect to have its representatives accompany the Participant's representatives to any settlement negotiations or proceedings relating to any claim governed by this Section 12. Any release forms used in settling any claim governed by this Section 12 shall be subject to Enbridge's approval and shall be made in favour of both the Program Participant and Enbridge.

13. **Independence of Parties.** Neither party will be entitled to attempt to create or assume any obligation, express or implied on behalf of the other. This Agreement will not be interpreted or construed to create an association, subcontract, joint venture, partnership or franchise relationship between the parties or to impose any partnership or franchise obligation or liability upon either party. Under no circumstances will the Participant or any of its employees, representatives or agents:

    (a) represent themselves as employees, representatives, subcontractors or agents of Enbridge;

    (b) refer to Enbridge in any contract between the Participant and a Customer relating to work referred to the Participant under the EnergyLink™ Program; or

    (c) refer to Enbridge or use any Enbridge trademarks in any advertising or promotional materials, without having first received Enbridge's express written consent.

14. **Non-Exclusive Agreement.** The Participant understands and acknowledges that no promises or representations whatsoever have been made as to the actual or potential number of Customers that may be referred by Enbridge to the Participant under the EnergyLink™ Program. The Participant further acknowledges that in no event shall Enbridge be responsible for costs or expenses the Participant may incur, if any, to participate in the EnergyLink™ Program. This Agreement is non-exclusive in that Enbridge may refer Customers to persons or entities other than the Participant and the Participant may seek and accept referrals from persons or entities other than Enbridge.

15. **Termination of this Agreement.** Either party may terminate this Agreement, with or without cause, upon thirty (30) days written notice to the other. Further, Enbridge may terminate this Agreement immediately in the event the Participant breaches any provision of this Agreement. The obligations imposed under this Agreement that may be reasonably interpreted or construed as surviving the termination or expiration of this Agreement, including without limitation those obligations specified in Sections 5, 6, 7, 8, 9, 10, 12, 18, 20, 21 and 22, shall survive the termination or expiration of this Agreement.

16. **No Transfer/Assignment without Consent.** For the purposes of this Section, a **"Transfer"** means: (a) an assignment or other disposition of this Agreement in whole or in part (whether by operation of law or otherwise); (b) an assignment, sale or other disposition of any interest (whether in shares, partnership units or other interests) in the Participant which results in a change in the effective voting control of the Participant; or (c) a merger, amalgamation or other similar corporate reorganization involving the Participant. The Participant will not complete any Transfer without the prior written consent of Enbridge. Prior to granting its consent to a Transfer, Enbridge may require that the Participant (or its proposed successor) update, confirm, re-validate or re-issue all certificates, reports, documents or requirements set out in this Agreement. Any Transfer completed by the Participant without the prior written consent of Enbridge will result in the automatic termination of this Agreement. In such case, a party must reapply if it wishes to be an EnergyLink™ Program Participant. Subject to the foregoing restriction on Transfers by the Participant, this Agreement will be fully binding upon, enure to the benefit of, and be enforceable by the parties and their respective successors and assigns.

17. **Notices.** Unless otherwise set out in this Agreement, any notice or other communication given by either party to the other party under this Agreement will be in writing and will be deemed to have been duly given when: (a) delivered by hand; (b) received by the recipient if sent by nationally recognized overnight delivery service or by letter mail (with receipt requested); or (c) received by the recipient by any other reasonable method to extent the other party has evidence of the receiving party's receipt thereof. Either party may from time to time change its address by giving the other party notice of the change in accordance with this Section.

18. **Remedy.** The Participant acknowledges that any breach by Program Participant of this Agreement may cause irreparable injury to Enbridge. Accordingly, in the event of such breach or an impending breach, Enbridge will be entitled to obtain temporary restraining orders, injunctions and other equitable relief from a court in addition to and not in lieu of the right to seek damages and any other right or remedy afforded to Enbridge by law or otherwise.

19. **Waiver.** The failure by Enbridge to insist upon strict enforcement of any of the terms and conditions of this Agreement shall not constitute a waiver of such right.

20. **Governing Law.** This Agreement will be interpreted, constructed and enforced in all respects in accordance with the laws of the Province of Ontario and the federal laws of Canada applicable therein. The Participant will not commence or prosecute any action, claim, suit or other proceeding under or related to this Agreement other than in the Province of Ontario and hereby consents to the jurisdiction and venue of the courts in the Province of Ontario.

21. **Invalidity/Unenforceability.** If any part of any provision of this Agreement is invalid or unenforceable, the provision will be ineffective only to the extent of such invalidity or unenforceability without in any way affecting the remaining parts of the provision or this Agreement.

22. **Entire Understanding.** This writing represents the entire agreement and understanding of the parties with respect to the subject matter hereof and supersedes any and all previous agreements of whatever nature between the parties with respect to the subject matter. Unless otherwise set out herein, this Agreement may not be altered or amended without the written agreement of both parties.

23. **Counterparts.** This Agreement may be signed in one or more original, electronic or facsimile counterparts, each of which, when executed and delivered, shall be deemed to be an original, and all of which, when taken together, shall constitute but one and the same Agreement.

IN WITNESS WHEREOF the parties have entered into this Agreement effective as of the date first above written.

ENBRIDGE GAS DISTRIBUTION INC.	**PROGRAM PARTICIPANT:**
	______________________________ *[Write Complete Legal Name of Participant Above]*
Per: ______________________________ Name: Title:	Per: ______________________________ Name: Title:
Per: ______________________________ Name: Title:	Per: ______________________________ Name: Title: I/we have authority to bind the Participant.

SCHEDULE A – HVAC REFERRAL PROGRAM

This Program Schedule to the EnergyLink™ Program Agreement between Enbridge Gas Distribution Inc. (**"Enbridge"**) and ____ (**"Participant"**)

is entered into ____ *[Date]*.

1. **HVAC Referral Program.** As part of the EnergyLink™ Program, the HVAC Referral Program will connect Customers seeking the purchase and installation of or service for furnaces, boilers/hydronics, water heaters, fireplaces, air conditioning units, dryers, pool heaters, barbeques and other residential or commercial natural gas equipment and piping, with EnergyLink™ Program Participants. The terms and conditions of the HVAC Referral Program are set out in this Program Schedule. Enbridge reserves the right to amend the provisions of this Program Schedule at any time. Enbridge will provide EnergyLink™ Program Participants with such notice of revisions to this Program Schedule as it deems appropriate in the circumstances, including but not limited to by means of postings on the EnergyLink™ website or general mailings.

2. **Term.** This Program Schedule will terminate on ____________________, unless renewed for additional term(s) by Enbridge upon advance written notice to the Participant. As part of the renewal process, or at the request of Enbridge at any time, the Participant will update, confirm, re-validate or re-issue all certificates, reports, documents or requirements set out in this Agreement.

3. **Training.** The Participant agrees to attend computer training related to the EnergyLink™ Program and will keep confidential all passwords and content. The Participant and its employees will also attend and complete such additional training or orientation, from time to time, as may be required by Enbridge. All manuals, software and training materials provided to the Participant by Enbridge shall remain the property of Enbridge. In the event of termination, the Participant agrees to return all such items to Enbridge in accordance with the terms of this Agreement.

4. **Service and Program Obligations.** During the term of this Program Schedule, the Participant will:

   (a) operate a full service HVAC contracting business, capable of completing sales, installations, servicing, repairs and removals of Equipment;

   (b) contact Customers within twenty-four (24) hours of its receipt of a referral;

   (c) attend at the Customer's site (if requested) and provide a free initial written quote for all work referred to it under the EnergyLink™ Program;

   (d) ensure that all Participant property to which Enbridge Materials may be affixed (including vehicles or other property) shall be presentable and safe for their intended use;

   (e) participate in and actively support Enbridge's added load/DSM campaigns;

   (f) upon request, provide evidence of its, and its subcontractors', ongoing compliance with the terms of this Agreement, including but not limited to insurance, TSSA, WSIB and other requirements;

   (g) not use the EnergyLink™ Program or the EnergyLink™ Referral System (as defined below) in any manner intended to manipulate the number of referrals generated for the Participant; and

   (h) comply with such program criteria, rules, safety guidelines and codes of conduct relating to EnergyLink™ Program as Enbridge may specify from time to time.

5. **Reporting and Communications.** The Participant shall at all times maintain Internet service sufficient to meet its reporting and other obligations under this Agreement. The Participant shall check email and update the online EnergyLink™ referral system (the **"EnergyLink™ Referral System"**) each day, including weekends and holidays, in order to respond to Customer inquiries. The Participant shall promptly notify Enbridge in the event of lost passwords, erroneous information entered into the EnergyLink™ Referral System, suspected security breaches, or other software or reporting related concerns.

The Participant shall promptly provide Enbridge with such reports and updates as may be required from time to time, including:

(a) Updating the EnergyLink™ Referral System on the status of initial customer contacts and reporting the final status of the referral within twenty-four (24) hours;

(b) Providing information to Enbridge on natural gas equipment and DSM measures installed, including all natural gas up-sell opportunities closed; and

(c) Providing such other information as is requested by the EnergyLink™ Referral System.

The Participant acknowledges that Enbridge will be using the information entered into the EnergyLink™ Referral System to track and report on EnergyLink™ Program Participant performance, including close ratios, up-sell opportunities closed, Customer satisfaction levels, dispute resolution statistics and all other performance obligations identified in this Agreement.

The Participant will meet with Enbridge representatives on a regular basis, at the request of either party, to discuss its performance in the EnergyLink™ Program and to provide feedback to Enbridge on the EnergyLink™ Program.

6. **Participant Contact Information.** The Participant agrees to update, as necessary, their profile and contact information via the EnergyLink™ Referral System, including their mailing addresses, contact person(s), phone numbers, email address(es).

7. **Self-Suspension.** The Participant may at any time request that Enbridge cease providing it with referrals for a period of not less than two (2) weeks.

8. **Dispute Resolution.** The Participant shall at all times during the term of this Program Schedule have in place a written customer dispute resolution process consistent with the terms and conditions of this Agreement.

   In the event that Enbridge receives a complaint relating to Equipment installed or services performed by the Participant, the Participant shall contact the Customer within twenty-four (24) hours of notice of the complaint and use its best efforts to remedy the situation to the Customer's satisfaction within five (5) business days. The Participant will promptly repair, at no additional charge to the Customer, any Equipment installed or service performed that does not comply with the terms and conditions set forth in this Agreement. In the event that the Customer complaint remains unresolved after the Participant contacts Customer and/or attempts to repair the Equipment and/or service, the Participant shall promptly advise Enbridge. The Participant authorizes Enbridge to independently assess any Customer complaint (including by inspecting any installations and/or contacting the Customer) and make a final determination resolving the issue. The Participant agrees that any such determination by Enbridge will be final and binding upon the Participant.

   In the event that the Participant averages an escalated complaint rate of more than 10% for more than three (3) consecutive months, Enbridge reserves the right, in its sole direction, to suspend or terminate the Participant from the EnergyLink™ Program.

IN WITNESS WHEREOF the parties have entered into this Program Schedule effective as of the date first above written.

ENBRIDGE GAS DISTRIBUTION INC.	**PROGRAM PARTICIPANT:**
	______________________________ *[Write Complete Legal Name of Participant Above]*
Per: ________________________ Name: Title:	Per: ________________________ Name: Title:
Per: ________________________ Name: Title:	Per: ________________________ Name: Title: I/we have authority to bind the Participant.

HRAI The Heating, Refrigeration and Air Conditioning Institute of Canada

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- About HRAC
- Mission/Vision
- Member Advantage Programs
- Marketplace Distinction Program
- Membership Requirements
- Board of Directors
- Chapter/Provincial Groups
- Contractors Link
- HRAC Members in Good Standing
- HVACR Career Opportunities
- Right-Suite™HVAC Software
- Consumer Tips
- Contact HRAC

HRAC ✓ Member Company

Contractor Excellence in Action

The HRAC "Marketplace Distinction Program" takes advantage of the HRAC membership criteria that require members to verify their trade licenses and other qualifications. This program promotes members in the marketplace as "contractors of distinction" through traditional media and through partnerships with other consumer-oriented organizations.

HRAC also provides members with marketing tools such as a consumer-oriented Web site, advertising templates and a series of logos free of charge. Truck decals, patches, consumer pamphlets and business cards with the member company logo are made available to members in good standing at a reasonable cost.

HRAC
Contractor Excellence in Action

Home

The Heating, Refrigeration and Air Conditioning Contractors of Canada

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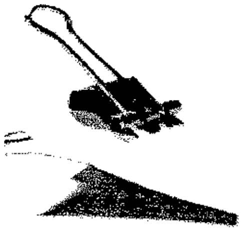
Application for Membership

Print



Membership Requirements [from the HRAC By-laws, Clause 5.2(c)]

"Members of the Heating, Refrigeration and Air Conditioning Contractors of Canada shall consist of corporations, sole proprietors or partnerships engaged in the business of contracting in equipment, parts, accessories and services for heating, refrigeration, air conditioning and/or ventilation within Canada. To be considered for membership in HRAC, applicants must demonstrate to the satisfaction of the HRAC Board of Directors (or those designated to act on behalf of the Board) that they comply with the relevant trade and business licensing regulations that govern their business activity within the jurisdiction(s) in which they conduct their business. Specifically, applicants must demonstrate (by way of verifiable photocopies of relevant documents) that they and/or their employees possess:

A. valid Trade Qualification Certificate(s);
B. valid Provincial fuel license(s) (e.g. gas fitter tickets);
C. valid municipal business license(s); contractors license(s) (where applicable);
D. Worker's Compensation Board coverage (unless exempt as a Sole Proprietor); and
E. $2,000,000 liability insurance coverage.

Applicants must also sign and agree to conform with the HRAC Members' Code of Ethics."

How to Apply for HRAC Membership (in Six Easy Steps)

STEP 1

Print and Fill in the Application Form or call 1-800-267-2231 ext. 245 to receive a copy by fax or mail). Providing all of the information requested up front will help to speed up the process by eliminating calls for clarification or further information. Please read carefully the membership requirements on the front page.

STEP 2

Attach All the Necessary Documentation. Please attach to the application form photocopies of the following:

A. Valid Trade Qualification Certificate(s);
B. Valid Provincial fuel license(s) (e.g. gas fitter tickets);
C. Valid municipal business license(s) and contractors license(s);
D. A Letter of Clearance from your provincial Worker's Compensation Board (unless exempt);
E. A certificate proving $2,000,000 liability insurance coverage.

NOTE: *Failure to provide sufficient evidence of these licenses and approvals may result in the rejection of this application by the HRAC Board of Directors. If you are not sure about the requirements in your jurisdiction call us at* **1-800-267-2231 ext. 245** .

STEP 3

Pay Your Membership Dues. Annual membership dues for HRAC include dues for your local HRAC-affiliated chapter (unless there is no affiliated chapter in your area) and HRAC-Canada dues. The membership dues schedule (on Page 3 of the application form) states the dues amounts for all HRAC's affiliated organizations for 2002-2003. Unless you have no affiliated chapter in your area, you must choose at least one (1) of the affiliated chapters listed on the schedule and include the appropriate dues in your HRAC total dues payment. If your business is in an area served by more than one local or regional group you may choose which one(s) you want to join.
HRAC-Canada national dues are scaled to company size as measured by number of employees and number of branch locations. If you have any questions, please contact the HRAC national office at **1-800-267-2231.**

Your dues payment must be forwarded with the completed application.

Since HRAC's fiscal year is July 1 to June 30, please note that dues received after July 31, 2006, and before April 1, 2007, will be pro-rated and a credit will be applied to the next fiscal year on your renewal invoice, which will be issued in May, 2006.

STEP 4

Read and Sign the Applicant Declaration. Please read the Declaration and the attached Code of Ethics carefully before signing.

STEP 5

Mail or Fax the Application Form, including attachments, to:

2800 Skymark Avenue
Building 1, Suite 201
Mississauga, Ontario
L4W 5A6
Or fax to: (905) 602-1197

STEP 6

Wait for Your Membership Package. The HRAC Board and staff must review your application for membership. Unless they have any questions or reservations, you will receive a membership package in the mail within a month.

HRAC
Contractor Excellence in Action

Home

The Heating, Refrigeration and Air Conditioning Contractors of Canada

HRAC Contractor Locator | **HRAC Contractors** | **Information Library** | **Contacting HRAC**

HRAC Members' Code of Ethics

Members of the Heating, Refrigeration and Air Conditioning Contractors of Canada (HRAC-Canada) agree to:

Instil the highest respect for the heating, ventilating, air conditioning and refrigeration (HVACR) contracting profession within their communities;

Maintain strict compliance with all laws, regulations and ordinances pertaining to the HVACR industry and business operations prescribed by federal, provincial and municipal governments;

Design, install, service and repair heating, ventilation, air conditioning and refrigeration systems in accordance with accepted industry standards;

Develop and maintain an understanding of proper equipment selection to assure customers of safe, dependable and comfortable performance;

Ensure that quality, honesty, integrity and good faith are hallmarks of contractors' business practices, including individual contractor sales, advertising, installations and service of HVACR systems;

Maintain a clean, safe, respectable and well-identified place of business commensurate with the high standards of the industry;

Increase the safety and efficiency of the HVACR contracting industry by supporting ongoing education and training of employees.

Develop and maintain the highest quality standards of customer service and nurture long-term relationships with customers;

Encourage and support business development in which skilled and professional HVACR contractors are empowered to provide high-level services to consumers and end-users;

Practice responsible equipment management (REM) by ensuring all equipment is decommissioned and disposed of in an environmentally responsible manner; and

Refrain from engaging in any business activity that benefits from cross-subsidisation from a regulated monopoly business.

HRAC
Contractor Excellence in Action

Home

The Heating, Refrigeration and Air Conditioning Contractors

HRAC Contractor Locator **HRAC Contractors** **Information Library** **Contactin**

HRAC Contractor Locator | HRAC Contractors: Your Smart Choice | Information Library | Contactin

The HRAC Contractor Locator will help you find an air conditioning, heating, ventilation, and/or refrigeration contractor in your area that is a Member in Good Standing of the Heating, Refrigeration and Air Conditioning Contractors of Canada. To know more about what HRAC Membership tells you about a contractor, go to "What HRAC membership means".

This system will search the HRAC Contractor Database for all companies that provide service within the given postal code. Click here for more information.
(en francais)

Postal Code Search

Enter a valid Canadian Postal Code. (Example: L4W 4Y4)

Your Postal Code:

● Residential ○ Business

Contractor Specialist in:
Residential:Select One

Number of Companies to Display:
● 5 ○ 10 ○ 20

☐ I have read and agree with the License Agreement.

The Heating, Refrigeration and Air Conditioning Contractors of Canada (HRAC) is a trade association representing contractor companies who provide products and services to the Canadian HVACR market. HRAC is dedicated to assisting and enabling its members to meet or exceed their customers' expectations by promoting the highest standards of quality, service, safety and integrity.

HRAC Member Company
Contractor Excellence in Action

When you see this logo, you know you're dealing with a properly licensed contractor you can trust.

HRAC requires its members to carry relevant trade, fuel safety and municipal licenses as well as workers compensation and liability coverage. A company's membership in HRAC not only tells you that the company is properly licensed but that they are also committed to continuous improvement through education and training.

What is an HRAC Member in Good Standing

Incentives and rebates

What are your home heating and cooling options? What questions should you ask when choosing a heating and air conditioning contractor? How can you keep your furnace running clean and safe? You'll find the answers to these questions - and more - in the links below

Consumer Guide to Heating Options (Furnaces & Boilers)

Consumer Tips on Choosing a Heating and Air Conditioning Contractor

Consumer Tips on Indoor Air Quality

View archived documents

Acrobat Reader is required to view the documents marked PDF. You can download Acrobat Reader from Adobe by clicking here.

Get Adobe Reader

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Just like our me contractors, HR committed to yo satisfaction and your comments. you can contact

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hrac@h

Telep
1.877.41

Fa
905.602

Mailing A

Submit

Company Name Search

Wondering whether a particular company is an HRAC member?
Type in the name of the company and find out! This system will list all businesses in the HRAC Company Database that include words beginning with, or matching, all the words you entered.

Enter the Company Name:

☐ I have read and agree with the License Agreement.

Submit

Qualifying for HRAC Membership

The HRAC Code of Ethics

HRAC Members Only

Tools for Contractors
English / French

HRA
2800 Skyma
Building 1,
Mississauga
L4W

Did a HRAC
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We would like tc
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What to Do i
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member compar

Filed: 2006-11-09
EB-2006-0034
Exhibit I
Tab 26
Schedule 10
Attachment
Page 1 of 17

ENBRIDGE

Business Case

for

EnergyLink™ Program

Project Number:	<project # - if applicable>
Prepared By:	Kerry Lakatos-Hayward
Date:	May 2006
Project / Business Sponsor:	Kerry Lakatos-Hayward Paul Green Wendy Cain

Table of Contents

Executive Summary

Through the EnergyLink™ Program Enbridge Gas Distribution intends to act in a market facilitation role to connect customers with pre-qualified EnergyLink contractors and retailers. EnergyLink™ Program is a strategic project that will increase the number of gas services in our franchise area; increase the installed base of natural gas equipment; and, increase the uptake of energy efficient products and services promoted through our DSM programs.

In scope for EnergyLink™ Includes development of a web and call centre enabled referral system for customers, a supporting contractor & retailer lead management portal. Members of the program would also receive a number of value propositions including access to the EnergyLink brand, exclusive sales campaigns, co-op advertising, training and other sales tools. Enbridge Inc.'s financing program would also be made available to members on a voluntary basis.

The financial assessment of EnergyLink™ Program indicates a 10 year NPV of $5.1M and an IRR of 27%

Background / Opportunity Definition

Current Situation

The purpose of the EnergyLink™ Program is to establish a viable, credible contractor and retail channel for residential and small commercial customers that will help us grow our business by increasing:

- the number of gas services in our franchise area,
- the installed base of natural gas equipment; and,
- the uptake of energy efficient products and services promoted through our DSM programs.

Enbridge Gas Distribution intends to act in a market facilitation role to connect customers with pre-qualified EnergyLink™ contractors and retailers. The rationale is if the natural gas product and service procurement process is simplified for mass market customers, their satisfaction with natural gas overall will be enhanced as will their propensity to install natural gas equipment.

The EnergyLink™ initiative is designed to provide customers with an easy, convenient experience. Customers will receive referrals for pre-qualified contractors and retailers of natural gas products, through whom they can access a range of value added services and incentives for natural gas installations. Communication and education on the benefits of natural gas will be a key feature of the program along with specific "call-to-action" offers. The enhanced website will be leveraged to deliver customer communications. The EnergyLink™ program also contemplates development of an installation service for natural gas white goods and lifestyle products to reduce key market barriers over the high first cost and "hassle" of acquiring and installing natural gas appliances.

In order to secure and sustain the loyalty of EnergyLink™ participants to natural gas products, we must ensure this relationship likewise supports their business objectives. Key to doing so is to provide EnergyLink™ participants with necessary sales tools, along with access to value propositions specifically developed for participants. Strategy Analysis

Strategic Assessment

The EnergyLink™ Program addresses the following strategic drivers:

- Market stagnation in growth of natural gas
- Fragmented industry has limited market penetration
- High energy prices
- Declining Average Uses
- Declining customer satisfaction and continuing customer confusion
- Customers want help navigating a deregulated industry
- Customers want convenience in accessing professional providers of energy products & services

Financial Assessment

The approved financial assessment indicates a 10 year NPV of $5.1M and a 27% IRR.

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Distribution Margin (revenue)	$ 52,258	$ 493,907	$ 1,306,948	$ 2,163,095	$ 3,037,017	$ 3,037,017	$ 3,037,017	$3,037,017	$3,037,017	$3,037,017
Less: O&M	500,000	800,000	800,000	624,000	848,720	-	-	-	-	-
Operating Cashflow before taxes	$ (447,742)	$ (306,093)	$ 506,948	$ 1,339,095	$ 2,188,297	$ 3,037,017	$ 3,037,017	$3,037,017	$3,037,017	$3,037,017
Less: Taxes	$ (701,428)	$ (773,104)	$ 41,752	$ 426,229	$ 726,736	$ 1,027,720	$ 1,034,471	$1,037,474	$1,040,196	$1,042,748
Operating Cashflow after tax	$ 253,686	$ 467,011	$ 465,195	$ 912,866	$ 1,461,562	$ 2,009,297	$ 2,002,546	$1,999,543	$1,996,821	$1,994,269
Add: CCA Tax Shield	$ 541,730	$ 642,871	$ 114,722	$ 28,825	$ 33,086	$ 34,381	$ 32,090	$ 30,302	$ 28,813	$ 27,508
	$ 795,416	$ 1,109,882	$ 579,917	$ 941,690	$ 1,494,648	$ 2,043,678	$ 2,034,636	$2,029,845	$2,025,635	$2,021,777
less: Capital Investment	$ 3,340,000	$ 1,076,800	$ 576,800	$ 594,104	$ 611,927	$ -	$ -	$ -	$ -	$ -
Annual Cash Flows	$ (2,544,584)	$ 33,082	$ 3,117	$ 347,586	$ 882,721	$ 2,043,678	$ 2,034,636	$2,029,845	$2,025,635	$2,021,777
PV factor @ 5.95%	0.9715	0.9170	0.8655	0.8170	0.7711	0.7278	0.6870	0.6484	0.6120	0.5777
5.95%										
Cumulative Cash Flows	$ (2,544,584)	$ (2,511,502)	$ (2,508,385)	$ (2,160,799)	$ (1,278,078)	$ 765,600	$ 2,800,235	$4,830,081	$6,855,715	$8,877,492
NPV of Cumulative Cash Flows	$ (2,472,144)	$ (2,441,808)	$ (2,439,110)	$ (2,155,147)	$ (1,474,478)	$ 12,959	$ 1,410,701	$2,726,887	$3,966,623	$5,134,548

10 Year NPV	**$ 5,134,548**
IRR	**27%**

Customer Assessment

EGD's market research clearly shows that customers want assistance in navigating the energy market place.

Over half of EGD's customers still believe that EGD fixes appliances. However, it should also be indicated that these customer perceptions are not linked to any significant confusion between DEEHS and EGD. The 2005 corporate reputation study shows that over 70% of customers understand the difference between DEEHS and EGDIn addition, 40% of customers would call Enbridge for appliance repairs, 15% would call DEEHS and 13% would call a local contractor. .

Areas of improvement for customer satisfaction include improved customer service quality, reliable service with no interruptions, lower cost and prompt response. In addition, customers want improved information on who to contact in case they were unable to resolve the problem.

Today, when customers want assistance we refer them to the yellow pages, HRAI or tell them to contact their current provider. This is not meeting customer expectations as customers are asking Enbridge to provide increased service in this area. This gap and market place confusion has eroded customer's view of Enbridge as a the place to go for natural gas and energy assistance.

Market penetration Rates of natural gas by appliance shows that since 2002 momentum has been lost as inroads made by natural gas has slowed significantly.

Natural Gas Market Penetration Rates by Appliance

Appliance	2000	2002	2004	2005
Forced Air Furnace	89%	89%	90%	90%
Water Heating	89%	86%	86%	86%
Dryer	19%	30%	30%	31%
Range	21%	27%	24%	27%
BBQ	14%	16%	18%	19%
Fireplace	26%	31%	32%	37%
Pool Heating	5%	4%	4%	5%
Mean Number of Appliances In HH	2.70	3.10	3.10	3.20

Customer Attachment: Market Penetration Rates by Appliance.

	2000	2001	2002	2003	2004
Furnace	59%	61%	64%	72%	73%
Water Heater	70%	33%	27%	22%	23%
Fireplace	17%	22%	24%	18%	13%
Range/Stove	8%	10%	11%	10%	8%
BBQ	4%	6%	4%	6%	4%
Dryer	7%	6%	6%	4%	3%

Industry Analysis

- Contractors represent a key channel for EGD, completing 76% or residential conversions in F2003
- HRAI have established a Market Distinction Program to position HRAI contractors as properly licensed contractors that customers can trust.
- Since unbundling, a few key players have emerged including DEEHS and Sears. ClimateCare and Service Experts have established contractor networks. See Appendix Two for a more detailed overview of the various organizations or associations.

- A similar situation emerges in the white goods area. With the closure of the 17 EHS/DEEHs stores as well as Home & Rural, the market place for retail products is very fragmented.

- Research conducted with J.C. Williams indicates that outside of the major players: Sears, Home Depot and Canadian Tire, the market place remains fragmented and highly regionalized. Mystery shopping with Sears, Canadian Tire, Home Depot indicates limited floorspace dedicated to natural gas, sales associates unaware of the benefits of natural gas and advise to "contact the gas company" to arrange for installation.

Other Utility Analysis

An analysis shows a number of utilities across North America have formalized channel partners programs to increase natural gas load.

- Oklahoma Gas offers its Choice Contractor Program through both contact centre and web channels.
- Pugent Sound and Keyspan (N/E USA) provides an online quote and referral service for gas conversion and gas fireplaces.
- Natural Fuel Gas has an Energy Partnership Program with local contractors in terested in participating in marketing programs to enhance the sale of natural gas
- Energen, Mobile Gas, Atmos Energy and PSE&G has a Preferred Dealer Network
- Atlanta Gas has an on-line natural gas appliance store
- SaskEnergy runs an online referral service with its SaskEnergy Network
- Gas Metropolitan offers a Gaz Met Authorized Partner program
- Terasen Gas offers a Qualified Dealer Program for Vancouver Island and Sunshine Coast

Concept Testing

- The EnergyLink™ Program concept was tested with customers in January 2006. Both the EnergyLink™ referral program and a fixed price installations service were well received, with customers indicating that this was a logical service for EGD to offer and a service they would use. Key to success, however, is EGD taking accountability and standing behind the EnergyLink™ contractors. As a result, strong business processes around pre-qualification, performance monitoring and customer dispute resolution have been strengthened to ensure that Enbridge can meet customer expectations. Customer feedback also indicated a strong preference for naming the program EnergyLink™ over other tested choices: EnergyConnect, Enconnect and EnLink.
- During the summer of 2005, a series of one-on-one meetings with contractors were held to determine how they wanted to work with Enbridge in the future. Contractors indicated that with the expiry of the non-compete clause in May 2006, they looked forward to working more collaboratively with Enbridge. Key areas of interest for collaboration

including an onbill financing program, customer lists/leads, sharing of market information and training.

- The EnergyLink™ k Program was introduced to the Industry Council in March 2006. The Industry Council is a select group of contractos, manufacturers and associations representing HVAC industry. The response to the Program was mixed. Members of the Council indicated that "contractors would be lined up at the door to sign up"; however, they were concerned about whether the EnergyLink™ program was taking the industry backward rather than forward. To address these concerns, EGD has been working with HRAI to modify the program to align the EnergyLink™ Program with the HRAI program.
- A solution definition phase was completed in December 2006, followed by a package evaluation. A comprehensive RFI process was conducted, out of which a decision was made to purchase the Aprimo Leads Management System. Aprimo will enable leads management distribution, tracking and follow up. Required customizations determined in scope include development of a leads generation engine to meet EGD's requirements to enable customers to select multiple contractors and customized reporting. See the Package Evaluation reports for further details.
-

Recommendation

Recommended Solution and Scope

The EnergyLink™ k Program recommended solution is development of a comprehensive channel partnership and management program that makes it easy, quick and hassle-free for customers to find the natural gas energy solutions they need. The Program positions EGD as a market facilitator to connect customers with professional contractors, leveraging superior service and the trusted Enbridge name

The Program will encompass the following elements:

- Development of strategic contractor and retailer channel partnerships to promote natural gas as the preferred energy source.

- Development of a web and telephone based customer referral service to connect customers with pre-qualified EnergyLink™ contractors

- Development of a focused, effective customer communication campaign supporting EnergyLink™ that re-positions Enbridge as a market facilitator, as the place to go to get their energy solutions. The campaign will have a strong branding focus around natural gas and getting the customer to think beyond gas for heating and water heating applications.

- Development of a EnergyLink™ Participant portal to enable members to manage their leads and business opportunities

- Development of educational and sales tools to motivate and enhance the channels to become a more effective sales channel of Enbridge and the gas industry.

- Development of other channel support tools including the Enbridge Gas Distribution EnergyLink brand, sales campaigns exclusive to EnergyLink™ participants and co-op advertising support. Softer support will also be provided via co-ordinated business planning with the participants and development of sales training around natural gas.

- Implementation of supporting management processes and technologies to support the overall initiative.

- EnergyLink™ Partners will also be offered a non-mandatory Enbridge Inc. Financing program to provide them with additional sales tools to increase the penetration of natural gas appliances. Participants will be encouraged to offer the customer with a wide range of payment options including cash, debit, visa, lines of credit, their financing programs and EI's program. This program will be run as a separate program from Enbridge Inc., however due to the Undertakings precluding the utility from offering this service directly.

Scope

- Development of an HVAC strategic contractor and retailer channel partnerships to promote natural gas as the preferred energy source. In scope Phase 1A July 2006
- Development of an Enbridge Inc. Financing program
- Development of an EnergyLink™ brand strategy
- Development of launch sales campaign support

- Implementation of supporting management processes and technologies to support the overall initiative.

- In scope Phase 1A July 2006

- Development of a web and telephone based customer referral service to connect customers with pre-qualified EnergyLink™ contractors

- Development of a EnergyLink™ Participant portal to enable members to manage their leads and business opportunities
-
- Development of a EnergyLink™ Participant portal to enable members to manage their leads and business opportunities
-
- Development of a focused, effective customer communication campaign supporting EnergyLink™ that re-positions Enbridge as a market facilitator, as the place to go to get their energy solutions. The campaign will have a strong branding focus around natural gas and getting the customer to think beyond gas for heating and water heating applications.

- In Scope Phase 1B November 2006

- Phase II the strategic contractor and retail partnership program will be expanded to white goods (dryers, ranges)
- Development of co-op advertising policies
- Development of educational and sales tools to motivate and enhance the channels to become a more effective sales channel of Enbridge and the gas industry.

- In Scope January 2007

- Phase III includes expanding the strategic retail partnership program to lifestyle products (patio heaters, pool heaters, campfires and bbq)
- Development of EnergyLink™ training support
- In scope Q1 2007

Out of Scope
Out of Scope for 2006 includes development of a virtual appliance store / catalogue. This will be investigated for 2007.
Also out of scope for 2006 includes development of a lifestyle web guide. This will be investigated for 2007

Total Project Costs

The high level project costs must be entered in the table below and the detailed month by month expenditure profile should be attached to this document

Cost Category	Project Account # / Cost Centre	Cost Including PST	Starting Fiscal Year & Month
Total Capital Costs	IT Capital (development of leads referral system) Regions (channel consultants)	$3.2M $500k	May 2006 June 2006
Total One-Time Expense Costs	IT Capital (sunk costs 2005/6)	$500k	June 2005-March 2006
Annual On-Going Costs	Mass Markets	$800k broken out as follows $100k sales calls $400k communications $50k risk management $50k claims $100k contractor	July 2006

Cost Category	Project Account # / Cost Centre	Cost Including PST	Starting Fiscal Year & Month
		support $100k technical advisors	
	Expected Project Life in Years:	10 Years	

Project Justification

Strategic Fit & Importance

EnergyLin EnergyLink^{TM} k is one of the key strategic initiatives being launched by EGD in 2006. It supports strategic objectives of growth and customer satisfaction.

Enbridge Gas Distribution intends to act in a market facilitation role to connect customers with pre-qualified EnergyLink contractors and retailers. The rationale is if the natural gas product and service procurement process is simplified for mass market customers, their satisfaction with natural gas overall will be enhanced as will their propensity to install natural gas equipment.

Financial Justification

The EnergyLink^{TM} has a 10 year NPV of $5.1M and IRR of 27%. The program has a positive cash flow starting in year 2,

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Distribution Margin (revenue)	$ 52,258	$ 493,907	$ 1,306,948	$ 2,163,095	$ 3,037,017	$ 3,037,017	$ 3,037,017	$3,037,017	$3,037,017	$3,037,017
Less: O&M	500,000	800,000	800,000	824,000	848,720	-	-	-	-	-
Operating Cashflow before taxes	$ (447,742)	$ (306,093)	$ 506,948	$ 1,339,095	$ 2,188,297	$ 3,037,017	$ 3,037,017	$3,037,017	$3,037,017	$3,037,017
Less: Taxes	$ (701,426)	$ (773,104)	$ 41,752	$ 426,229	$ 726,736	$ 1,027,720	$ 1,034,471	$1,037,474	$1,040,196	$1,042,746
Operating Cashflow after tax	$ 253,686	$ 467,011	$ 465,195	$ 912,866	$ 1,461,562	$ 2,009,297	$ 2,002,546	$1,999,543	$1,996,821	$1,994,269
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less: Capital Investment	$ 3,349,000	$ 1,076,800	$ 576,800	$ 594,104	$ 611,927	$ -	$ -	$ -	$ -	$ -
Annual Cash Flows	$ (2,544,584)	$ 33,082	$ 3,117	$ 347,586	$ 882,721	$ 2,043,678	$ 2,034,636	$2,029,845	$2,025,635	$2,021,777
PV factor @ 5.95%	0.9715	0.9170	0.8655	0.8170	0.7711	0.7278	0.6870	0.6484	0.6120	0.5777
5.95%										
Cumulative Cash Flows	$ (2,544,584)	$ (2,511,502)	$ (2,508,385)	$ (2,160,799)	$ (1,278,078)	$ 765,600	$ 2,800,235	$4,830,081	$6,855,715	$8,877,492
NPV of Cumulative Cash Flows	$ (2,472,144)	$ (2,441,808)	$ (2,439,110)	$ (2,155,147)	$ (1,474,478)	$ 12,959	$ 1,416,701	$2,726,887	$3,966,623	$5,134,548

10 Year NPV	**$5,134,548**
IRR	**27%**

Other Relevant Projects

The EnergyLink™ program is dependent on Enbridge Inc.'s Financing program to deliver a critical sales tool and value add for Energy Link partners as well as to reduce market barriers associated with high cost of natural gas appliances.

The EnergyLink™ program has some dependency on the CIS replacement project related to ESM and Isight interfaces.

Implementation Strategy & Timing

Schedule / Milestones

- June 2006 HVAC Expression of Interest (interest in other programs will be probed)
- July - September 2006 HVAC program sign up and soft launch
- October 2006 – final testing and launch of EnergyLink™ referral program
- November 2006 – "Hard launch" EnergyLink™ referral program and customer communication
- January 2006 launch of 'White Goods referral – phase 2
- March 2006 launch of lifestyle products – phase 3

Critical Success Factors & Project Risks

Critical Success Factors include the following:

- Strong participant sign up in all areas and program categories. EGD can clearly articulate the benefits to participants of the EnergyLink™ program
- Ability to access key resources for both program implementation as well as the on-going operation of the program.
- Implementation of On-Bill financing as soon as possible to deliver a key value proposition required by contractors and other participants.
- Referral system is clearly communicated to customers
- Business processes and RACI clearly mapped out and understood to minimize risk to EGD
- IT delivers the referral system on time, on budget. To do this the business must minimize "scope creep"
- Successive programs are quickly implemented to deliver the added load volume from white goods and lifestyle products.
- Despite strong interest from HVAC contractors, and willingness by EGD to work with the association to align the program with their Market Distinction Program, the association may threaten to take this to the OEB as a leveraging tactic.

Resource Requirements

See the Scope of Work for resource requirements to build the referral program
On the business side by 2007 we will require 8 additional channel consultants and sales analysts and 3 technical advisors

Communication Plan

Communication plans have been drafted for the following audiences

Contractors: advertising Expression of Interest and Application process for EnergyLink™. Major communication vehicles are existing channels including the contractor portal, flash fax and advertising in industry magazines.

Employees: employees will be regularly updated of the progress of EnergyLink™, particularly when a major push with external audiences are planned

Customers: customer communication plan has been drafted with different budgets contemplated and will involve magazine/newspaper ads and bill inserts.

Legal Requirements

A full legal contract (Master Service Agreement) along with program addenum's will be required by each EnergyLink™ participant. This will be a 15 month contract with an option by EGD to early renew after 12 months. During renewal, participant performance will be reviewed along with insurance and licenses before deciding whether to renew. The legal requirements are being structured this way for workload planning purposes.

Business processes for application processing, contractor monitoring and renewal have been drafted.

On-going Success Measures

On-going success measures include added load (m3)

Customer satisfaction from customers using the program will also be measured and reported as a KPI

From a contractor/retailer perspective, key ratios include up-sell ratio, close ratio and # claims/lead

Alternatives Considered

A number of alternative solutions were initially looked at from a qualitative perspective. These include forming a highly formalized, centralized dealer network similar to SDA arrangement. This was not quantified, as it was felt that there would be little acceptance for a very structured arrangement at this time. The other solution in essence contemplated running the EnergyLink™ program through HRAI. This was rejected for a number of reasons: (1) HRAI is not the only organization that EGD would want to work with in the future; (2) Although HRAI has a Market Distinction Program it was not deemed adequate enough in its current format to mitigate the risk and liability that EGD would face. For example HRAI does not require annual documentation review or $5M in comprehensive liability insurance. These are two key criteria that EGD would require. (3) HRAI would not adequately police its members and/or be able to resolve customer disputes to EGD's satisfaction. Appendix Two details a SWOT that was completed on various organization structures As such option 2 was not further evaluated.

Appendices

Appendix 1 – Expenditure Profile

Project Expenditure Profile:

Total Capital Costs:

Fiscal Yr	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
2003													0
2004													0
2005													0
2006	200	200					800	500	500	400	300	300	3200
2007													0
...n													0
Total													3200

Total Sunk Costs previous SOW (capital)

Fiscal Yr	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
2003													0
2004													0
2005	200		300										500
2006				200									200
2007													0
...n													0
Total													700

Ongoing Operating Costs:

Fiscal Yr	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
2003													0
2004													0
2005													0
2006		200	300										500
2007	50	50	50	150	150	50	50	50	50	50	50	50	800
...n													0
Total													1300

Appendix 2: Industry Analysis of Various HVAC Organizations

HRAC

Licenses/Trades Certification – must show proof of certification

- Gas Technician / Fitter
- Refrigeration Mechanics
- Electricians
- Sheet Metal

Membership Dues:

- National e.g. 11 – 20 Employees $475.00
- Affiliate e.g. Toronto $75.00
- Currently 295 organizations in our franchise

Note: Members have Access to MorEnergy Rental Program

CLIMATE CARE

Operates as a co-operative; Model: Home Hardware
Share purchases
Mission/Code of Conduct
Required membership in HRAC
Must attend ¼ ly meetings and be active in a committee
Examples

- Training
- Business Practices
- Membership
- Finance

Preferred supplies 40% - 30 days
Emphasis on training – each member must have a budgeted line item in their business operation for training
Bench marking against each member & Industry – 3rd Party Consultant
Structure – 5 executive, plus chairs of committee = Board of Management
Members get 1 vote
Credibility test on new applicants wanting to join
33 Climate Care contractors in Ontario

SERVICE EXPERTS

Division of Lennox International
Evolved in Canada from acquisition post unbundling 1999
Individual Company names remain: Examples

- Limcan
- Mersey Heating
- Francis Home Environment

Owned and managed by Lennox Retail Operations

- Previous owner or General Mgr responsible
- Accountable to Lennox Retail Operations

25 operate in our franchise area

- 2 – commercial only
- 5 – new construction
- 18 – residential sector

Note: Not restricted to carry Lennox only brands
Often aligned with HRAC but not a prerequisite

SEARS

HVAC business centrally managed
Sears Store locations – only provide kiosks for lead generation (19 in our franchise)
Leads centrally managed to outside sales associates*
Installation through sub contractors
Any Service performed by Sears employee
Focus on Heating, Air Conditioning, Fireplace and **Water heating

Notes: Full Enbridge franchise coverage
Not a member of HRAC

*Sears employees
** Also available to consumers for delivery only – non installed

DIRECT ENERGY

Corporate operations

- 9 territories in franchise * 51 EMC

Franchises

- 7 territories in franchise* 28 EMC
-

* as of March 2004. EMC are outside sales reps

Exclusive territory arrangements

- Cost to franchisee - % of business

Note: Direct Energy is not a member of HRAC
Franchisees who were members continue to be grandfathered
Rental program – Water heating

STRENGTHS AND WEAKNESSES

Franchise Coverage

Direct	High	
HRAC	Low to Medium	None in Niagara & rural Eastern
Sears	High	
Climate Care	Low to Medium	None in Niagara & rural Eastern
Service Experts	Low to Medium	None in Niagara & rural Eastern

Licenses and Certificates

- Policing All have some business processes

Web presence

All

Self Policing/Customer Satisfaction

Direct	High
HRAC	Low to Medium**
Sears	High
Climate Care	Medium to High*
Service Experts	High

* Individual companies
** Only policing of licenses, certificates and fees paid. No customer intervention

Leads System

All	Various levels e.g. HRAC's contractor locator is a web-enabled contractor finder

Customer Awareness/Knowledge

Direct	High
HRAC	Low – Marketplace Distinction Program
Sears	High
Climate Care	Low to Medium - localized
Service Experts	Low to Medium (leverage of the Lennox name)

Products offered (other than Heating, Air Conditioning, Water Heating & related HVAC products)

Direct	None
HRAC	Some offer fireplace (very limited)
Sears	Fireplace
Climate Care	Some offer fireplace
Service Experts	None

Opportunity: Network of Resources and Knowledge for Developing infrastructure for Non Traditional Products support

Direct	Possible
HRAC	Possible
Sears HVAC	Little
Climate Care	Little
Service Experts	Little

EXHIBIT K10.1

EXHIBIT

Tr: 62

Produce proposals or business plans relating to EnergyLink or to the earlier version of that entity, project Atocha

RESPONSE

Attached are business plans related to Project Atocha, dated August 2005.[1] These business plans clearly show that the goals of Project Atocha are to increase

- the number of gas services in our franchise area;
- the installed base of natural gas equipment; and,
- the uptake of energy efficient products and services promoted through our DSM programs.

The reference to financing (see K10.1, Attachment 2, p. 4) clearly outlines how the Enbridge Solutions Inc. financing program was being brought forward to support the utility's gas load growth strategy, *not* the other way round.

> Natural gas appliances intended for financing support added gas load growth in the regulated utility. These include core product categories: space heating, water heating equipment. In this category we [the Company] will finance other complimentary HVAC equipment including A/C as long as it does not compete with natural gas core product sales; white goods includes products with good growth potential including fireplace, ranges and dryers. Again, the Company will facilitate financing for complimentary products such as washers, refrigerators and dishwasher as a customer convenience as long as it doesn't compete with natural gas product sales. Gas lifestyle products are emerging categories and include pool heaters, patio heaters, barbeques, campfires, gas lamps, backup generators amongst others. Other energy products may be considered with the recommendation that the financing program stays close to the core strategy.

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[1] It should be noted that certain program elements related to Project Atocha are no longer being contemplated in EnergyLink as the program design has evolved since August 2005. Various elements no longer in scope include any limits to contractor participation (attachment 1, page 2), future performance based allocation of benefits beyond the development period (attachment 1, page 2) , QA reviews (page 2), any limitations to availability of financing to non-EnergyLink participants (page 3) and financing via a separate bill or credit card (attachment 2, page 4), various program criteria (appendix A1), various aspects of the customer dispute resolution process (appendix 1B). EGD also note that implementation of controls/processes have mitigated the risks/issues identified in the documents.

Witnesses: P. Green
W. Cain
K. Lakatos-Hayward
S. McGill

To be clear, financing on the bill is just one payment option available for customers. It is solely the contractor's choice on which financing/payment options it wishes to make available to customers. Enbridge Solutions Inc. has made a proposal to EGD to offer financing plans to contractors/customers; the Company has made it clear to ESI that the use of such a plan would have to be completely optional. In fact, it is the Company's position that it is beneficial to the market place to have a variety of on-bill financing options available to customers from third parties. EGD believes this customer and contractor choice is reflected in the Open Bill Access Settlement Agreement, whereby access to the bill is not limited to EnergyLink^{TM} participants, and whereby certain restrictions are placed on affiliates.

Witnesses: P. Green
W. Cain
K. Lakatos-Hayward
S. McGill

Business Models

Atocha – Strategic Contractor Channel Program

Wednesday August 10, 2005

Introduction:

The purpose of the Atocha Strategic Contractor Channel Program (SCCP) is to establish a viable credible HVAC contractor channel that will help us grow our business by increasing:

- the number of gas services in our franchise area,,
- the installed base of natural gas equipment and
- the uptake of energy efficient products and services promoted through our DSM programs.

If the natural gas product and service procurement process is simplified for mass market customers, their satisfaction with natural gas overall will be enhanced as will their propensity to install natural gas equipment. The SCCP initiative is designed to provide customers with an easy, convenient experience. The business model and value propositions together are intended to provide end-use customers with a simplified clearinghouse through an informed and reliable channel. Customers will receive referrals for pre-qualified HVAC contractors, through whom they can access a range of value added services and incentives for natural gas installations.

In order to secure and sustain the loyalty of SCCP members to natural gas products, we must ensure this relationship likewise supports their business objectives. Key to doing so is to provide SCCP members exclusive access to the value propositions offered.

Contractor Model (short description)

An HVAC channel model providing pre-qualified members exclusive access to a defined set of Enbridge value proposition offerings. In particular, the offers include sales promotions and incentives designed to drive add load, customer additions, new revenues (eg. Financing) and DSM for Enbridge.

Contractor Model (full description) with Benefits, Issues and Risks

Membership:

- Open to HVAC contractors that meet specified criteria and who apply to participate.
- Criteria for selection will include various items such as licensing, registrations, insurance, and demonstration of overall business health. Criteria for membership will be applied globally, regardless of region. (See Appendix 1 A)
- Ongoing membership will be contingent on adherence to defined criteria for:
  - code of conduct

  - performance to defined standards and QA levels, including customer relations & complaints handling, and/or
  - any required participation in sales promotions/programs
  - required participation in training programs
- The membership sign up process will be open and transparent based on the above-defined criteria; however, Enbridge will reserve the right to limit participation based on regional workforce management requirements and anticipated sales activity levels. One of the options being considered to expedite and manage the sign up process, is an initial “Expression of Interest”. In this process, the onus will be on the HVAC contractor to complete an application package demonstrating that they meet the set of predefined criteria. Applications received in the development period, but after such Expression of Interest process has closed will be considered on a case-by-case basis.

Contractual Requirements & Legal Liability & Risk Mitigation:

- A single, standard agreement applied to all qualified HVAC contractor members.
- The agreement will define an initial “program development” period allowing EGD the opportunity to assess the program and the flexibility to alter program parameters as required based on learnings during the development period.
- The agreement would allow for performance based allocation of benefits, including the development of a tiered relationship structure at some future date.
- Agreements will specify criteria for membership and ongoing performance standards and requirements. Criteria will cover: QA reviews and required performance levels, regular updates to contractor profiles and registration, licensing and insurance documentation, information exchange, timeliness of activities, appearance, how contractor represents the SCCP and its association with EGD etc. Contract will stipulate that breach of conditions for ongoing membership will result termination of contractor membership.
- Agreement would allow EGD or its representative to monitor and/or measure adherence to defined criteria (such as licenses, insurance, performance standards etc.).
- Agreement will clearly state that EGD is *not* in the HVAC business and specifically delineate that contractors are wholly responsible for service to the customer and any related issues, from mechanical to “mud on the floor”.
- Termination Clause: Agreement would specify that either party, at its discretion can terminate participation in the program. In particular, EGD, at its discretion can terminate program and related benefits to any or all contractors.
- Termination Notice: Terminations for cause: does not require notice period. Termination without cause: a notice period will be given..
- While EGD will not sign any agreement directly with SCCP subcontractors, the agreement will very clearly specify that SCCP members employing sub contractors will be responsible to bind any and all of their subcontractors to the terms and conditions of the standard agreement.

- SCCP members shall indemnify Enbridge from any litigation resulting from their actions and that of their employees and/or subcontractors.
- All SCCP members having subcontractors in their employ must at all times keep an up to date listing of all of its subcontractors, contractor licenses, insurances and other conditions as presented in the agreement and allow an audit by Enbridge at any time. We will also specify members must provide current listings and evidence of such insurance & licenses annually and at any time there is change to these items.
- SCCP members will maintain all necessary licenses and certificates pertaining to any services promoted in any way, be they offered directly or through subcontractors and/or affiliates.
- SCCP agreements will be with members' head-office. The agreements will cover all corporate, franchise and/or sub-contractor operations. (E.g, Direct Energy operates through both corporate and franchisee stores) and will stipulate non-conforming branches must be brought into line by the head office in order to avoid putting agreement in jeopardy.
- The agreement will delineate an arbitration process to resolve any issues/disputes between EGD and the contractor.

Distribution of Benefits:

- During an initial development phase, the number of leads provided will be based on geographic location. After the development period (suggest 12 months) leads & other benefits will be allocated according to pre-defined performance criteria such as sales closing, timeliness of dealing with lead, customer satisfaction etc. Performance criteria would be pre-defined and communicated.
    - E.g. Leads success ratio allocation: leads would be allocated according the individual contractor's overall sales closed during the development phase, as a percentage of the overall number of leads closed by all contractors.
- Value proposition benefits, such as leads, would be suspended for breach or lapse in membership criteria.
- SCCP Value proposition benefits will only be available to SCCP members (and Strategic Retail Channel Program (SRCP) members where such value propositions overlap). Specifically, financing will only be available to customers via SCCP and SRCP members
- SCCP member benefits currently contemplated are limited to the SCCP Value Propositions as defined in the attached document, however, at some future point, we may investigate the feasibility of additional benefits/value propositions for SCCP members. Any such value propositions related to core utility field services (e.g. unlocks, inspections etc.) that can be performed by our Strategic Distribution Alliance (SDA) Partners would first have to be discussed with SDA contractors as per our SDA agreement.

Operational Considerations:

- Assumes sales leads are managed in-house at EGD (Sales and Delivery groups).
- Mass markets (Sales & Opportunity Development) will be responsible for the design and implementation of the selection criteria and the process by which contractors are evaluated, selected, notified and signed on to the standard agreement.
- Mass markets (Sales & Opportunity Development) will be responsible for the detailed program design and implementation, including the specific details of the offerings to the SCCP contractors and their customers, as well as the benefits allocation processes and implementation.
- Ongoing monitoring of various terms and conditions of membership will be conducted. For instance, some or all of the following will be monitored: licenses, registrations, insurances, adherence to TSSA & industry standards, as well as any additional performance standards/criteria defined by EGD. The anticipated method to resource such monitoring is via a 3rd party organization managed through the EGD Risk Management department. IDS is the 3rd party organization that Risk Management currently engages to provide insurance and license monitoring services for EGD. We would likely expand the scope of this engagement to cover the SCCP requirements.
- Sales & SPIFS Tracking & Accounts Payables:
  - Some possible options for tracking / reporting sales and any related accounts payables are:
    - Contractor reporting, potentially with periodic audit of claimed sales.
    - Coded program SPIF/coupons requiring contractor /customer completion and both customer and contractor signatures.
  - Accounts payables for SPIF will be upon sales validation (such as copy of invoice) as above and once validated, paid in accordance with our existing accounts payable terms.
- Leads Management & Reporting:
  - Leads allocation based on location during the development period, thereafter by performance criteria,
  - Contractors must respond to lead within an EGD defined period of time,
  - Leads status reporting required from SCCP members as defined by EGD.
- Customer Relations:
  - Contractor performance standards, as defined in agreements, will be promoted to customers.
  - Contractors will be portrayed as independent, non-affiliated businesses that have demonstrated defined standards and qualifications; however customers will be advised to complete their own due diligence.

- Customer complaints regarding contractor performance will be directed to the contractor in question if they have not already done so. If the customer has contacted the contractor with no resolution, EGD will then intervene. (See Appendix I B Proposed Customer Complaints Process) EGD will track such complaints & contractor efforts to resolve as part of criteria for ongoing membership.
- All SCCP referrals and any and all documentation referencing this program will carry a disclaimer such as the following:

  > "SCCP members are independent contractors and have no authority to enter into any obligations, written or implied, on behalf of EGD. While the contractors have pledged to EGD that they will maintain a high level of customer service and satisfaction, EGD does not and cannot control the work of the contractors, nor does EGD in any way warrant installations or service work performed by program contractors."

- Benefits:
  - Potential to ensure a level of quality and performance in the HVAC industry.
  - A single standard contract streamlines the administrative process of signing up partners versus custom contracts.
  - Qualified HVAC contractors can participate.
  - Development period provides the opportunity to fine tune the program and thereafter allocate leads and other benefits based on performance.

- Risks:
  - Ongoing administration of agreements will be cumbersome and costly for Enbridge in terms of management, time and resources.
  - Increased potential liability for EGD in providing customers with contractor referrals.
  - Push back by non participating/non-qualifying HVAC contractors, possibly through regulatory channels.
  - Contract Development:
    - Difficult to develop structure and specific details of agreement such that customers, SCCP members and Enbridge expectations are met.
    - Customized Contracts: While our objective is to develop one standard contract, customized contracts will likely be required for certain players, for example, Sears, Direct Energy, Lennox/Climate Care. This is a risk in that it will add complexity to the initiative and will call into question member equality.
  - Contractor Participation: While we anticipate there will be many willing participants, until we can validate the attractiveness of the proposed value

propositions, we do not know that they will attract the right contractors to the program and/or compel enough contractors to participate.

- Issues:
    - The agreements must indicate that Enbridge will deliver on the value propositions only to the extent possible within our budget limitations and will be subject to program changes ongoing.
    - EGD will be in the role of "watchdog" regardless of the positioning we put forward in the marketplace.
    - The anticipated volume of contractor participants will make for a complex contract administration. Depending on whether or not we limit the number of members, the initiative will require additional resources to implement and monitor. Additional resource requirements are anticipated in the areas of: monitoring licences, registrations etc., customer relationship/customer complaints and sales promotions that impact operations (E.g. that drive service installations).
    - We will need to do further work to determine the number of contractors required for program success, and how we will ensure the ideal number of contractor participants.
    - Similarly, this initiative will require significant resources to manage and administer leads and other member benefits (either for development of in-house capabilities or to procure a 3rd party to manage and administer).
    - Requires the development and delineation of fair criteria that ensure key players can be involved in program and that are defensible in front of the OEB and intervenors.
    - We will need to delineate the required documentation or process to demonstrate financial health. Dunn & Bradstreet checks is the anticipated process for demonstrating financial health (see Appendix 1 A). D&B checks will not be possible on companies who have not established a credit history. This will have the desired effect of precluding participation from companies who have not established such a track record.
    - The qualifying criteria will be applied globally, regardless of region, however they will be designed such that smaller locally recognized and credible HVAC contractors can be selected. The ability of the criteria to both set an appropriate standard, yet still admit smaller contractors, is an extremely important component to the SCCP program credibility. For example, the criteria must ensure that subcontractors to larger "prime" HVAC contractor organizations do not have an unfair advantage over sole proprietorship businesses. Any such perception could potentially jeopardize municipal relations, and could undermine any system expansion efforts in such areas.
    - While we will not limit the number of contractors covering any given area of our franchise, we will however need to ensure sufficient coverage across our regions in order to ensure timely customer service.
    - Clear and complete messaging will be required on:

- how to qualify
- how members will be rated over the initial development period and
- how future benefits, in particular leads, will be awarded based upon performance during the initial development period.

APPENDIX I A Contractor Qualifying Criteria

- Licenses, Registrations & Insurances: Members must provide copies of all applicable business and technical licences and registrations including TSSA, WSIB and WHIMIS training and all appropriate insurances.
- Overall Business Health: Members must be willing to demonstrate the health and viability of their business as indicated by:
    - number of brands represented & other services provided,
    - financial statements,
    - length of time in business (for instance, a minimum of one year),
    - supplier references (suggest minimum 4),
    - customer references (suggest minimum 6),
    - number of branches and/or employees (installers, service technicians & sales force) including sub contractors relationships & service area coverage,
    - level of advertising,
    - current participation in Enbridge programs,
    - customer service quality (customer response timeframes, customer complaints processes etc.),
    - after-sales procedures.
- Members must provide one year limited warranty for parts and labour on all new equipment delivered and installed (if not already covered by manufacturer).

APPENDIX I B Sample Customer Complaints Procedures

In the event a customer is dissatisfied with the service received from a Contractor as part of the program, the contactors have agreed to participate in the following steps designed to help address the customer concerns.

- Complaint to be submitted in writing and to include:
    - a copy of the quote, contract and any other pertinent information,
    - company name,
    - the name of the person with whom the customer tried to resolve the complaint..
- All complaints to be evaluated by Channel Consultant.
    - Consultant will notify the contractor of the complaint.
    - Consultant will work with Contractor and customer to reach a settlement that is fair to both parties.
- If an agreement cannot be reached, the Consultant will refer the matter to the Better Business Bureau and notify customer and contractor that the complaint is being referred.
- An internal EGD SCCP board is in place to hear the issue and the Contractor in question could be removed from the program if found to have not fulfilled his agreement to EGD and the customer.

APPENDIX II Optional Features of the Model

Various features and options may or may not be included as part of this model:

1. Web portal to deliver and administer customer and contractor offers, business tools etc.:
   - virtual “one-stop” shop.
   - web-based storefront,
   - customers log into Enbridge site for information, features & benefits, promotions, installation procedures, manufacturers and contractors,
   - can be utilized to administer contract adherence, for e.g. flags EGD on expiration and renewal dates for insurance, licenses and/or fitter licenses,
   - web portal space available to SCCP members, possibly other third parties who do no directly compete with the SCCP members (e.g. manufacturers, electricians, independent fitters); subject to regulatory review and approval, a fee may be charged for use of such space,
   - provides links to other relevant website, in particular to SCCP members sites and to those of relevant manufacturers etc.,
   - decision analysis tools for end-use customers, such as financial payback and/or savings calculations on appliance conversions to natural gas.

2. Partner with Union Gas to offer the contractor program across Ontario:
   - joint program and value proposition offerings,
   - shared expenses for advertising and promotion leverages resources,
   - minimizes existing confusion among those HVAC members who conduct business with both utilities,
   - Ontario wide industry focus,
   - strong manufacturer/Distributor support,
   - leverages EGD & Union brands and strengthens the overall branding of natural gas,
   - stronger voice in the provincial and federal political arenas,
   - Improved customer satisfaction: Customer confusion and frustration minimized by avoiding circumstances where customers cannot access offers promoted by the other utility (for example, when customers visit retail outlets, such as Home Depot, outside their own utility’s franchise area.

   Issues Related to Partnership with Union:

   - different market compositions (in terms of relative proportions of the various segments) and different culture at the two utilities,
   - We need to validate Union’s interest in partnering with EGD on this initiative and understand if and how it supports their business objectives.

Risks Related to Partnership with Union:

- slow to Implement,
- aligning Business Practices – possible “show stopper”,
- disparities Budget & Business Case justification processes,
- increased costs.

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Value Propositions

Atocha – Strategic Contractor Channel Program

Wednesday August 10, 2005

Value Propositions (short descriptions; not in order of importance)

- Proposition A – Referrals
- Proposition B – Contractor Portal
- Proposition C – Financing Options
- Proposition D – Training
- Proposition E – Bursary Program
- Proposition F – Co-op Advertising Program
- Proposition G – Sales Incentives
- Proposition H – Exclusive Sales Promotions
- Proposition I – Market Intelligence Sharing

Value Propositions (full definitions/descriptions)

Proposition A –Leads

End-use customers provided various methods to contact EGD to receive referrals to qualified independent contractors according to customer defined parameters (e.g. desired service, contractor skill set, location, lowest price or quote)

- Sales leads distributed by EGD to the Strategic Contractor Channel Program (SCCP) members using pre-defined algorithms or automated engines.
- Leads will be generated by EGD from our databases and marketing activities.
- Customers will have two options for accessing a referral: the web and a 1-800 toll free number.
- Customers will be provided names of three SCCP members matched to their geographic location and service needs; Additional referrals will be provided at customer request if for any reason they are not satisfied with the initial three.
- Referrals will rotate in heavily concentrated SCCP member areas.
- Customer will have the option to call the contractors directly or alternatively, contractors will be given customer name and are expected to contact them within a defined number of business days.
- EGD guidelines will be put in place to assist the customer in what to look for in a contractor (see Appendix I for a sample “Tips for Selecting a Contractor”).

Value to End-Use Customers:

- Customer is provided with a contractor referral for gas equipment purchase & installation,
- Easy, convenient method for finding qualified contractor,
- Peace of mind when selecting an EGD SCCP member:
  - EGD will not guarantee the contractor's work but facilitates the customers' selection of a contractor who meets a defined set of criteria.

Value to SCCP members:

- Pre-qualified sales leads in support of growing their business: these leads are of more value than cold calls; in the case of some targeted campaigns our internal channel consultants could pre-qualify the call and/or work with the contractor to close the sale, Differentiation from other contractors,
- Lower cost of doing business (versus generating those leads themselves).

Value to EGD:

- Addresses our customers' desire that we provide gas contractor referrals,,
- Enhanced channel for growing our business & achieving our targets regarding fuel switching, added load, customer additions, DSM,
- Data acquisition through SCCP reporting,
- A dedicated sales channel providing the opportunity to target sell specific customers/products (E.g. By geographic area, age of home etc.) .

Proposition B – Contractor Portal

- Management and reporting tools for contractors
  - Vehicle for maintaining and updating contractor information. Contractors will be required to complete regular updates as warranted by any changes.
  - SCCP members will receive annual electronic reminders to complete a review and validation of their profile information. Copies of all such updates will be made available to a third party company engaged through Risk Management (for example IDS) to validate profile information, or, if we do not engage such a third party, then EGD Channel Consultant would access the profile information to complete "spot-checks" to validate profile information submitted.
  - Contractor responds to customer referral inquiries via a link to the customer online referral service.
  - SCCP contractors would respond to customer referrals with quotes based on in-home visits, or at minimum, based on home & lifestyle profile information provided by the customer.

  - SCCP contractors must have email and be able to communicate electronically with EGD and end use customers.
  - Access to SCCP specific promotions and incentives and method for submitting spiffs for processing by EGD.

Value to End-Use Customers:

- Contractors submit quotes back to the customer in a standard format via the online forum allowing easy comparison of multiple quotes.

Value to SCCP members:

- Enhanced marketplace reach through access to high profile, high value added portal,
- Access to relevant business tools & support,
- Manage SPIF and EGD campaigns,
- Improved workforce efficiency through up to date information of status of leads.

Value to EGD:

- Check status of leads provided to SCCP members, manage specific campaigns and related budgets,
- Reduce administrative costs associated with running SCCP program (automate collection of insurance / contact information),
- All leads reporting and sales numbers to be reported on line for greater accuracy and reduced paper handling,
- Facilitates performance target management (understand value of each SCCP member) and SPIF payouts,
- Addresses customers' needs for convenient, time saving method to navigate through a fragmented industry,
- Additional channel to support our growth and business targets ,
- Enhance the perceived value-add of EGD, and thereby our customers satisfaction,
- Enhances the natural gas brand,
- Increase burner tip opportunities,
- Cost effective method for information sharing with contractors and customers,
- Possible "One Tonne Challenge" capture and tracking method,

Proposition C – Financing Options

- This value proposition is a fee-for-service business to provide a convenient, seamless financing option for residential and small commercial customers who wish to purchase natural gas appliances.
- A business case is being finalized for consideration by Enbridge Inc. to offer flexible financing vehicle for customers as an unregulated offering. Key aspects of the financing option will be competitive interest rates, deferral offers, flexibility, high customer acceptance & recognition as well as convenience; however, due to cost considerations and timing of the new CIS implementation, an on-bill financing offer may not be brought forward until the 2008 time-frame. The business case has recommended that Enbridge look at other financing vehicles that would offer comparable benefits for SCCP partners and customers, including a 3rd party, Enbridge branded financing program and/or Enbridge credit card option.
- Under the initial 3rd party financing option proposed – an Enbridge branded financing program – the customer would receive a separate bill from Enbridge for the financing transaction. The 3rd party financing Company would perform all back office support including customer care functions (billing, call centre), credit & collections, funds disbursements. Enbridge would make the financing offer open to SCCP partners and be responsible for marketing of the program. To achieve the overall Atocha growth strategy, Enbridge may look at back-stopping debt in segments where credit approvals are expected to be low. As a fee-for-service business, under this program, Enbridge would charge the customer a spread over the 3rd party's interest rate and recover that from the 3rd party financing company as an upfront fee.
- Under the on-bill financing business model proposed for later implementation, the financing transaction will be billed on the customer's existing natural gas bill. In this, the 3rd party financing company would have title to the receivable, but would look to Enbridge for recourse. As such, Enbridge would take on the bad debt risk which would be recovered, along with other costs, through a financing spread charged on each transaction (this spread is approximately 5% over the base financing rate). Services Enbridge would provide via ABSU include billing, credit & collection, receivable/cash management and customer care services to gas contractors, retailers as well as their independent financing partners.
- Benefits to these business partners include lower bad debt risk & faster cash conversion cycles than otherwise achievable from entering into separate billing arrangements; lower O&M costs and overheads by working with a large established utility, access to a bill as a marketing channel as well as higher sales closing rates and sales levels.
- Natural gas appliances intended for financing support added gas load growth in the regulated utility. These include core product categories: space heating, water heating equipment. In this category we will finance other complimentary HVAC equipment including A/C as long as it does not compete with natural gas core product sales; White goods includes products with good growth potential including fireplace, ranges and dryers. Again, we will facilitate financing for complimentary products such as washers, refrigerators and dishwasher as a customer convenience as long as it doesn't compete with natural gas product sales. Gas lifestyle products are emerging categories and include pool heaters, patio heaters, barbeques, campfires, gas lamps, backup generators amongst others. Other energy products may be considered with the recommendation that the financing program stays close to the core strategy.

Value to End-Use Customers:

- Convenient point of purchase financing for large purchases and installations,
- Convenience of payment through their existing Enbridge bill (later),
- Access to additional credit.

Value to SCCP members:

- Enhanced customer offer,
- Additional sales / business in those situations where access to easy financing is a determining factor,
- Reduced receivables risk,
- Evens playing field with Direct Energy (with on-bill financing),
- Increased profile: Contractor name and phone number appears on the bill when their customer finances the purchase on their gas bill, increasing the potential for repeat business,
- Possible contractor specific loyalty rewards for redemption against gas purchases,
- Potential for pre-approved customer financing.

Value to EGD:

- Increases the penetration of additional gas appliances and supports electric to gas fuel switching programs, both of which grow gas distribution margin in EGD,
- Improves EGD's ability to control and leverage its external distribution channels by providing its channel partners with a highly value added sales tool - without on-bill financing, other elements of Utility's Atocha growth strategy are at significant risk,
- Creation of a contractor channel that can be used to deliver other Enbridge growth platforms to a shared customer base,
- Tests the consolidated energy bill concept and drives traffic towards the bill through on-bill financing; also minimizes risk from vendor consolidated billing,
- Opportunity to consider fixed-price plan offers for customers (i.e. define a set payment according to what customer can afford; number of payments determined from payment amount),
- Provides an additional marketing channel (e.g. ability to provide special and/or limited time offers to finance customers) to promote additional burner tip sales.

Proposition D – Training

- Various courses and business support tools to support the success of our SCCP members
- Courses would cover a variety of topics, potentially including:
    - General business:

        - (E.g. Business Values, New Business Development Opportunities (such as Maintenance Programs), Marketing, Sales, Motivation, etc.)
    - Product Knowledge and/or Facilitated Manufacturer Sessions:

      EGD facilitates manufacturer products and installation training,
        - New technology information,
        - Environmental and/or cost savings analysis.
    - Government & Utility Programs & Offers:
        - (e.g. DSM & Add Load Programs, Energuide , One-Tonne Challenge).
    - Marketplace Knowledge:
        - (e.g. Consumer Trends, Customer needs and wants etc).
- Business/Sales Support tools, potentially:
    - On-line savings analysis tools to support conversions,
    - On-line information resources,

Value to End-Use Customers:

- SCCP members have greater knowledge & skills that translate into improved service and better information for end-use customers .

Value to SCCP members:

- Enhanced skills and knowledge to give them an edge in the market,
- Raise level of professionalism among SCCP peers.

Value to EGD:

- Increased knowledge and professionalism of SCCP partners results in improved customer satisfaction,,
- Enhances the overall value proposition of the EGD SCCP,
- Increased sales due to better trained and expanded third party sales force.

Proposition E – Co-op Advertising Program

- EGD provides co-op support to SCCP members for various promotional campaigns and/or marketing initiatives,
- Co-op support and allocation thereof is subject to EGD annual budget and business planning,
- Potential use of a natural gas brand affiliation logo (but not the Enbridge logo).

Value to End-Use Customers:

- Greater visibility of SCCP members ensures customers have knowledge of this option for contractor selection,
- Increased awareness of SCCP and its benefits.

Value to SCCP members:

- Leverage their promotion & advertising efforts,
- Increase profile through SCCP,
- End-use customer recognize SCCP partners as qualified providers.

Value to EGD:

- Leverage our promotion & advertising efforts,
- Consistent promotion of SCCP members – increases recognition overall,
- Increased end use customer awareness of EGD value add services,
- Increase knowledge & awareness by end-use customers regarding who to contact,
- Positioning and branding of natural gas and new natural gas products available which could enhance their lifestyle,
- Potential participation by third party manufacturers and suppliers.

Proposition F – Exclusive Sales Campaigns and SPIFFS

Exclusive sales campaigns and spiffs for SCCP members only.

Value to End-Use Customers:

- Motivated SCCP contractor should result in better service and effort.

Value to SCCP members:

- Competitive advantage through additional cash &/or value add offers to help drive their business,
- Increased sales,
- Opportunity to reduce business peaks and valleys.

Value to EGD:

- Greater results through focused campaigns that motivate the SCCP channel,
- Targeted product promotions,

- Enhanced branding,
- Strengthened SCCP relationships and loyalty.

Proposition G – Market Intelligence Sharing

- Through collaborative business planning initiatives, EGD provides SCCP members market information based on our research and data analysis, and in accordance with PIPEDA, to assist them in their business development.
- The information provided would be the same for all members regardless of sales performance during the development period.
- Examples:
    - NonCOMs
    - Inactive services
    - Locked meters
    - Targeted customers with low usage (E.g. – baseload only customers)

Value to End Use Customers:

- Better targeted marketing by SCCP members will mean that to some extent, customers will be more selectively approached with services & offers that better meet their needs.

Value to SCCP Members:

- Improved efficiency & effectiveness of sales & marketing efforts, leading to competitive advantage,
- Leads generation for slow periods,
- Opportunities to break into markets which were previously a weak business endeavour for them due to lack of credible market intelligence.

Value to EGD:

- Improved efficiency of contractor channel helps drive our targets,
- Loyal and motivated SCCP channel due to greater exposure to all our customers,
- Strengthens the NG brand and the Enbridge brand.

APPENDIX 1 Sample "Tips for Selecting a Contractor"

Avoid any company that offers to give estimate without providing an on-site inspection of equipment.

A qualified contractor will survey and provide a heat-(loss/gain) calculation for your home. Many existing furnaces aren't sized properly and better contractors provide equipment to meet your home's load requirements precisely and efficiently.

A good company will provide a written proposal that clearly outlines the work to be done and the agreed-on price.

A reliable contractor will provide more than one furnace choice and annual operating cost estimates for each option. Know the costs, quality and savings potential of the furnace and or accessories you are buying.

A contractor should ask about heating and cooling problems experienced with your old equipment, and then offer understandable solutions.

A contractor will usually have a financing plan available

Most reliable contractors offer extended service agreements that include maintenance inspections. This is your insurance against the unexpected.

A well-trained, up-to-date contractor won't try to discourage you from purchasing high-efficiency equipment. If he/she does, get a second opinion.

A good contractor is professional. Employees should be prompt, courteous, neat, well groomed and be willing to offer identification.

A reputable contractor should have an office facility. You should be welcome to visit it. You should be welcome to visit it.

Qualified contractors recognize the importance of employee training. Untrained employees mean installation headaches and a system that might not meet your energy needs.

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Strategic Contractor Channel Partnership Program: Stakeholders Checkpoint

August 15, 2005

Prepared for Enbridge Gas Distribution

Objectives

» Objectives:

- Establish a common understanding of the Program including scope, approach and schedule
- Identify critical issues that may impact the success of this initiative
- Assist in further identifying Business Processes impacted or required to support the proposed Business Model and Value Propositions
- Obtain approval in principal on the proposed Business Model and Value Propositions

Agenda

- Program Overview
  - Scope
  - Approach & Schedule
- Business Model
- Value Propositions
- Business Processes
- Next Steps
- Wrap-up

Program Overview: Scope

- We will establish and implement strategic HVAC contractor channel partnerships to promote Natural Gas as the preferred energy source for mass market customers.
- We will educate & motivate the partnerships by providing the tools required for the contractor channel to become a more effective sales channel of Enbridge and the gas industry.
- We will define, develop and implement value propositions, as well as undertake collaborative business plans with our channel partners.

Program Overview: Scope

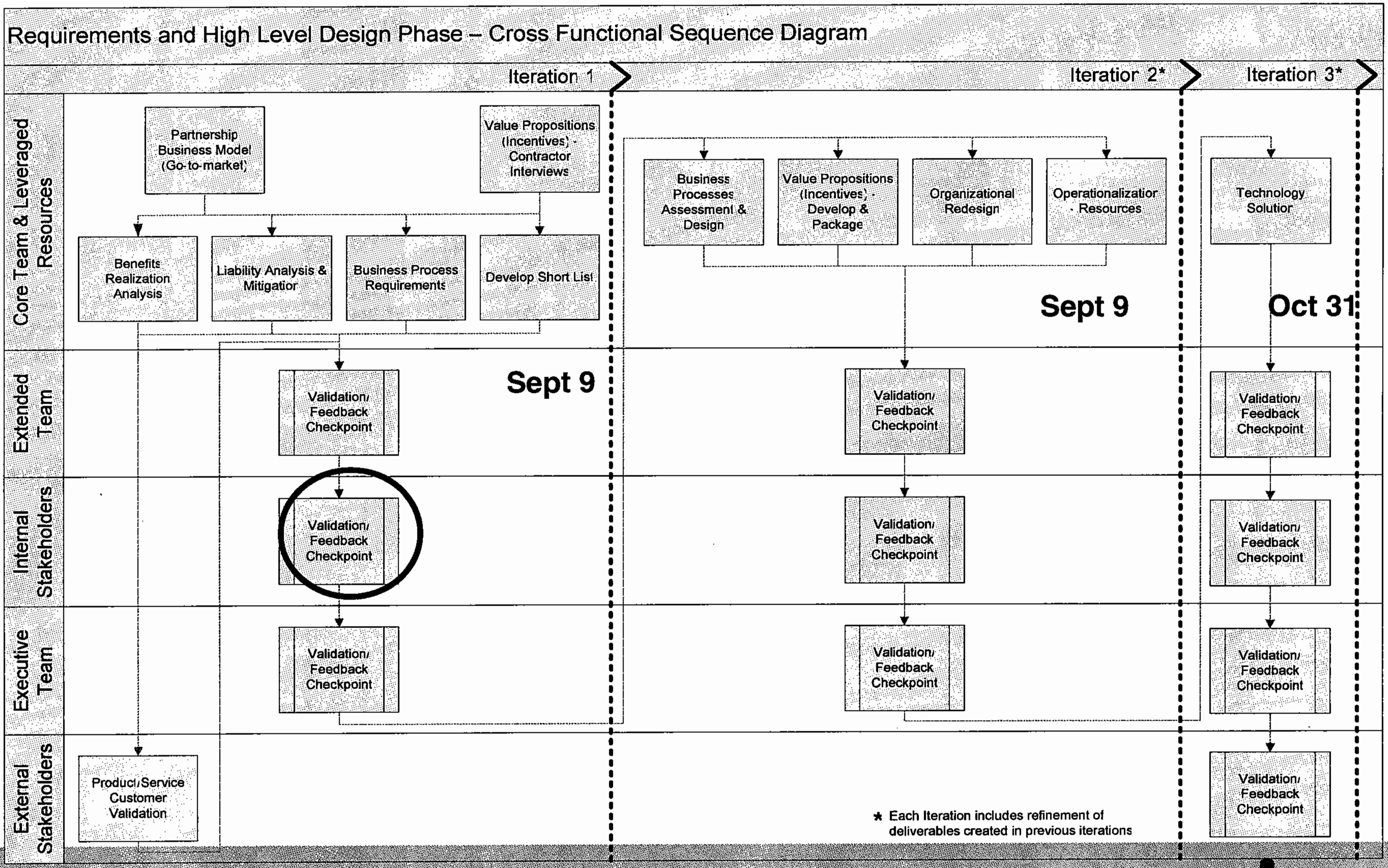
- We will provide mass markets (residential and small commercial customers) a telephone and a web based referral and an installation quote service for third party energy solution providers (includes sales and installation of natural gas appliances and related HVAC products and services).
- We will provide contractors a telephone and potentially a web based support system for the mass market referral service.
- We will scope, design and implement supporting management processes and technologies to support the overall initiative.

Program Overview: Approach – Phases

» Divided into 3 phases for targeted completion summer 2006

1. **Requirements & High Level Design**
   - Iteration 1 - targeting completion Sept 9
   - Iteration 2 - targeting completion Sept 30
   - Iteration 3 - targeting completion Oct 31
2. **Detailed Design & Implementation**
   - Planning underway;
   - Target completion Jan ’06
3. **Implementation**
   - Technology development,
   - Business Process Change implementation
   - Operationalization

Program Overview: Approach
Requirements & High Level Design Phase



* Each Iteration includes refinement of deliverables created in previous iterations

Product Service Customer Validation

- » 10% of customers to buy NG appliances next year
  - Furnace, stove, BBQ, dryer, fireplace get most mentions
- » 15% of customers would look to purchase from EGD
  - 3rd highest ranking after Sears/Home Depot, <u>no</u> mention of DE
  - Cost, service quality, reputation of brand most important
- » 14% customers very interested in on-bill financing
  - Furnace, WH, Range, BBQ and lifestyle products most mentions
  - Interest rates, cost/savings/discounts key motivators

Product Service Customer Validation

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- Customers are more interest rate sensitive than in past
  - Threshold level is below 20% (and closer to 15%)
- 37% of customers would use an on-line NG appliance catalogue if offered through an Enbridge portal
- 7% would buy appliances on line
- 20% of customers would select a contractor on-line

Business Models and Short Listing

- » 10 original models were considered
- » These were synthesized into 1 model by combining the best features to meet the needs of contractors, customers and EGD

Business Model - Description

- An HVAC channel model providing pre-qualified members exclusive access to a defined set of Enbridge value propositions.
- Offers include sales promotions and incentives designed to drive add load, customer additions, new revenues for Enbridge and DSM.
- Included for discussion today:
  - Membership
  - Contractual Requirements
  - Distribution of Benefits
  - Operational Considerations
  - Benefits
  - Risks
  - Issues

Business Model

» Membership:

- Development Phase
  - Open to all those HVAC contractors that meet specified criteria
  - Enbridge reserves the right to limit participation based on regional workforce management requirements
  - Initial sign up through “expression of interest” being considered

- Criteria for selection may include:
  - Licensing, registrations, insurance, and demonstration of overall business health.
  - Criteria for membership will be applied globally, regardless of region.

- Ongoing membership will require adherence to specific defined criteria:
  - code of conduct
  - performance to defined standards, including customer relations & complaints handling,
  - any required participation in sales promotions/programs
  - required participation in training programs

Business Model (cont’d)

»Contractual Requirements:

- The agreement will:
  - Be a standard agreement applied to all qualified HVAC contractor members
  - Allow for performance based allocation of benefits, including the development of a tiered relationship structure at some future date
  - Allow EGD or its representative to monitor and/or measure adherence to defined criteria
  - Clearly state that EGD is *not* in the HVAC business and specifically delineate that contractors are wholly responsible for service to the customer and any related issues, from mechanical to “mud on the floor”.
  - Specify that either party, at its discretion can terminate participation in the program .

Business Model (cont'd)

» Distribution of Benefits

- Development phase:
  - Leads will be allocated according to geographic location(s)
- Post development phase:
  - Leads allocated according to pre-defined performance criteria
  - E.G sales closing, timeliness of dealing with lead, customer satisfaction
- Value proposition benefits, such as leads, would be suspended for breach or lapse in qualification criteria until criteria are met once again.

Business Model cont'd

» Operational Considerations

- Assumes Sales Leads are managed in-house at EGD.
- Mass markets (Sales & Opportunity Development) will be responsible for:
  - design and implementation of selection criteria
  - process by which contractors are evaluated, selected, notified and signed on to the standard agreement
  - detailed program design and implementation
- Ongoing monitoring of terms and conditions of membership conducted.

Business Model - Operational Considerations cont'd

- Sales & SPIF Tracking & Accounts Payables:
  - Possible options for sales and accounts payable tracking and reporting
    - Coded program spif/coupons
    - Partnering with manufacturers/suppliers who could supply sales information
    - SPIF payment will be upon sales validation (e.g. invoice) and paid in accordance with our terms

Business Model – Operational Considerations cont'd

- Leads Management & Reporting:
  - EGD pre-qualification of leads
  - Contractors must respond to lead within defined period of time
  - Leads status reporting required from SCCP members

Business Model – Operational Considerations cont'd

- Customer Relations:
  - Contractor performance standards promoted to customers
  - Contractors portrayed:
    - Independent
    - Non-affiliated businesses
    - Adhering to defined standards and qualifications
  - Customers to complete their own due diligence
  - Customer complaints:
    - Directed to the contractor
    - EGD will intervene if no resolution
    - EGD tracks complaints & contractor efforts to resolve
  - SCCP referrals and all documentation referencing this program will carry a disclaimer

Business Model (cont'd)

» Benefits

- Potential to ensure a level of quality and performance for customers
- A single standard contract streamlines the administrative process of signing up partners
- Qualified HVAC contractors can participate
- Development period to fine tune program and thereafter allocate benefits based on performance.

Business Model (cont’d)

» Risks

- **Contractor Participation:**
  - Will value propositions attract enough or the right contractors to the program?
  - Administration of agreements cumbersome and costly for Enbridge (management, time and resources)
  - Increased potential liability for EGD in providing customers with contractor referrals.
  - Push back by non participating/non-qualifying HVAC contractors
- **Contract Development:**
  - Difficult to develop agreements such that customers, SCCP members and Enbridge expectations are met
  - Customized contracts like required by some will add complexity to the initiative and jeopardize member equality

Business Model (cont’d)

» Issues

- Budget limitations
- EGD as ‘watch dog’
- Administrative resource requirements for development phase and ongoing program support
- Defensible criteria for participation

Value Propositions

»Value Proposition List

- A - Leads referrals
- B - Contractor Portal
- C - Financing
- D – Training
- E - Co-op advertising programs
- F - Exclusive sales promotions and marketing initiatives
- G - Market intelligence sharing

Value Proposition A – Leads Referral

» A – Leads Referral

- Sales leads distributed using pre-defined algorithms or automated engines
- Customers options for accessing a referral:
  - the web
  - a 1-800 number
- Customers provided three referrals matched to their geographic location and service needs

Value Proposition B - Contractor Portal

ENBRIDGE

» B – Contractor Portal

- Management and reporting tools for contractors:
  - Vehicle to maintain and update contractor information
  - Contractors required to complete regular updates
  - Receive electronic reminders

- Respond to customer requests online

- On line access to specific promotions and incentives and method for submitting for processing by EGD

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Value Proposition C - Financing Option

» C – Financing Option

- Provides fee-for-service financing option for customers that is reasonably priced & convenient for customers
- Enbridge financing is open only to Enbridge partners (SCCP & SRCP)
- Primarily for the purchase of natural gas appliances, but combo appliance projects are eligible (e.g. furnace & air conditioner)

Value Proposition C - Financing Option

- Initial phase (until 2008) recommending launch of an Enbridge branded financing plan
    - Customer receives an Enbridge merchandise bill, administered by the third party financing company
    - Separate Enbridge gas bill also sent
    - Advantage: low up-front cost; does not require changes to CIS
    - Disadvantage: contractors want access to on-bill financing to create level playing field with DEEHS

- Implement on-bill financing with new CIS (2008)
    - Financing directly on the gas bill
    - Phasing in with new CIS reduces risk and cost of the project

- Business case being developed for Enbridge

Value Proposition D - Training

» D – Training

- Facilitated courses and business support tools for our SCCP members

- Potential courses including:
  - General business
  - Product Knowledge and/or Facilitated Manufacturer Sessions
  - Government & Utility Programs & Offers
  - Marketplace Knowledge

Value Proposition E & F – Co-op Advertising & Exclusive Sales Campaigns

» E – Co-op Advertising Program

- Co-op support to members for promotional initiatives
- Support subject to EGD annual budget and business planning
- Potential use of an affiliation symbol, but not the Enbridge logo

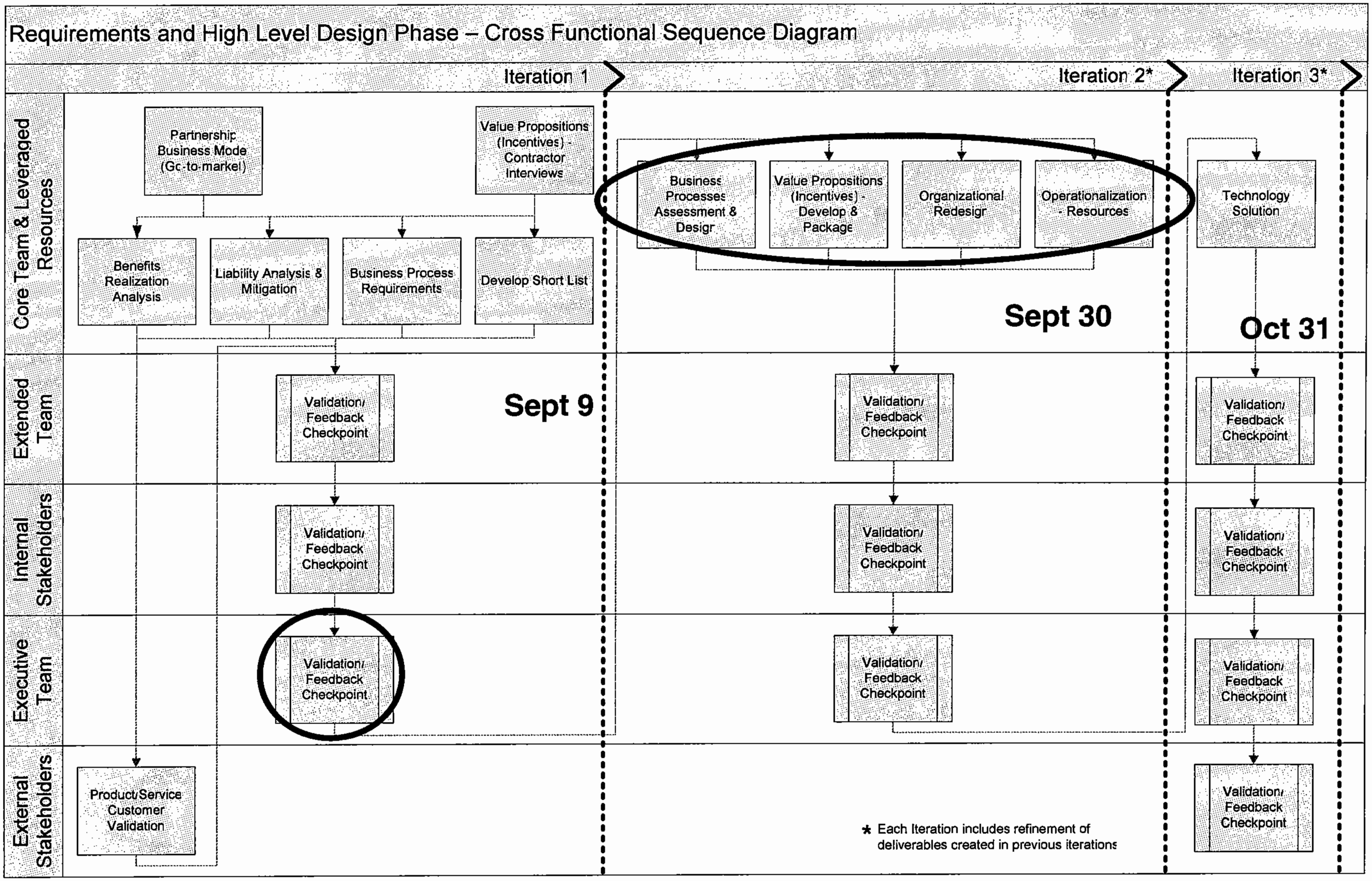
» F – Exclusive Sales Campaigns and SPIFS (Sales Promotion Incentive Fund)

Value Proposition G – Market Intelligence

» G– Market Intelligence Sharing

- Research and data analysis for members
- Information provided in aggregate and will comply with PIPEDA (Privacy Act)

Next Steps



Requirements and High Level Design Phase – Cross Functional Sequence Diagram

* Each Iteration includes refinement of deliverables created in previous iterations

Business Processes

» Membership

- Sign up
- Termination
- Contact information updates
- Access to secured portal
- Dispute resolution

Business Processes

» Contractual Requirements

- Performance Management and Review
- Quality assurance and compliance audit
- On-going management of membership

Business Processes

»Leads Management

- Issuing of leads through various channels
- Re-issuing of leads through various channels
- Customer requests On-line referral/quote from the portal
- Lead status reporting

Business Processes

» Customer Relations

- Managing customer complaints through various channels
- Dispute resolution

Business Processes

» Marketing & Sales Initiatives

- Electronic communication of campaign information
- Delivery of sales campaign material to SCCP partners
- Rebate processing
- SPIF remittance
- Request for co-op advertising support
- Approval for co-op advertising
- Tracking and measuring co-op advertising programs

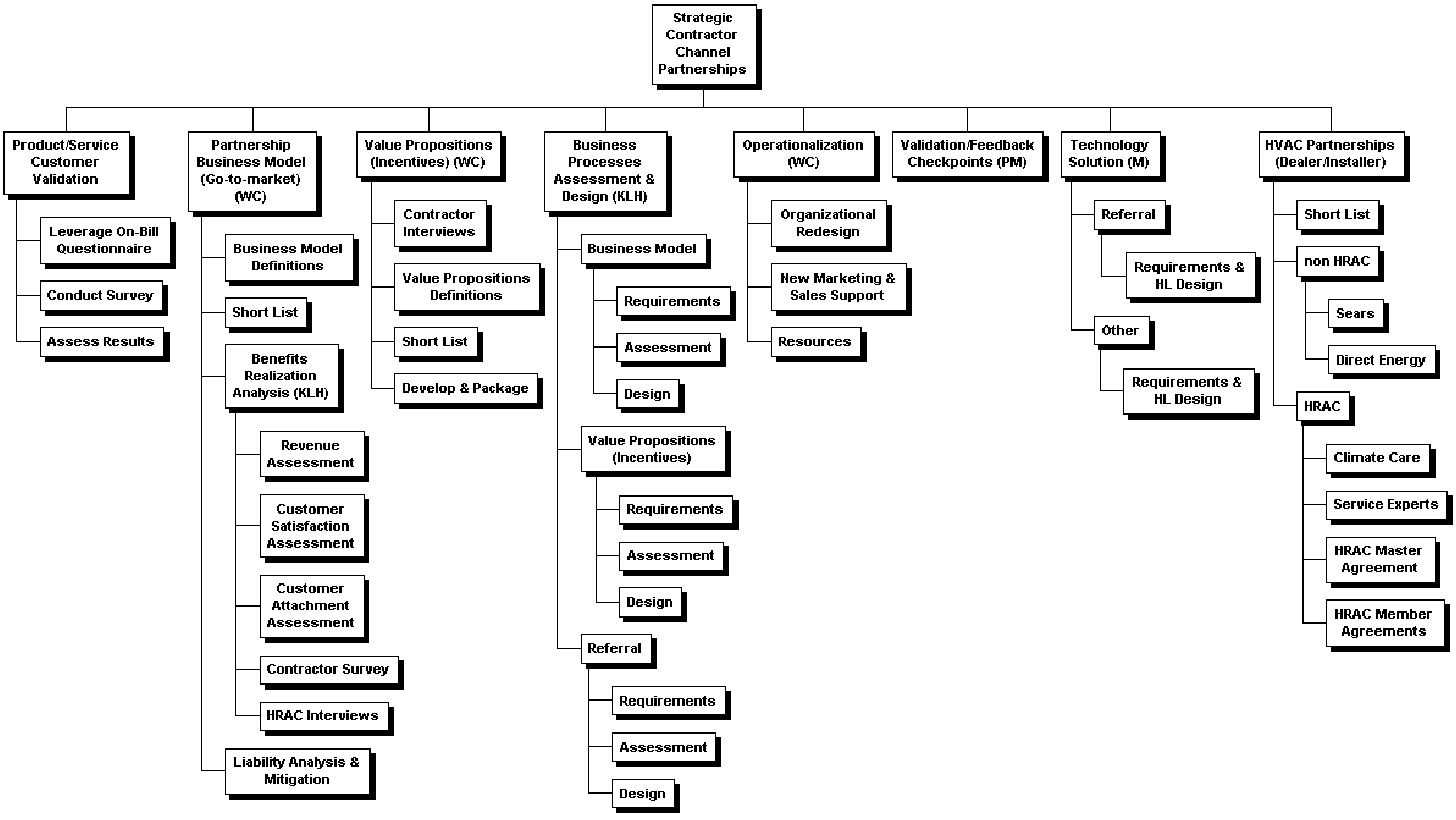
Next Steps

- Key Messages for Executive Team?
- Furthering Business Process work
  - Subject Matter Experts (SME's) for business process that can work with us?
- Communication and Status Reporting

Wrap-Up

- Parking Lot moved to Action Items?
- Issues and Action Items assigned and with due dates?
- Objectives met?
- Expectations met?

Program Overview: Scope – Deliverables



- Strategic Contractor Channel Partnerships
  - Product/Service Customer Validation
    - Leverage On-Bill Questionnaire
    - Conduct Survey
    - Assess Results
  - Partnership Business Model (Go-to-market) (WC)
    - Business Model Definitions
    - Short List
    - Benefits Realization Analysis (KLH)
      - Revenue Assessment
      - Customer Satisfaction Assessment
      - Customer Attachment Assessment
      - Contractor Survey
      - HRAC Interviews
    - Liability Analysis & Mitigation
  - Value Propositions (Incentives) (WC)
    - Contractor Interviews
    - Value Propositions Definitions
    - Short List
    - Develop & Package
  - Business Processes Assessment & Design (KLH)
    - Business Model
      - Requirements
      - Assessment
      - Design
    - Value Propositions (Incentives)
      - Requirements
      - Assessment
      - Design
    - Referral
      - Requirements
      - Assessment
      - Design
  - Operationalization (WC)
    - Organizational Redesign
    - New Marketing & Sales Support
    - Resources
  - Validation/Feedback Checkpoints (PM)
  - Technology Solution (M)
    - Referral
      - Requirements & HL Design
    - Other
      - Requirements & HL Design
  - HVAC Partnerships (Dealer/Installer)
    - Short List
    - non HRAC
      - Sears
      - Direct Energy
    - HRAC
      - Climate Care
      - Service Experts
      - HRAC Master Agreement
      - HRAC Member Agreements

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EB-2006-0034
Exhibit K11. 1
Page 1 of 1

TRANSCRIPT CLARIFICATION
DAY 9 - TR. 172 & 173

Counsel : Mr. Cass at Tr: 172 & 173 of Day 9

MR. KAISER: We will go to 4:30. Can I just follow up on Mr. Shepherd's point.
I am looking at the letter that you sent to Mr. Wetston, and you say:

> "The issue raised by HVAC has no bearing or material consequences on the establishment of rates for the 2007 test year."

Is that your position, Mr. Cass?
MR. CASS: Mr. Chair, I was not the author of this letter and I was not involved in any way with writing it. I would have to check with Mr. Hoey as to why he made that statement in the letter.
MR. KAISER: All right. If you could do that.
MR. CASS: Yes, sir.

ADDITIONAL RESPONSE

At the time of writing the letter, Mr. Hoey understood that the cost of the EnergyLink program was approximately $6 million of Capital and about $1.5 million of O&M, in total over a two year period. The purpose of the program was to provide a linkage between customers and service providers, encourage fuel switching and maintain fuel bias for natural gas. Therefore, the estimated revenue deficiency impact for the program was in the range of $1 - $2 million per year on a total distribution revenue of approximately $900 million or about 0.1% - 0.2%. If gas supply was included, it would be $1 - $2 million on $3 billion of total revenue which would be an even lower impact on a percentage basis. As well, based on the forecast for additional conversions in 2007, the revenue from the incremental attachments would reduce the impacts indicated above. Finally, if EnergyLink was not pursued, then it would be reasonable to expect that another fuel switching program would need to be established, so EnergyLink was not viewed as totally incremental. Therefore, in the worst case (that being no substitute program, no incremental sales and compared only on a distribution revenue basis) the rate impact was 0.2%, and perhaps even less than that.

Mr. Hoey never intended to imply that a significant amount of money would not be spent on EnergyLink - $6 million of capital and $1.5 million of O&M in total over a two year period is significant. But from a rate impact perspective, a rate impact of 0.2% or less would not be considered material especially since it appeared to be meeting customer needs.

Witness: P. Hoey

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EB-2006-0034
Exhibit K11. 2
Page 1 of 1

TRANSCRIPT CLARIFICATION
DAY 7 - TR. 93

Witness: Brad Boyle at Tr. 93 of Day 7

MR. SHEPHERD: What I'm wondering is this: The accounting depreciation is not deductible for tax purposes?

MR. BOYLE: In the income tax calculation; that's correct.

MR. SHEPHERD: Therefore to collect a dollar of extra accounting depreciation, assuming that the tax depreciation doesn't change, which it doesn't, doesn't that mean you have to gross up that dollar of accounting depreciation because it's going affect your taxable earnings?

MR. BOYLE: I don't think so, because -- I'm trying to work through an example. If I have $5 of depreciation expense in my regulatory calculations right now, and the UCC on that is whatever the UCC is, if I then deem my accounting expense to be $10, my UCC hasn't changed, presumably, because that is what it was. Therefore my pre-tax income changes by $5 and my after-tax income by 5 as well, so I just need a $5 adjustment.

MR. SHEPHERD: How does your after-tax income change in that circumstance if you're not changing the capital cost allowance?

MR. BOYLE: The $5 flows straight through.

MR. SHEPHERD: You have increased your revenue, but you haven't increased your taxable deductions; right?

MR. BOYLE: That's correct. That's why the $5 flows straight through, and to adjust for it, you just need to adjust $5 on a pre-tax basis.

ADDITIONAL RESPONSE

Mr. Boyle indicated that the change in depreciation expense would cause a 1:1 change in revenue requirement which is only correct if the CCA changes by the same amount as the depreciation change.

If the depreciation expense changes without a change in CCA, which was the situation posed by Mr. Shepherd at Tr. 92 and 93, the revenue requirement would change by the amount of the depreciation change divided by (1 minus the income tax rate). That is, the revenue requirement change would be greater than the change in depreciation expense in this scenario.

Exhibit 12.1

Recalculation of Beta Estimates from examination in chief of EGDI witness Dr. Carpenter (Transcript Volume 6, page 9)

	Dr. Carpenter[1]	Latest Actual	Weighted[1]
AGL Resources	0.95	0.375	0.791
Atmos Energy	0.8	0.437	0.812
Laclede	0.9	0.487	0.829
NJ Resources	0.0[2]	0.024	0.675
Northwest Natural	0.75	0.142	0.714
Piedmont	0.80	0.330	0.777
South Jersey	0.70	0.309	0.770
Southwest Gas	0.85	0.232	0.744
WGL	0.85	0.269	0.756
Average	0.733	0.289	0.763

1. Dr. Carpenter's beta estimates are from Value Line which takes 1/3 the actual estimate and adds this to 2/3 to get an adjusted beta. The latest actual betas (December 2006) are in the second column and if these are weighted in the Value Line way we get the third column. There is no evidence supporting this beta estimate. Gombola and Kahl show that betas should be weighted with their grand mean which is about 0.5-0.6.
2. This looks like a transcript error

Ontario Energy Board

FILE No. EB-2006-0034

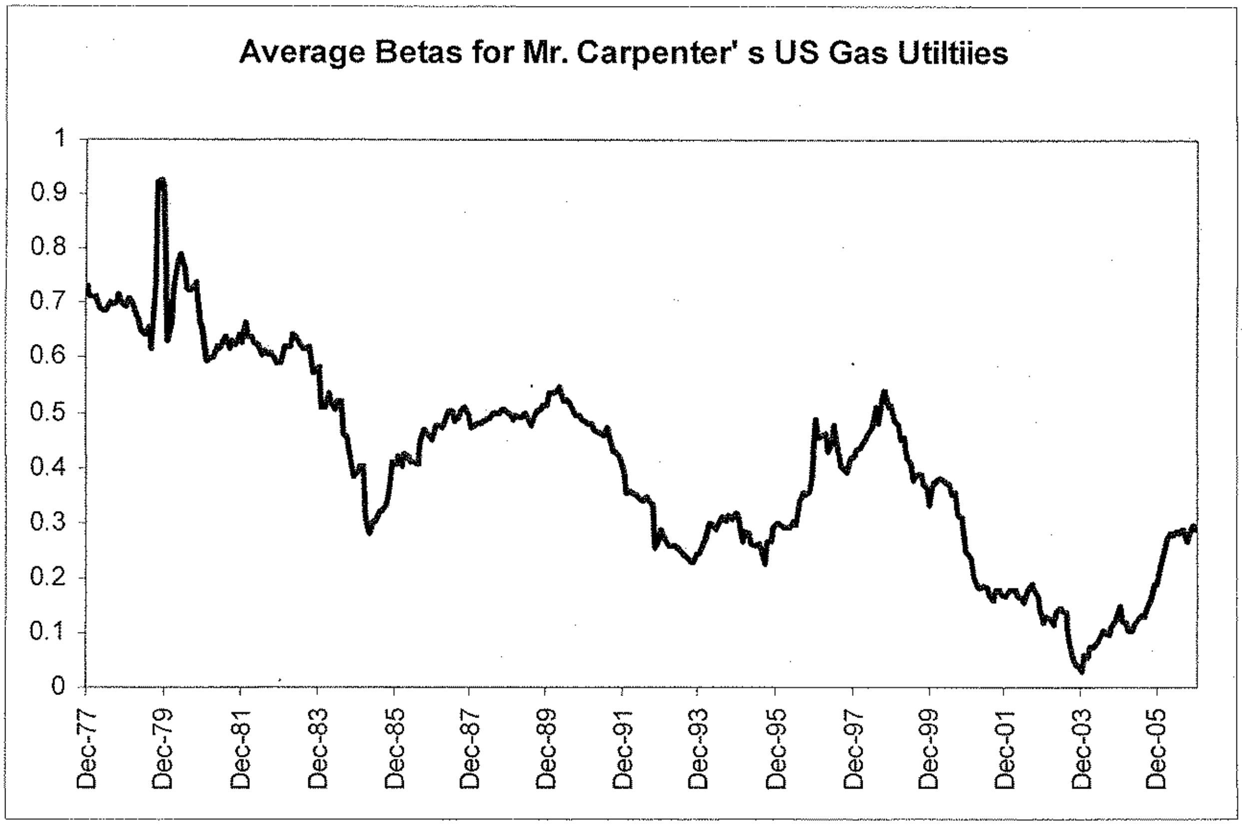
EXHIBIT No. K12.1

DATE February 20, 2007

08/99

Exhibit 12.2

Average actual Beta Estimates for the firms used in the examination in chief by EGDI witness Dr. Carpenter (Transcript Volume 6, page 9) back to 1973.



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DATE February 20, 2007.
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Ontario Energy Board
FILE No. EB-2006-0034
EXHIBIT No. K 12.3
DATE February 20, 2007
08/99

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ACADEMIC BACKGROUND:

D.B.A.,	Indiana University, (finance major).
M.B.A.,	Indiana University, (finance major).
M.A.,	Indiana University, (Economics).
B. Sc.(Econ),	London School of Economics.

AWARDS & HONOURS

MBA Second Year Instructor of the Year Award, 1996, 1998 (joint) & 2000
Best paper in corporate finance, 1999 SFA meetings
ASAC Distinguished Professor Address 1990,
Director Financial Management Association 1988-90,
English Speaking Union Fellow,
Fulbright,
Elected to Beta Gamma Sigma,
First class honours B.Sc.(Econ)
CBV (Chartered Business Valuator),
National Post Leader in Management Education Award 2003

ACADEMIC EMPLOYMENT: CIT Chair in Structured Finance (1999-), Professor of Finance, Rotman School of Management, University of Toronto (1987-Present), Visiting Professor Nankai University (China) 1989, the Czech Management Centre (1998), visiting scholar London School of Economics (1985).

TEACHING EXPERIENCE:

Graduate (MBA) courses on The Economics of Enterprise, the Economic Environment of Business, Business Finance, Corporate Financing, International Financial Management, Mergers & Acquisitions, Financial Management, Capital Markets & Corporate Financing (EMBA), Financial Theory of the Firm (Ph.D), Capital Markets Workshop (Ph.D). Undergraduate courses (B.Comm) in International Business and Business Finance. Executive courses (2-5 days) on Money and Foreign Exchange Markets, Business Valuation, Financial Strategy, Equity Markets, Capital Market Innovations, Mergers & Acquisitions and Finance for Non-Financial Managers.

JOURNAL ARTICLES

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"Capital Structure, Taxes and the Cost of Capital," Quarterly Review of Economics and Business, 20 (Autumn 1980,

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"Hedging and Foreign Exchange Exposure," Management International Review, (Spring 1982),

"Correct Procedures for Discounting Risky Cash Outflows," Journal of Financial and Quantitative Analysis, (June 1982),

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"Portfolio Composition and the CAPM," Journal of Economics and Business, (June 1983),

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Other civil cases include: prudent investments in a money market fund; the use of inverse floaters; the valuation of a brick company; the purchase of a private company by a Crown corporation; the liability of an investment dealer in a deficient private offering memorandum; the role of the Crown in managing moneys placed "in trust," the motivation for differential investment decisions, the materiality of press releases and the role of event clauses in contracting.

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SERVICE:

Executive Committee member 1980-2, 1989-90, 1993-4, 2001-3
Finance Area Co-ordinator 1987-91, 1994-
External Advisory Board, Health Administration Faculty, 1985-92.
Editorial Board Activities:
    Journal of Economics & Business 1982-87.
    Finance Section Editor, Canadian Journal of Administrative Sciences 1993-2005.

Journal of Multinational Financial Management 1989-.
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Director at large Multinational Finance Journal 1998-
Co-Chair 1991 Northern Finance Association meetings.
Chair 1998 Northern Finance Association meetings
Programme Committee member FMA meetings, October 1993.
Programme Committee member SFA meetings November 2002.
Programme Committee member, MFS meetings 2002-5
Programme Committee Member, Global Finance Conference, 2006.
Programme Committee Member, European Financial Management 2006.
Frequent media commentator.

November 2006.

EB-2006-0034

ONTARIO ENERGY BOARD

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 Enbridge Gas Distribution Inc. for an Order or Orders approving or fixing just and reasonable rates and other charges for the sale, distribution, transmission and storage of gas commencing January 1, 2007

BOOKLET OF MATERIALS FOR CROSS-EXAMINATION ON EQUITY THICKNESS

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TAB 1

BUSINESS RISK AND CAPITAL STUCTURE FOR THE TRANSCANADA MAINLINE

Evidence of

Laurence D. Booth

BEFORE THE

National Energy Board

October 19 2004

TABLE OF CONTENTS

EXECUTIVE SUMMARY

The Canadian Association of Petroleum Producers (CAPP) has asked me to provide an independent assessment of the appropriate common equity ratio for the TransCanada Mainline (the Mainline), to assess its business risk, and to discuss whether "leverage adjustments" are needed to the firm's common equity ratio to ensure that the Mainline's rates are fair and reasonable. This latter issue involves a discussion of the relevance of the weighted average cost of capital (WACC) and whether the appropriate common equity ratio can be considered separately from the allowed ROE, which is not itself a formal a part of this hearing.

My overall assessment is as follows:

- The short term business risk of the Mainline is very low. The Mainline continues to earn its allowed ROE with the same precision as previously and there is no indication that the impact of the Board's policy of allowing deferral accounts and a forward test year has exposed the Mainline's shareholder to any increase in risk.

- There has been a marginal increase in the longer term "supply" and "competitive" risks since the 1994 multi-pipeline hearing as the Western Canadian Sedimentary Basin (WCSB) has matured and Alliance has become operational. However, the exposure of the Mainline to this maturing of the WCSB has been offset by a significant increase in the allowed depreciation rate, so that the capital at risk has not been affected. Overall I see no change in the business risk of the Mainline since RH-4-2001.

- In RH-4-2001 Dr. Berkowitz and I recommended a 30% common equity ratio, up from the 28% recommended by us in RH-2-94. This increased common equity ratio recommendation in part reflected the retirement of the Mainline's preferred shares and their replacement with junior subordinated debentures *prior* to the RH-4-2001 hearing. Nothing has changed in this regard since then, when the Board correctly classified the JSDs as debt. I continue to view the JSDs as debt and do not think that it appropriate to impute a 30% common equity component to them.

- I would judge the Mainline to have a good investment grade bond rating with its current allowed ROE and common equity ratio. Over the last two years there has been concern expressed over "increasing" credit standards motivated by the introduction into Canada of S&P's US credit standards and their experience with US utilities and pipelines like Enron and Aquilla. However, there is no indication that the Canadian capital markets have reflected these US concerns. Spreads on utility and pipeline debt over the last five years have reflected normal cyclical concerns and do not indicate that the market has re-evaluated the regulatory protection accorded utility and pipeline debt.

- Overall conditions in the bond market indicate that spreads are tighter now than they were at the time of RH-4-2001, so that utilities can access debt markets more easily. Further the dramatic increase in the income trust market over the last five years has opened up another source of financing. In my judgment the Mainline has just as much, if not more, financial flexibility than at the time of RH-4-2001 and there is no need to make capital structure changes to improve its access to capital, particularly since the rate base is declining.

- My own judgement is that the Mainline's currently allowed ROE formula, combined with a 33% common equity ratio, is generous. However, like the Board I believe that common equity ratios should only be revisited after a fundamental shift in business risk and I see no signs of such a shift in the last three years. I therefore would recommend that the Board continue with its current allowed common equity ratio.

- In terms of the ATWACC approach advocated and used implicitly in the company's filed testimony I would point out the fundamental contradiction in its use in regulatory filings in that it is the mirror image of shareholder value maximisation. That is, earning more than the WACC is synonymous with the creation of shareholder value, whereas the Board's responsibility is not to create or maintain shareholder value, but to ensure that rates are fair and reasonable. The Alberta EUB felt it would be "derelict" in its responsibilities to recognise market

> "The Board concludes that there is no basis on which to place any weight, other than already reflected in earlier tests, on other specific investment opportunities potentially available to utility investors or on stated expectations of return from such opportunities."

I agree with this judgment for theoretical, as well as practical reasons, which I develop later. In conclusion the Board went on (page30)

"In consideration of the impact of the above factors, it is the judgment of the Board that it would be appropriate to establish the 2004 ROE at a level that is 40 basis points above the Board's CAPM estimate. Therefore, the Board concludes the generic ROE for 2004 should be set at 9.60%."

However, what is important to note is that the EUB's estimate of the investor's required rate of return was 8.70%, their CAPM estimate before adding 0.50% for flotation costs, and before taking into account other factors. This is the investors discount rate applied to valuing a typical utility's shares. Overall it is my judgment that application of the Board formula generates an allowed ROE that continues to be generous and is above the cost of equity capital for Mainline transmission assets.

Q. WHY HAVE YOU DISCUSSED THE ROE WHEN IT IS NOT AN ISSUE IN THIS HEARING?

A. Dr. Vilbert on behalf of the Mainline has filed 285 pages of rate of return testimony. I have the same concerns with this testimony as I had when similar evidence was filed in RH-4-2001. Further this evidence is used to support the estimates of Dr. Kolbe and Vilbert as to the appropriate ATWACC or WACC for the Mainline. The main new twist is that instead of recommending an allowed ROE and equity ratio based on this testimony, with a fixed allowed ROE the full impact is now felt on the deemed common equity ratio recommendation alone. However, the testimony of Drs. Kolbe and Vilbert remains firmly rooted in ROE testimony. Consequently all the estimation problems that Dr. Berkowitz and I had with this testimony in RH-4-2001 continue today, particularly since some of Dr. Vilbert's beta estimates are based on estimates as of May 2000 and do not seem to have been updated since RH-4-2001 anyway.

Consequently, the reason that I have provided this very brief background on capital market conditions and recent Board decisions is simply to point out that relatively little has changed since the time of RH-4-2001. Further, were I to provide ROE estimates for the Mainline today, my judgment would be that the cost of capital estimates used by Drs. Kolbe and Vilbert, as the base for their deemed common equity ratio recommendation, continue to be significantly higher than those I would arrive at.

Q. IF YOU DO NOT AGREE WITH THE APPROACH OF DRS. KOLBE AND VILBERT, HOW DO YOU RECOMMEND THE BOARD SET COMMON EQUITY RATIOS?

A. I would recommend that the Board continue to use its existing policy. In RH-2-94 the Board stated (Decision page 24)

> "The Board is of the view that the determination of a pipeline's capital structure starts with an analysis of its business risk. This approach takes root in financial theory and has been supported by the expert witnesses in this hearing. Other factors such as financing requirements, the pipeline's size and its ability to access various financial markets are also given some weight in order to portray, as accurately as possible, a complete picture of the risks facing a pipeline "

I agree 100% with this assessment, since it follows the prior discussion of the impact of financial leverage. To repeat the previous financial leverage equation

$$ROE = ROI + [ROI - R_d(1-T)]\frac{D}{S} \qquad (2)$$

If this equation is rearranged we can express the variability of the ROE as a function of the variability in the operating income or

$$STDEV(ROE) = STDEV(ROI) * (1 + \frac{D}{S}) \qquad (3)$$

where the standard deviation of the actual ROE is that on the ROI times one plus the debt equity ratio. So if the Board wants to equalise the risk to equity holders (*STDEV(ROE)*) investing in different pipelines with different business risk ((*STDEV(ROI)*) in principle it can alter the deemed debt equity ratio.

At this point it is important to point out that the above equation is based on the firm's financial statements. It is an accounting relationship that has *nothing* to do with how the stock market reacts to the firm's use of financial leverage. As far as I know no-one has ever disputed the above equations, as they are simply a rearrangement of the flow of income through a firm's financial statements. That is, the ROE is *not* that required by investors (the cost of equity capital) it is simply the actual ROE earned by the firm on the book value of its equity. Using these relationships is consistent with the fact that the Board can only control these accounting values. The Board can alter business risk through the use of deferral accounts and the financial risk through changes in the deemed equity ratio, but it can not change stock market risk, as the market, not the Board, determines market values.

This last point should be emphasised: the financial leverage equation is *not* equivalent to the formulae used by Dr. Kolbe. Dr. Kolbe's equity cost adjustment formulae are based on *assumptions* about how the stock market values the use of financial leverage. All of the work of Drs. Kolbe and Vilbert is based on market values and their equations are based on assumptions about how the stock market values the effects of financial leverage. Unlike the financial leverage equation which indicates how the Board can alter financial risk to offset business risk, the equations used by Dr. Kolbe attempt to answer the question of how the rate of return required by an investor changes as the financial leverage based on *market* values changes. This adjustment *requires* a theory of how the market values financial leverage, which is *not* required for the Board to change deemed equity ratios in response to changes in business risk.

To illustrate in RH-2-94 several experts submitted testimony on how the allowed ROE should change as the capital structure changes along the lines of the current testimony of Drs. Kolbe and Vilbert. Dr. Sherwin and Ms. McShane, who provided testimony on behalf of the companies, concluded (page 24)

> "The finance models, even when adapted to the real world of Canadian utility regulation, cannot provide the basis for determining a pipeline's optimal capital structure."

More importantly Dr. Berkowitz and I used models similar to those used by Dr. Kolbe, but expressed little support for them. As the Board noted in its Reasons for Decision (page 24)

> "Dr. Booth and Berkowitz concluded that these estimates are approximately the increases in ROE required by investors. However, they noted the estimates are subject to error since they are based on valuation formulas, which are as yet unproven. Moreover, they

> noted that these formulas ignored the non-tax advantages of debt financing and the effects of financial distress."

Finally, the Board also noted Dr. Waters' testimony (a frequent witness before the Board at that time) where he indicated that "To date empirical testing to more clearly describe the relationship (between capital structure and the investors required return) has not been done successfully.

The Board's summary from ten years ago is an accurate assessment of my views today and it is my judgment that the misgivings expressed by experts ten years ago continue, since the issues have still not been resolved. I would therefore recommend that the Board continue its practise of making capital structure changes based on its qualitative assessment of a pipeline's business risk.

Q. IS BUSINESS RISK THE ONLY FACTOR IN SETTING CAPITAL STRUCTURES?

A. No. Ultimately the litmus test of whether the Board has "got it right" is whether the pipeline can access capital on reasonable terms. If, for example, the Board has not sufficiently increased the common equity ratio in response to an increase in business risk then the stock market will discount the pipeline's stock price and make it difficult for the regulated firm to access capital on reasonable terms. In *Federal Power Commission et al v. Hope Natural Gas Co.* [320 US 591, 1944], the United States Supreme Court decided that a fair return

> "should be sufficient to assure confidence in the financial integrity of the enterprise so as to maintain its credit and to attract capital."

Although the Hope "financial integrity" criteria flows from considering a fair return it applies equally to the deemed common equity ratio. In my judgment an appropriate common equity ratio is one which, in conjunction with the allowed return, allows a pipeline to maintain its credit and attract capital.

The Hope criterion would therefore support the view that after examining business risk, the Board consider factors such as size, financing requirements and market access, since all of these are important for financial integrity. However, note that "maintaining credit" is not the same as maintaining a particular credit rating. Credit standards constantly change as does the market's appetite for certain types of credits. This means that there is no need to target a particular credit rating. What is important is that a pipeline can access the capital markets with conventional financial securities when it needs to raise capital to provide service.

Q. IS THERE ANY OTHER RECENT DECISION THAT SUPPORTS THE BOARD'S VIEW?

A. Yes, the recent Alberta Generic Hearing followed in the wake of the Board's policy expressed in RH-2-94 and established not just an adjustment formula to set the allowed ROE, but also the allowed common equity ratios for eleven distinct regulated entities in a range of ROE regulated businesses including pipelines (ATCO Pipe and NGTL). The EUB stated (Generic Cost of Capital Decision page 35)

> "To determine the appropriate equity ratio for each Applicant, the Board will consider the evidence and, where applicable, the experts' views and rationales in each of the following topic areas:
>
> 1. The business risk of each utility sector and Applicant;
> 2. The Board's last-approved equity ratio for each Applicant (where applicable);
> 3. Comparable awards by regulators in other jurisdictions;
> 4. Interest coverage ratio analysis; and
> 5. Bond rating analysis."

This approach of the EUB seems to be substantially the same as the traditional approach used by this Board. I, therefore, first look at the business risk of the Mainline and then consider financial market access and the EUB's points 2-5.

3.0 BUSINESS RISK

Q. HOW DO YOU VIEW THE BUSINESS RISK OF A PIPELINE UNDER THE BOARD'S JURISDICTION

A. In the discussion of risk in Section 2 I pointed out that income risk to the investor is a function of business risk and financial risk. However, I then clarified that financial risk has been set by this Board to modify the underlying business risk of a pipeline. In this sense financial risk is a tool used by the Board. However, the Board has other tools in addition to simply setting the deemed equity ratio and allowed ROE. In fact the whole regulatory process changes the risk of investing in regulated industries, to the extent that when finance researchers try to model what determines capital structures they frequently either exclude regulated industries completely or add a "dummy" (zero vs one) variable for a regulated firm, simply because the act of regulation itself explains more than can be explained by independent variables such as revenue variability.[9]

Q. WHAT OTHER TOOLS HAS THE BOARD USED?

A. Of the gas transmission pipelines there is the basic distinction between the forward test year pipelines like the Mainline and TQM and the full cost of service pipelines like Foothills and the TCPL BC System (the former ANG now the "BC System"). Full cost of service utilities have their revenue requirement recovered from a limited number of customers and can true up actual costs with revenues, so that they exactly earn their allowed ROE. This is the case for Foothills and the BC System where both can exactly earn their allowed ROE, to the extent that in surveillance reports to the Board they sometimes do not break out actual from allowed ROE, since they are the same number! In the RH-2-94 hearing Dr. Berkowitz and I recommended a 25% deemed equity ratio for the full cost of service pipelines due to the absence of any income risk. We made the same recommendation for TQM since its costs were recovered through the Mainline. At the time TQM had a 25 % common equity ratio, ANG 28% and Foothills 30%.

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[9] The regulatory process determines the revenue requirement, so that variability in revenues caused by a changing allowed ROE, for example, is not a risk factor in the way it would be for a competitive firm.

Compared to full cost of service regulation, the Mainline recovers its revenue requirement from a larger number of shippers, so in practise rates are not trued up on a frequent basis. The regulatory response to this has been to allow deferral accounts where any revenue deviations can be captured in a temporary account with the balance allocated to future cost of service. Revenues are then set based on forecast costs over the test period together with the disposition of the balances in deferral accounts. In this way any unexpected revenue losses due to contract non-renewals etc are recovered in a future test year and the costs are borne not by the equity holders, but by future customers in the same way as for full cost of service regulation. However, since deferral accounts are not allowed for all items, for example O&M costs, the shareholders are liable for some forecasting risks with forward test year utilities that they are not with full cost of service regulation.

In RH-2-94 Dr. Berkowitz and I filed Schedule 1 as Schedule 19 to our part B testimony. Schedule 1 reports the actual versus allowed ROE for the major pipelines in Canada from 1989-1993. Of note is that the two full cost of service pipelines (Foothills and ANG) exactly earned their allowed ROE each year from 1989-1993. In contrast TQM, Westcoast (WEI) and the Mainline (TCPL) over earned their allowed ROE in each year. It is difficult to see how over earning the allowed ROE can be classified as "more risky," but other forward test year pipelines such as the two oil pipelines, Interprovincial (IPL now Enbridge) and Transmountain (TMP now part of Terasen), did fail to earn their allowed return in some years. On this basis Dr. Berkowitz and I recommended 28% common equity for the Mainline and 30% for Westcoast. The Board actually set all of these pipelines on a 30% common equity basis for their mainline gas transmission operations. Further the Board stated (Reasons for Decision page 25)

> "With regard to the argument that regulation shields pipelines from risk, the Board believes that its regulation provides pipelines with a degree of assurance of cost recovery which is absent for non-regulated industrials. However, the Board believes that the realities of market forces cannot be discounted when addressing pipelines' business risks."

My interpretation of the Board's decision is that they accept that regulation lowers pipeline risk but that it may not be able to shield them completely from market forces.

Q. WHAT HAS CHANGED SINCE RH-2-94?

A. In terms of the ability of the Mainline to earn its allowed ROE, very little. In Schedule 2 is data on the earned vs actual ROEs for the major gas transmission pipelines since 1990. Note that Foothills continues to be a full cost of service pipeline and exactly earns its allowed ROE.[10] Similarly despite the changing supply position in the WCSB and the introduction of Alliance, the TCPL Mainline continues to over earn its allowed ROE, in fact it has never earned less than its allowed ROE except in 1994 when the NEB disallowed some costs related to fuel imbalances.[11] Based on the objective data of whether risk has changed, there is no indication of any change in the ability of the Mainline to earn its allowed ROE since RH-2-94.

In Schedule 3 is the same earned vs allowed ROE for the two premier gas local distribution companies in Canada and NGTL (NOVA at the time of RH-2-94). The data for the two Ontario Gas LDCs is based on weather normalised ROE's since these utilities are not allowed deferral accounts for variances due to weather. Further the NGTL data is not strictly comparable since for a significant amount of time NGTL operated under incentive regulation and the early data conflicts with that reported by CBRS in 1994. However, the message is very similar regulated utilities on a forward test year consistently over earn their allowed ROE's. In practical terms there is very little risk involved in operating an ROE regulated utility in Canada.

Given the very low, if not non-existent, income risk, ROE regulated utilities in Canada have the very stable ROI necessary to support large amounts of tax efficient debt financing.[12] Traditionally I have always recommended higher common equity ratios for gas LDCs in Canada

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[10] My understanding is that the BC System's deviation from allowed in 2001 was part of the agreement on the change of control of ANG. In CAPP 31(a) no explanation was provided for the BC System's results in 2003.

[11] See answer to CAPP 82(b).

[12] Interest on debt is tax deductible at the corporate level and only taxed once, whereas income earned by equity investors is double taxed. To compare the cost of equity and debt returns we have to put them on the same tax basis and compare the pre-tax ROE with the corporate interest rate. In this case a 3% spread between a 9% allowed ROE and a 6% interest cost, at a 40% tax rate translates into a pre-tax cost of 15% for equity (9%/(1-.4) versus 6% for debt. So that the spread on a same tax basis is 9%.

simply because they are subject to weather variation risk, which can, and sometimes does, affect their coverage ratios and access to financial markets.[13] For this reason I continue to recommend that gas LDCs have the 35% allowed common equity ratios of the two Ontario gas LDCs. If this weather risk is removed, as it has been for Terasen Gas (formerly BC Gas), then they can finance with the 33% common equity that the BCUC allows Terasen. Finally Westcoast has recently agreed to a 31% common equity ratio, up from the 30% awarded (mainline transmission pipeline) previously. This is a small 1% increase since 1994 for a pipeline, like the Mainline, that is also tied into the WCSB.

In my judgment the TransCanada Mainline has lower risk than the Ontario gas LDCs because the LDCs have fewer deferral accounts, the variation of their earned ROEs is greater and historically they have at times failed to earn their allowed ROEs. If the Terasen Gas allowed common equity ratio of 33% and the Ontario Gas LDCs allowed common equity ratios of 35% are seen as upper limits, it would indicate that the current allowed common equity ratio for the Mainline of 33% continues to be generous. Further I also see the Mainline as lower or at least similar risk to Westcoast, so that Westcoast's 31% common equity ratio is also a valid benchmark.

It is also interesting to contrast this performance of regulated assets with the utility holding companies (UHC) that actually face the market. For the major UHCs Schedule 4 gives their earned ROEs along with those of the TCPL Mainline and Foothills. For example, what investors invest in as "TransCanada" or TCPL is not the Mainline, but the combined entity including non-regulated and regulated assets. This can be seen in the greater variability of its ROE. For 1993-1997 TCPL consistently earned more than the Mainline, but then in 1998-2000 as TCPL reorganised it earned less than the Mainline. Throughout this period the Mainline has underpinned TCPL's results and been a beacon of stability. One way of assessing this greater risk is simply to estimate the standard deviation in each firm's ROE. For the TCPL Mainline this was 1.05%, whereas for TCPL itself it was 2.47%, so the Mainline's ROE was only 43% as variable as that for the whole company. However, as we have seen this variability in the Mainline's ROE is not "risk," since it largely reflects the fluctuation in the Mainline's allowed ROE.

---

[13] Most gas LDCs, unlike pipelines, have an interest coverage restriction in their bond indentures that requires them to have a 2.0X interest coverage before they can issue debentures.

needed. My view on this latter issue has been strengthened in part by the statements made by Board member Quarshie.

In a presentation to the PCRI, Board member Quarshie laid out the five goals of the NEB one of which is for "Canadians to derive the benefits of economic efficiency." Further Board member Quarshie stressed that "enabling implies a responsibility to ensure that projects in the public interest can proceed." I imagine that the opposite is also true: that it is not the goal of the Board to create economic inefficiency or proceed with projects that are not in the public interest. In this regard I would judge wasting scarce resources building pipeline facilities that are not needed as promoting economic inefficiency and it is hard to see how this can be in the public interest. I am therefore reinforced in my view that Alliance is not a "competitor" pipeline for the foreseeable future and not a significant risk factor for the market value of the current investment in the Mainline.

The foregoing comments are not meant to imply that the Mainline has no business risk. At the time of RH-2-94 Dr. Berkowitz and I laid great stress on the fact that the Mainline was operating at full capacity; that production from the WCSB was expanding and that there was shut in gas due to the shortage of takeaway capacity. Consequently without even considering the impact of regulation, the Mainline was very low risk. This situation has changed somewhat: the Mainline tolls are now higher than they would be if it were operating at 100% capacity, while there are stronger signals that the WCSB is maturing. However, a constant theme of the previous discussion is the regulatory dynamic. As the WCSB has matured the Board has revisited the Mainline's depreciation rate to adjust the risk of capital (non) recovery and asked to be kept updated. Similarly the Board has reviewed its ROE Formula. The fact is that investors in the Mainline do not face the hypothetical risk of investing in an unregulated Mainline. Investors face the risk of investing in the Mainline, given the policies of this Board. On this basis the risk is still very low.

Q. WHAT COMPARATORS WOULD USE FOR THE MAINLINE?

A. before the Alberta EUB last year I compared the different utilities in the Alberta generic hearing on the following basis:

The major short term risks caused by cost and revenue uncertainty:

- On the cost side since regulated utilities are capital intensive most of their costs are fixed. The major risks are in *operations and maintenance* expenditures. However, over runs are usually under the control of the regulated firm and can be time shifted between different test years.
- On the revenue side the risks largely stem from rate design, critical features are:
    - Who is the customer and what *credit risk* is involved. For example, electricity transmission operators who recover their revenue requirement in fixed monthly payments from the provincially appointed TA, who is responsible for system integrity, have less exposure than the local gas and electricity distributors who recover their revenue requirement from a more varied customer mix involving industrial, commercial and retail customers.
    - Is there a *commodity charge* involved? The basic distribution function is very similar to transmission, except when the distributor buys the gas or electricity wholesale and then also retails the commodity. The distributor is then exposed to weather and price fluctuations depending on rate design.
    - Even if there is no commodity charge, how much of the revenue is recovered in a *fixed versus a variable usage* charge? Utilities that recover their revenue in a fixed demand charge face less risk than those where the revenues have a variable component based on usage.

The medium and long term risks are mainly as follows:

- *Bypass risk.* The economics of regulated industries are as natural monopolists involved in "transportation" of one kind or another. However, one utility may not own all the transportation system so that it may be economically feasible to bypass one part of the system. This happens for local gas distributors, when a customer can access the main gas transmission line directly, rather than through the LDC, or when a large customer may be able to bypass part of the transmission system. This is often a rate design issue: a postage stamp toll clearly leads to uneconomic tolls and potential bypass problems, whereas distance or usage sensitive tolls will discourage it. Similarly, rolled in tolling will encourage predatory pricing by potential regulated competitors.
- *Capital recovery* risk. Since most utilities are transportation utilities, the critical question is the underlying supply and demand of the commodity. If supply or demand does not materialise then tolls may have to rise and the utility may not be able to recover the cost of its capital assets. Depreciation rates are set to mitigate this risk to ensure that the future revenues are matched with the future costs of the system.

A common thread running through the above brief discussion of utility risks is rate design and regulatory protection. There can be significant differences in underlying business risk that are moderated by the regulator in response to those differences. The lowest risk utility is then one with the strongest underlying fundamentals and the least need to resort to regulatory protection. In contrast, another utility may have similar short term income risk, but only because of its need to resort to more extensive regulatory protection, so that it faces more problematic longer term risks.

On this basis I judged the lowest risk regulated utilities in Canada to be electricity transmission assets, since these have the following characteristics:

- Minimal forecasting risks attached to O&M
- Revenue recovery via the TA through fixed monthly charges
- Limited (non existent) by-pass problems
- Minimal capital recovery problems, since there are many suppliers of electricity as a basic commodity.
- Deferral account for capital expenditures

and recommended 30% common equity ratios.

I then placed the gas transmission pipelines as the second lowest risk group. Here I classified Foothills and the TCPL BC System (formerly ANG) as of equivalent risk to electricity transmission assets with NGTL having marginally more risk than Foothills and the TCPL BC System, since it is exposed to bypass and recovers its revenues through a forward test year from a greater variety of shippers. However, the combination of distance sensitive tolls, the ability to offer load retention service and a more rapid depreciation rate significantly reduce any increase in risk NGTL may have faced since 1995. I therefore judged that on its own NGTL could maintain its financial flexibility on the same 30% common equity ratio allowed mainline gas transmission assets. However, because NGTL was then allowed 32% and was almost "indistinguishable" from the TCPL Mainline, I recommended the same 33% common equity ratio that this Board currently allows the Mainline.

I then judged the local distribution companies (LDCs), including both gas and electric as the next riskiest. These companies are distinguished by their retail operations, which mean that their revenues are recovered from a large number of industrial, commercial and residential consumers. This exposes them to both the business cycle and weather fluctuations. This revenue recovery is also a function of their rate design that may expose them to commodity charges and a fixed and variable recovery charge. Within this group the conventional yardstick for LDCs is that Consumers (Enbridge Gas Distribution Inc or EGDI) and Union Gas are both allowed 35% common equity by the Ontario Energy Board. However, whereas the Ontario Energy Board allows a purchased gas variance account (PGVA) to ensure that the full costs of gas are recovered, they are still subject to volume related variances. In contrast, the BCUC allows BC Gas (Teresen Gas) a more comprehensive deferral account, but limits the allowed common equity ratio to 33%. With these yardsticks I recommended 35% common equity ratio for a typical local distribution companies.

Finally, I recommended 42% as the upper end of a reasonable range for the common equity of ATCO pipelines, given that the BCUC allows PNG, a smaller and much riskier pipeline, 36% common equity. However, this ranking was provisional being dependent on the EUB developing clear rules on intra Alberta pipeline competition and a rate design that lowers ATCO Pipeline's risk. It was, and remains, my judgement that none of the Alberta utilities were as risky as Pacific Northern Gas (PNG) with a 36% common equity ratio or Gaz Metropolitain (GMI) with a 38.5% common equity ratio, where I continue to regard these two as the riskiest regulated utilities in Canada.

On this basis I continue to believe that the Mainline deserves a 30% common equity ratio based on its underlying business risk. At the very least I see nothing to indicate any changes since the RH-4-2001 decision that increased the allowed common equity ratio from 30% to 33%. In fact, as I pointed out early the change in depreciation rates resulting from RH-1-2002 has reduced the Mainline's exposure to these longer term risks. Given that I support the Board's view that capital changes should be made only rarely in response to significant changes in business risk, I would recommend that the Mainline common equity ratio remain at 33%.

5.0 LEVERAGE ADJUSTMENTS

Q. WHAT IS THE BASIS FOR MAKING A LEVERAGE ADJUSTMENT?

A. One basic proposition in finance is that investors don't like risk, and as I showed in Section 2.0, increasing the amount of debt financing magnifies risk. Logically, therefore as firms finance with more debt they magnify business risk and investors respond to this increased risk by requiring a higher rate of return. This logic is unassailable and not in dispute. Therefore, if an expert estimated an equity cost from a sample of regulated firms and applied that estimate to a firm with the same business risk, but much higher financial risk as represented by the regulated or book debt equity ratio, then the estimated return would be below a fair return. For example, estimating a fair return from a sample of normal utilities that happened to have no debt at all and applying that to the Mainline with 67% debt would be patently unfair.

However, note two things. First of all leverage adjustments have nothing to do with ATWACC. Leverage adjustments are theoretically necessary in the normal estimation approach where the equity cost is estimated from a sample of firms and then a recommendation made for the firm in question. Drs. Kolbe and Vilbert could, for example, take their equity costs from their sample and make leverage adjustments without going through the trouble of estimating their ATWACC. Second, in the above example there is obviously a problem, since it is extremely difficult to find a sample of regulated firms with substantially different debt ratios in the first place. In reality most regulated firms in Canada have similar debt ratios, or their debt ratios have been specifically set, as is the practise of this Board, to offset differences in business risk.

To elaborate on this last point, as late as August 1997 in testimony before the CRTC Dr. Berkowitz and I were using two samples of regulated firms for estimating the fair return. The first sample consisted of six energy distribution companies and the second six telcos. However, the CRTC had increased the business risk of the telcos by opening their long distance markets to competition and there was no doubt that their business risk was higher than that of the energy distribution companies. Normally this would have caused comparability problems. However, the CRTC also allowed their common equity ratios to increase to 55% to compensate for the increased business risk. Consequently at that time we judged the overall risk of the six telco sample to be useful in comparisons with energy distribution companies. Explicitly it was our judgment that no leverage adjustments were needed going from a telco sample with 55% common equity, that is, 45% debt to an energy distribution sample with much greater financial leverage.

By and large this continues to be my judgment: that the actions of regulators, like this Board, to equalise risk obviates the need for leverage adjustments. In fact, in the recent Alberta generic hearing the EUB specifically followed the lead of this Board and set common equity ratios for a large sample of ROE regulated companies such that they could *all* earn the same formula allowed ROE.

Q. WHAT IF THERE *ARE* SIGNIFICANT LEVERAGE DIFFERENCES?

A. The first question the Board has to ask is: are these leverage differences real, that is, were they set to equalize overall risk or not? The second question the Board has to ask is: are the leverage differences based on market or regulated book weights? If the answer to the first question is that the leverage differences just offset business risk differences, then no action is needed. If the answer to the second is the differences are only due to "temporary" market value differences then they should also be ignored.

To continue with the previous example where the equity cost dropped from 15% to 11% and as a result the equity market value increased and the equity ratio at market values increased to 57.7% from the regulated 50%. Suppose this were the sample average from say twenty companies and the results had to be applied to a non-traded regulated firm with 50% common equity and the same business risk as the sample. Dr. Kolbe would seem to argue that the sample average has less financial risk and that to apply the estimated equity cost, assuming it is accurate, to the regulated firm in question underestimates its fair ROE, since it has a 50% debt not 42.3%. As a result, he would increase the recommended ROE from the 11% estimated from the sample or conversely recommend a higher common equity ratio. I will show later that their leverage adjustment gives the highest plausible leverage adjustment. However, the approach itself is wrong for two reasons.

First, if the regulated firm is earning approximately the same allowed ROE and has the same capital structure, there is no reason to believe that its implicit market valued equity ratio is any

TAB 2

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NATIONAL ENERGY BOARD

OFFICE NATIONAL DE L'ÉNERGIE

Order No. RH-2-94

Ordonnance N° RH-2-94

Group One Pipelines

Multi-Pipeline Cost of Capital Hearing for the Group One Pipelines Under the National Energy Board Jurisdiction

Hearing held at
Audience tenue à

Calgary, Alberta

7 December 1994
7 décembre 1994

Volume 22

Canada

This publication is the recorded verbatim transcript and, as such, is taped and transcribed in either of the official languages, depending on the languages spoken by the participant at the public hearing.

Cette publication est un compte rendu textuel des délibérations et, en tant que tel, est enregistrée et transcrite dans l'une ou l'autre des deux langues officielles, compte tenu de la langue utilitisée par le participant à l'audience publique.

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ORDER NO. RH-2-94
ORDONNANCE No RH-2-94

IN THE MATTER OF the National Energy Board Act and the Regulations made thereunder; and
IN THE MATTER OF Directions on Procedure Respecting a Public Hearing Concerning the Cost of Capital of: Alberta Natural Gas Company Ltd.; Foothills Pipe Lines Ltd.; Interprovincial Pipe Line Inc.; TransCanada PipeLines Limited; Trans Mountain Pipe Line Company Ltd.; Trans-Northern Pipelines Inc.; Trans Qubec & Maritimes Pipeline Inc.; and Westcoast Energy Inc.
RELATIVE A la Loi sur l'Office national de l'energie et a ses reglements d'application; et
RELATIVE A une audience publique concernant le cot du capital de l'Alberta Natural Gas Company Ltd.; Foothills Pipe Lines Ltd.; Interprovincial Pipe Line Inc.; TransCanada PipeLines Limited; Trans Mountain Pipe Line Company Ltd.; Trans-Northern Pipelines Inc.; Trans Quebec & Maritimes Pipeline Inc.; et Westcoast Energy Inc.

\- - -

Hearing held at Calgary, Alberta on Wednesday, 7 December, 1994
Confrence tenue a Calgary, Alberta, le mercredi, 7 decembre 1994

\- - -

R. Priddle	Chairman/President
A. Cote-Verhaaf	Member/Membre
C. Belanger	Member/Membre

K.W. Vollman	Member/Membre
R.L. Andrew	Member/Membre

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III

EXHIBITS/PIECES JUSTIFICATIVES

DR. BOOTH: Approximately, yes.

Q. You gave evidence in the Generic Hearings in British Columbia respecting the fair rate of return and capital structure for, amongst others, BC Gas?

DR. BOOTH: That is true.

Q. So you are somewhat familiar with

the affairs of BC Gas, are you?

DR. BOOTH: Yes.

Q. This shortfall that you have indicated, of approximately 9 1/2 percent, why did that occur in 1992?

DR. BOOTH: I seem to remember that it was weather related. I cannot remember the exact specifics. That prompted the BCUC to look at the weather stabilization account because of its impact on BC Gas.

Q. Do you know, Dr. Booth or Dr. Berkowitz, if that 2.7 percent actual value is a value for BC Gas, the utility, or a value for BC Gas on a Consolidated basis?

DR. BOOTH: In 1992 the Consolidated BC Gas rate of return was 3.9 percent, as reported by Financial Post.

Q. So I take it that you think that the 2.7 is a regulated only number?

DR. BOOTH: As I say, I called up Bob Follis of CBRS and asked exactly what these actuals versus allowed were. He said that they were the regulated, and he told me specifically that the data from the pipelines came from the surveillance reports.

Q. Okay.

DR. BOOTH: Because that was the primary focus.

Q. Will you agree me that the appropriate value for comparison would be the regulated only value?

DR. BOOTH: That is correct.

Q. I am going to show you a document entitled "Witness Aid Showing the Computation of BC Gas' 1992 Actual Rate of Return on Common Equity".
--- (Document handed to witnesses/Document remis aux temoins)
MR. JOHNSON:
Q. And that has attached to it pages from the BC Gas 1993 Annual Report to shareholders.

We can quickly run through this, if you will bear with me, gentlemen. From page 46 of the Annual Report of BC Gas, you will see the year-end Consolidated common equity numbers that appear on the front page of this document I have handed you. They are for 1991 and 1992.

You will see them on page 46, under the columns 1991 and 1992, about halfway down the page.

DR. BOOTH: Yes.

Q. And then Less: Cost of Shares held by Trans Mountain. That appears in the same columns, just two below, the 41 million?

DR. BOOTH: Yes.

Q. Do you understand what those are? They are the shares of BC Gas held by, at that time, its partially owned subsidiary, Trans Mountain?

DR. BOOTH: Yes.

Q. And that gives a year-end net Consolidated common equity of the figures that I have on the first page of this document. Do you understand how those are arrived at? It is just a subtraction of one number.

DR. BOOTH: They are just netting it out because otherwise you double count.

Q. Then you have an average 1992 Consolidated common equity, which is just the average of the 1991 and 1992 figures, coming up with $452,912,500?

DR. BOOTH: Yes.

Q. Then if you look at page 25 of the BC Gas Annual Report, in the 1992 column, four sets of figures from the bottom, earnings applicable to

common shares, of $11,992,000?

DR. BOOTH: Yes.

Q. And that works then out to an actual 1992 rate of return on common equity for BC Gas Inc. of 2.65 percent?

DR. BOOTH: Yes.

Q. Looking at the Annual Report material that is there, if you look at the third page in, which is page 1 of the Annual Report, you will see that BC Gas Inc. is the parent company, and there are a number of operations below it?

DR. BOOTH: Yes.

Q. You are aware of that.

BC Gas is over on the left-hand side of that organization chart.

Just going back to page 25 of the Annual Report for a moment, I pointed out the $11,992,000 figure. Four sets of numbers above that it says: "Write-off of discontinued project, net of deferred income taxes and minority interest".

DR. BOOTH: Yes.

Q. Do you know what that is?

DR. BOOTH: Not without looking at Note 13.

Q. Okay.

DR. BOOTH: That is the Low Point operation.

Q. Low Point operation. And you are aware of that, are you?

DR. BOOTH: I had been aware of it

at one point in time. BC Gas spent a lot of money developing it, and never went through with it.

Q. And you say "BC Gas". Was it BC Gas that spent the money?

DR. BOOTH: BC Gas, the holding company.

Q. Will you accept, having looked at this material from the Annual Report, that the 2.7 percent that you have used in your Schedule 20 is a return for the Consolidated enterprise BC Gas Inc., and not for the regulated-only operations?

DR. BOOTH: It certainly appears that way. It would seem highly coincidental that the BC Gas regulated operations would earn the same rate of return as the parent corporation. The bulk of the reduction in earnings clearly is the earnings before minority interest and discontinued project, where they are about half what they were in 1992 to what they were in 1993. But clearly the

write-off would have depressed the rate of return even further.

Q. Right. Now from your involvement in that generic hearing in British Columbia which discussed BC Gas, can you tell us whether the achieved rate of return on the common equity for BC Gas, the utility, in 1992, was really 9 1/2 percent less than the awarded rate of return?

DR. BOOTH: It was certainly less. I would have to go back and check how much less it was. But it certainly was significant because BC Gas came back and requested weather stabilization accounts because the result had been so significant.

I think to be fair here, Mr. Johnson, you are absolutely correct that it appears that the results for BC Gas are for the holding company. So I should go back to CBRS and talk to Bob Follis again.

Also, when we look at this for BC Gas, there are two just two years of data, for the reasons that we talked about before. And even though 1993 and 1992 are reversed, BC Gas, because there are only two years of data in the CBRS data, is not a significant part of the data on which we base our recommendation.

Q. Well, I am having a little problem here, Dr. Booth. You have given evidence that you appeared in the B.C. Generic Hearing. You gave evidence relating to the capital structure of BC Gas.

In this Hearing, on your Schedule 20, you discuss the variation in returns of gas distributors, LDCs. But isn't that something that you looked at in the BC Gas Hearing? Did you not look and see what sort of variations BC Gas had?

DR. BOOTH: If you remember, Mr. Johnson, we accepted the recommendation that BC Gas had on its capital structure, and we did not do an in-depth analysis of BC Gas' capital structure.

What we have here is a set of data produced by CBRS that I checked out with CBRS to make sure it indicated what I thought it indicated, and I have reproduced the data here, except for mislabelling of one of the years.

Q. You have reproduced it and you have relied on it?

DR. BOOTH: Well, I reproduced it, and it certainly affected my judgment. But it was not totally taken without qualification. We can

look at the pipeline data that CBRS provided in Schedule 19. We looked at that data as well as the surveillance data, and there is some inconsistency in that data.

So there are some numbers on Schedule 19 that CBRS provided that I happen to disagree with.

Q. Well, we will try to get over this quickly. I do have one other document for you, and I will ask you to take something subject to check.

Just to identify it, this is a fax from Sandra Jones of BC Gas Utility to Ms. Moreland of Interprovincial Pipe Line, which has attached to it material from the revenue requirement application that BC Gas filed in front of the British Columbia Utilities Commission, and the information attached from the BC Gas filing shows the utility returns.

If you will look under Common Equity,

down at line 18, rate of return on common equity ---

Do you see that?

DR. BOOTH: Yes.

Q. -- you will see that the rate of return actual on common equity was 9.06?

DR. BOOTH: Yes.

Q. Will you accept, subject to check, that the 9.06 percent is the actual rate of return on common equity for BC Gas, the Utility, for the year 1992, as filed with the British Columbia Utilities Commission?

DR. BOOTH: Yes.

Q. And the difference between the 9.06 percent and the 12.25 percent allowed is a lot smaller than the negative 9 1/2 percent that you show on your Schedule 20, isn't it?

DR. BOOTH: That is correct.

Q. And now if you look still at line 18, and over in the column entitled "Normal", you see a value of 12.39 percent.

DR. BOOTH: Yes.

Q. Will you accept, subject to check, that the 12.39 percent is the rate of return on common equity for BC Gas, the Utility, as normalized for weather variations?

DR. BOOTH: That is correct.

Q. And if the 12.39 percent were substituted for the 2.7 percent in your Schedule 20, the difference between 1992 BC Gas allowed and the actual rate of return for the utility operations would be plus 14 basis points instead of

a negative 955 basis points?

DR. BOOTH: That is correct. That indicates what I have said, that the major factor in 1992 for BC Gas Utility was the weather deviations, which is why BC Gas was prompted to bring forward to the BCUC a weather stabilization account. On a normalized basis, as you just indicated, they marginally over-earned.

I should point out that when we are looking at capital structures, the effect of weather is one of the most significant factors for gas LDCs, primarily because when you look at the Consolidated statements, and the firms have a significant deviation in their actual rate of return because of a warm winter, they earn a low rate of return. And as a result, the interest coverage restrictions in their bonds kicks in.

I know, for example, that Consumers' Gas had significant problems in financing, partly because weather effects lowered the rate of return they earned, and as a result, the interest coverage ratio made it very difficult for them to access capital.

So when we look at capital structures, normalization does not do the company any good,

because the effect of weather may still impact their ability to access capital markets.

MR. JOHNSON: I do not believe that we marked the last two documents I provided to you.

The first one is the Witness Aid showing computation and the BC Gas.

THE CLERK: That will be Exhibit No. B-1-50.

--- EXHIBIT NO. B-1-50:

Document entitled "Witness Aid Showing the Computation of BC Gas' 1992 Actual Rate of Return on Common Equity.

MR. JOHNSON: And the fax cover sheet with the attachment will be the next exhibit.

THE CLERK: That will be Exhibit No. B-1-51.

--- EXHIBIT NO. B-1-51:

Fax cover sheet from S. Jones, BC Gas Utility to W. Moreland, IPL, with attached revenue requirement material filed before BCUC.

MR. SCHULTZ: Mr. Chairman, I am somewhat perplexed in the sense that it is customary in these proceedings, in matters that involve computations, technical matters,

reconciliation of numbers that people may or may not understand, to facilitate that by providing material in advance.

We have now had a series of this kind of questioning, and I am just wondering if there is some reason that this and what may be coming has not been provided in an effort to make better use of the time than perhaps may have been made the last hour or so.

MR. JOHNSON: I do not think we have any more calculations, if that will assist.

THE CHAIRMAN: Mr. Johnson, I was thinking of taking the break at this point.

MR. JOHNSON: That is convenient.

THE CHAIRMAN: We will take a 15-minute break.

DR. BOOTH: Can I comment, Mr. Chairman, that this information comes from the BC Gas Application that was withdrawn. And we never had this data.

DR. BERKOWITZ: We did not participate in that hearing. It was withdrawn. We participated in the one the year after, the generic one. But we did not participate in this and we did not have this information that you are referring to

here.

THE CHAIRMAN: Thank you.

--- Short Recess/Pause

--- Upon resuming/A la reprise de l'audience

THE CHAIRMAN: Mr. Johnson...?

CROSS-EXAMINATION BY MR. JOHNSON, on behalf of TCPL/TMPL (Continued):

MR. JOHNSON:

Q. I have some more paper for you, gentlemen, but not a calculation.

--- (Document handed to witnesses/Document remis aux temoins)

MR. JOHNSON:

Q. What I have just handed you is an extract from your BC Gas Evidence earlier this year. The cover page is from Part B of your Evidence. That dealt with capital structure, as I understand it.

Correct?

DR. BOOTH: Yes.

Q. Could you turn to page 4, line 26, the final paragraph on that page.

DR. BOOTH: Yes.

Q. There you say:

"The impact of weather on the demand

for gas is immediate and obvious, since a large amount of the demand for gas is derived from the demand for space heating. Investors are well aware that weather causes predictable fluctuations in the profitability of gas distributors. They are also aware that this component of the uncertainty in earned returns is random and can be diversified away by investors by including the stock in a portfolio of shares. For example, whether or not the winter is exceptionally cold or mild has no impact on the behaviour on the TSE 300 index, whereas it may have significant impact on a gas distributor. From the investor's point of view, the random fluctuations in the price of a gas company's shares caused by warmer than usual weather in one part of the country is completely diversifiable. As a result, it should have no impact on the investors risk assessment of the firm or the investor's required return."

And the word "no" in that last sentence was bolded in your Evidence?

DR. BOOTH: Yes.

Q. And that was your Evidence before the British Columbia Utilities Commission.

DR. BOOTH: And still would be our

Evidence.

MR. JOHNSON: Thank you.

If that could be marked as an exhibit.

THE CLERK: That will be Exhibit No. B-1-52.

--- EXHIBIT NO. B-1-52:
Evidence of Drs. Booth and Berkowitz re
Fair Rate of Return on Common Equity
for a "Generic" Regulated Utility
(Part B) dated March 1994.

DR. BOOTH: This risk assessment is looking at the business risk of the company. We do not believe that the variability of weather affecting rates of return is a factor that investors place much value on in terms of the fair rate of return, because it is not a function of the long-run expected cashflows they expect from the company.

As I indicated earlier, it does affect

the financing of the company. I seem to remember there was cross-examination at the BCUC where we agreed, as we have always agreed, that weather, by affecting the rate of return, affects the interest coverage ratio that the gas distributors are constrained by and, as a result, affects their financial flexibility.

Q. Your Evidence, as I have just quoted, says as the last sentence, and it is there talking about variations in earnings caused by weather:

"As a result, it should have no ---"

And the "no" is bolded.

"-- no impact on the investors risk
assessment of the firm or the
investor's required return."

DR. BOOTH: That is correct.

MR. SHULTZ: To be accurate, it is the extract that says that. It is not the entire evidence.

MR. JOHNSON: The extract says that.

Q. And "investor's required return" relates to the return on equity, does it?

DR. BOOTH: That is correct. If you

are looking at an investor that is investing

through Union or Interprovincial, or any other company with diversified operations, and in fact holds a portfolio of shares, the impact of the weather in British Columbia is uncorrelated with the weather in Ontario, is uncorrelated with the weather in London. As a result, the weather variations tend to even out and have no impact on the riskiness of a portfolio and, as a result, do not affect the investor's risk assessment of the firm or the investor's required return.

DR. BERKOWITZ: I think one of us suggested back then at the BCUC hearings that weather was indeed a classic example that you give in class as a diversifiable risk when you are talking about diversifiable versus non-diversifiable risk in the Capital Asset Pricing Model.

Q. And this extract of the Evidence -- to use Mr. Schultz's word -- was found in ---
MR. SCHULTZ: Well, it is accurate. Period.

MR. JOHNSON:
Q. -- was found in Part B of your Evidence, and that was the capital structure portion?

DR. BOOTH: That is correct. It was not directly the rate of return portion.

Q. And the ---
DR. BOOTH: But if I remember rightly, it was also the financing portion as well. I think in Part B before the BCUC we included a lot of discussion on financial flexibility.

Q. I think we have already discussed -- and you have agreed -- that if you took the weather fluctuations out for BC Gas, it would result in much less variability in the return.

DR. BOOTH: That is correct.

To reiterate, that will have very little impact, if any impact, on the investor in terms of the return requirements, but will have an impact on the firm in terms of its financing simply because it is subject to certain balance sheet ratio constraints.

DR. BERKOWITZ: We cannot get confused in looking at market required returns and opportunity cost, and allowed book returns and regulated returns.

DR. BOOTH: If I remember rightly, the BCUC agreed with the position that we put

forward and the position that Dr. Waters put forward: that a number of bad years, like two, three, four years of very bad weather -- i.e., very warm weather -- would mean that BC Gas' rate of return would go down and, as a result, it would have difficulty accessing the funded debt market which required a two times interest coverage restriction.

So that might impose financing problems for BC Gas and affect its financing.

Q. When you put the data on your Schedule 20 for the companies other than BC Gas, do you know whether or not the values for the companies other than BC Gas reflect weather normalization?

DR. BOOTH: I would be surprised if they do. Usually that information is only in the regulatory hearings. Weather normalized is basically a regulator's calculation. It is an attempt to sort of look at the results and work out how much was due to random occurrence that the company cannot control, i.e., the weather, and how much really reflects under or over-earning based upon the financial projections that went into the forward test year calculations.

So I think that is primarily a calculation that the regulator is interested in. The financial markets are interested in what was the rate of return.

Q. And the final document that I have in this area, gentlemen, is another extract from your Evidence before the British Columbia Utilities Commission. This was from your Part A Evidence in that proceeding. And this is from page 18. I am referring you to the paragraph that starts at line 15, where you talk about a graph of the utility subindex and betas. And you say at line 18:

"The pipeline betas are for comparison

TAB 3

Application No. 1271597

Board File No. 5681-1

ALBERTA ENERGY AND UTILITIES BOARD

IN THE MATTER OF

GENERIC COST OF CAPITAL PROCEEDING

FAIR RETURN FOR AN ALBERTA UTILITY

WRITTEN EVIDENCE OF

DR. LAURENCE D. BOOTH

on behalf of

THE CITY OF CALGARY

and

CANADIAN ASSOCIATION OF PETROLEUM PRODUCERS (CAPP)

September, 2003

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EXECUTIVE SUMMARY

The City of Calgary (Calgary) and the Canadian Association of Petroleum Producers (CAPP) have asked me to provide an independent assessment of the fair rate of return on common equity for an Alberta utility, to discuss the appropriateness of an automatic adjustment mechanism and to critique the rate of return evidence filed on behalf of the companies involved in this proceeding (Appendix B).

The overall assessment is as follows:

- Canada is recovering from a mild slowdown which has slowed the increase in interest rates that Professor Berkowitz and I anticipated in the first half of the year. Long Canada rates are now expected to average 5.50% for 2004, while the Consensus forecast is that rates will stay around this level over the next year. Inflation is also expected to slow marginally to settle at the mid point of the Governor of the Bank of Canada's range of 1.0-3.0%.

- Using the traditional risk premium test, utilities are assessed as having relative risk of 45-55% of the market as a whole and the current market risk premium is 4.5%. Recent market risk premium studies support this 4.5% estimate, rather than the 4.5-6.0% range used by the Board in its AltaLink decision (U2003-61). Including estimates from a multi-factor risk premium model gives an average ROE of approximately 7.6%. Adding the Board's customary 50 basis point "cushion" gives a fair ROE of 8.12%. However, the Board may want to revisit this "cushion" since some of the utilities have not asked for a flotation allowance and others may be in a period of a declining rate base and have no need for one. Further a straight flotation allowance indicates an additional 15 basis points, rather than the Board's customary 50 basis points.

- Business risk and capital structure adjustments are assessed separately in Appendix A. However, I recommend that the Board adjust for underlying business risk differences through the use of deferral accounts, as far as is practicable, and then changes in the common equity ratio. The Board can then apply the same ROE to all the utilities in its jurisdiction. Hence, I recommend that NGTL should be allowed 33% common equity and Altalink 30%, but they should both have the same allowed 8.12% ROE. As a reference point Terasen (BC) Gas is allowed a 33% common equity ratio by the BCUC and Pacific

Northern Gas (PNG) 36%. Moreover, faced with increased risk attached to PNG the BCUC set up a special large industrials deferral account rather than adjusting the ROE or equity ratio.

- Formula adjustment mechanisms are now in use in the major jurisdictions in Canada, and have been reviewed and continued by the BCUC, the Manitoba PUB and the NEB. The OEB is also currently reviewing its formula. In my judgement the use of an adjustment mechanism with currently allowed parameters overstates the fair ROE, particularly after it is recognized that the use of an adjustment mechanism lowers the risk to a utility investor. This is because it converts the equity investment in a utility into a form of floating rate preferred share, where observed yields are significantly lower than current allowed ROEs.

- I would recommend that the Board adopt the NEB adjustment mechanism with a 0.75 adjustment of the ROE to changes in the long Canada bond yield based, as in the NEB formula, on the Consensus forecast of over ten year Canada yields plus a yield spread adjustment. However, I recommend setting the "going in" risk premium at 262 basis points, rather than the 240 basis points of the recent Altalink decision. There is no evidence that the use of an adjustment mechanism has harmed shareholders or caused a loss in financial flexibility.

- A utility can ask for its allowed ROE to be reviewed any time that it judges it to be unfair. This practise would continue with an adjustment mechanism and in my judgement puts the utility in a more favourable position than interveners. The reason for this is that interveners generally react to the evidence put forward by the company and are unlikely to be in a position to constantly review the implications of a formula. For this reason a 3.0% band around the 5.5% forecast long Canada bond yield should be set that automatically triggers a review of the adjustment mechanism and a full ROE hearing for the following year. Typical "sunset" clauses have been three years, but given the success of the formula adjustment mechanisms in other jurisdictions I feel confident that the Board will not have to review its formula as long as long Canada yields stay within this band over the next five years.

- My recommendations preserve the utilities' financial flexibility with traditional financial parameters. However, given the concern expressed by US rating agencies, resulting from their US experience, the Board may have to institute formal “ring fencing” policies to ensure that the utilities are not harmed by the possibilities of control changes or other actions undertaken by their corporate parents. The actions of AltaLink in ring fencing the utility and achieving an A- credit rating for the utility operations, while the corporate credit rating is BBB might be a blueprint for others to follow.

These companies are predominantly pure utilities with Foothills and TQM primarily reflecting the impact of the NEB formula approach, NGTL the impact of negotiated settlements that have allowed it to earn more than the NEB regulated pipelines and Westcoast's more diversified operations.

Q.30 *Why have you used 35% common equity a current debt cost and a 40% tax rate?*

A. These are reference numbers. If the allowed common equity ratio drops to 30% then the coverage ratio drops to 1.92X, since the overall EBIT drops while there is more interest. If the tax rate also drops to zero, the coverage ratio drops to 1.55X and is equivalent to that of Crown corporations that do not pay income taxes. For references purposes the interest coverage ratios for BC Hydro and Hydro-Quebec have been as follows:

Table 11

Public Sector Coverages

	2001	2000	1999	1998	1997	1996
BC Hydro	1.54	2.40	1.91	1.64	1.65	1.47
Hydro Quebec	1.36	1.34	1.29	1.22	1.26	1.16

Finally, I have used a current cost of debt since that is an approximate interest coverage ratio consistent with the recommended ROE.

It makes no sense to target a particular interest coverage ratio and allow a higher ROE simply because a utility has a high embedded cost of debt. For example, suppose a utility has a current embedded cost of debt of 10.0%. In this case with my recommended ROE its cost of capital would be calculated as follows:

Table 12

WACC with High Embedded debt Cost

	Pre-Tax	After-Tax	Weighting
Senior debt	10.0%	6.00%	65%

Common equity	13.5%	8.12%	35%

for a pre tax cost of capital of 11.24% and an interest coverage of 1.73X, down from the 2.15X with the current cost of debt. Clearly, with the ROE set on the basis of lower interest rates, firms with higher embedded debt costs will see their coverage ratios squeezed.

With a lower interest coverage ratio it is possible that a utility could be downgraded, particularly by a rating agency that simply "runs the numbers." In this case, it is possible that the utility would ask for a higher ROE to target say the 2.15X coverage that it would have with a current cost of debt. This would mean an ROE of almost 13%. However, awarding an ROE of 13% makes no sense since the pre tax cost of capital increases to 14.08% compared to the current cost estimate of 8.83%. In effect, the rate payer is paying twice for the higher embedded cost of debt: once and directly through the higher embedded interest cost and again, indirectly, through the higher ROE required to maintain the interest coverage ratio. Obviously, it is in the interests of the company to ask for a higher ROE to compensate for the higher embedded cost of debt, but this is rewarding the equity holder with a higher ROE simply because interest rates have dropped.

The correct answer to these types of market access problems is the use of preferred shares. I showed earlier that according to Nesbitt Burns, retractable preferred shares are currently yielding 3.72%. If a regulated utility has a high embedded cost of debt then it can target the use of retractible preferreds to boost its interest coverage ratio until the high embedded cost debt can be refinanced. For example, using the same numbers as before, the 2.15X interest coverage can be obtained in the following way:

Table 13

WACC with Preferred Shares

	Pre-Tax	After-Tax	Weighting
Senior debt	10.0%	6.00%	50%
Preferred shares	6.02%	3.72%	15%
Common equity	13.5%	8.12%	35%

The overall before tax cost of capital is 10.67% and the interest coverage 2.13X. The rate payer is still paying the high embedded cost of debt, but is no longer also paying for an inflated ROE. This example is exaggerated for effect, but the point is that an allowed ROE of 8.12% is consistent with long Canada bond yields of 5.5% and the preservation of interest coverage ratios and financial flexibility. Any problems unique to individual firms can be solved by the use of preferred shares, instead of debt, in any incremental financing, rather than a costly increase in either the ROE or the common equity ratio.

Q.31 *DOES THIS CONCLUDE YOUR TESTIMONY?*

A. Yes.

APPENDIX A

CAPITAL STRUCTURE AND ADJUSTMENT FOR BUSINESS RISK

To set fair and reasonable rates the Board needs to set both a fair ROE and a fair capital structure for the regulated firm (equity ratio). In this appendix I discuss how the Board can determine the capital structure and other financial policies for the firms under its jurisdiction such that they can then all receive the same allowed ROE via an appropriate adjustment mechanism. It is important in this respect that the board recognise any perceived risk differences and adjust for them in a consistent manner, rather than repeatedly adjusting for the same risk differences in multiple areas.

I: Regulatory Tools for Managing Risk

Investors are interested in the rate of return on the market value of their investment. This investment can be represented by the standard discounted cash flow model:

$$P_0 = \frac{ROE * BVPS * (1-b)}{(K-g)} \qquad (1)$$

where P_0 is the stock price, *ROE* the return on equity, *BVPS* the book value per share, b the retention rate (how much of the firm's earnings are ploughed back in investment) and K and g are the investor's required rate of return and growth expectation respectively.

The discounted cash flow (DCF) model[1] is useful for thinking of the sources of risk to the investor. Some of these risks stem from the firm's operations and financing and others come from the capital market's perception of the firm and general capital market conditions. For regulated utilities we also add another dimension, which is the impact of *regulatory* risk. In terms of the DCF equation the actual earned return on equity **(ROE)** captures the business, financial and regulatory risk, which together I term ***income*** risk, whereas all the other factors are reflected in ***investment*** risk, which is the way in which

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[1] See Appendix G for a discussion of the basic DCF model.

investors react to the income risk and other variables such as the firm's growth prospects and exposure to interest rates.

Business risk is the risk that originates from the firm's underlying "real" operations. These risks are the typical risks stemming from uncertainty in the demand for the firm's product resulting, for example, from changes in the economy, the actions of competitors, and the possibility of product obsolescence. This demand uncertainty is compounded by the method of production used by the firm and the uncertainty in the firm's cost structure, caused, for example, by uncertain input costs, like those for labour or critical raw or semi-manufactured materials. Business risk, to a greater or lesser degree, is borne by **all** the investors in the firm. In terms of the firm's income statement, business risk is the risk involved in the firm's earnings before interest and taxes (EBIT). It is the EBIT, which is available to pay the claims that arise from all the invested capital of the firm, that is, the preferred and common equity, the long term debt, and any short term debt such as debt currently due, bank debt and commercial paper.

If the firm has no debt or preferred shares, the common stock holders "own" the EBIT, after payment of corporate taxes, which is the firm's net income. This amount divided by the funds committed by the equity holders (shareholder's equity) is defined to be the firm's return on invested capital or ROI, and reflects the firm's operating performance, independent of financing effects. For 100% equity financed firms, this ROI is also their return on equity (ROE), since by definition the entire capital investment has been provided by the equity holders. The uncertainty attached to the ROI therefore reflects all the risks prior to the effects of the firm's financing and is commonly used to measure the business risk of the firm.

As the firm reduces the amount of equity financing and replaces it with debt or preferred shares, two effects are at work: first the earnings to the common stock holder are reduced as interest and preferred dividends are deducted from EBIT and, second the reduced earnings are spread over a smaller investment. The result of these two effects is called financial leverage. The basic equation[2] is as follows:

$$ROE = ROI + [ROI - R_d(1-T)]\frac{D}{S}$$

where D, and S are the amounts of debt, and equity respectively, T is the corporate tax rate and R_d is the embedded debt cost. If the firm has no debt financing (D/S =0), the return to the common stockholders (ROE) is the same as the return on investment (ROI). In this case, the equity holders are only exposed to business risk. As the debt equity ratio increases, the spread between what the firm earns and its borrowing costs is magnified. This magnification is called financial leverage and measures the ***financial risk*** of the firm.

The common stockholders in valuing the firm are concerned about the total "income" risk they have to bear, which is the variability in the ROE. This reflects both the underlying business risk as well as the added financial risk. If the firm operates in a highly risky business, the normal advice is to primarily finance with equity, otherwise the resulting increase in financial risk might force the firm into serious financial problems. Conversely, if there is very little business risk, as is the case with most regulated utilities, the firm can afford to carry large amounts of debt financing, since there is very little risk to magnify in the first place.

This means that a regulatory board has a variety of tools to manage the regulated firm's risk. The **first** tool is that it can set up deferral accounts to capture different components of business risk. The essence of deferral accounts is simply to capture forecasting errors. For example, if the operating and maintenance expense is 2% higher than forecast, rather than have the utility's stockholders "eat" the extra costs in terms of a lower earned rate of return, the board can simply have the extra costs captured in a deferral account and then,

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[2] Note this equation captures how the actual ROE varies with operating profits. It does not show how the investors required rate of return varies with financial leverage. This requires a valuation model to understand how debt tax shields for example affect value.

subject to a standard prudency review, charged to the following years' ratepayers. In this way "ratepayers" always pay the full cost of service and stockholder risk is lowered.

Different boards have a different attitude towards deferral accounts, which reflects one of two factors: 1) the stability of the ratepayer group; and 2) the desire to hold management accountable for the utility's costs. If the ratepayer group changes dramatically over time, deferral accounts can end up having a future group pay the cost over-runs that are not part of their "fair and reasonable" costs. However, deferral accounts are very useful when management cannot control or accurately forecast costs and the ratepayer group is fairly stable.

A **second** tool is for the regulator to alter the amount of debt financing. If the regulator feels that the firm's business risk has increased (decreased) it can reduce (increase) the amount of debt financing so that the total risk to the common stockholder is the same. Both of Canada's national regulators, the National Energy Board and the CRTC, have recognized this. When the CRTC opened up Canada's telecommunications market to long distance competition it specifically increased the allowed common equity component of the Telcos to 55% to offset the increased business risk. Similarly, when the NEB decided to go to a formula based approach for the return on equity it reviewed all the capital structure ratios for the major oil and gas pipelines and set different equity ratios for the firms that it believed faced different business risks. TransCanada, for example, was allowed 30% common equity[3], since it predominantly had mainline transmission operations, while Westcoast with its greater proportion of gathering and processing lines was allowed 35%. Once the financial risk had offset the different business risks, the NEB was able to award them all the same return on equity.

The **third** tool available for the regulator is to directly alter the allowed rate of return, so that the stockholder only earns a rate of return commensurate with the risks undertaken. The CRTC, for example, has historically allowed Northwestel 0.75% more than the other

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[3] In RH-4-2001 (June 2002), the NEB increased the TCPL Mainline's common equity ratio to 33%, Westcoast is allowed 30% equity on its mainline transmission assets.

maximises the use of the tax advantages from debt financing, while maintaining the utility's financial integrity and ability to raise capital to provide service.[8] This amount of debt will vary across the different utilities depending on their net business risk after taking into account regulatory protection.

3: Business Risk Rankings

The risks faced by the stockholder in the DCF equation (1) can be divided into short and long term risks. The short term risks are essentially the ability of the regulated firm to earn its allowed ROE, which is what I previously termed income risk, while long term risks refer to the growth in these future cash flows and the risk of not being able to recover the capital invested.

The major short term risks stem from both cost and revenue uncertainty.

- On the cost side since regulated utilities are capital intensive most of their costs are fixed. The major risks are in *operations and maintenance* expenditures. However, over runs are usually under the control of the regulated firm and can be time shifted between different test years.
- On the revenue side the risks largely stem from rate design, critical features are:
    - Who is the customer and what *credit risk* is involved. For example, electricity transmission operators who recover their revenue requirement in fixed monthly payments from the provincially appointed TA, who is responsible for system integrity, have less exposure than the local gas and electricity distributors who recover their revenue requirement from a more varied customer mix involving industrial, commercial and retail customers.
    - Is there a *commodity charge* involved? The basic distribution function is very similar to transmission, except when the distributor buys the gas or electricity wholesale and then also retails the commodity. The distributor is then exposed to weather and price fluctuations depending on rate design.
    - Even if there is no commodity charge, how much of the revenue is recovered in a *fixed versus a variable usage* charge? Utilities that recover their revenue in a fixed demand charge face less risk than those where the revenues have a variable component based on usage.

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[8] Generally in Canada this means at least a BBB bond rating or better for a reasonable sized utility. According to S&P in the US 43% of utility holding company debt is now BBB and a further 18% is non-investment grade.

The above risks are all moderated by whether or not the Board allows deferral accounts.

The medium and long term risks are mainly as follows:

- *Bypass risk.* The economics of regulated industries are as natural monopolists involved in "transportation" of one kind or another. However, one utility may not own all the transportation system so that it may be economically feasible to bypass one part of the system. This happens for local gas distributors, when a customer can access the main gas transmission line directly, rather than through the LDC, or when a large customer may be able to bypass part of the transmission system. This is largely a rate design issue: a postage stamp toll clearly leads to uneconomic tolls and potential bypass problems, whereas distance or usage sensitive tolls will discourage it. Similarly, rolled in tolling will encourage predatory pricing by potential regulated competitors.

- *Capital recovery* risk. Since most utilities are transportation utilities, the critical question is the underlying supply and demand of the commodity. If supply or demand does not materialise then tolls may have to rise and the utility may not be able to recover the cost of its capital assets. Depreciation rates are set to mitigate this risk to ensure that the future revenues are matched with the future costs of the system.

A common thread running through the above brief discussion of utility risks is rate design and regulatory protection. There can be significant differences in underlying business risk that are moderated by the regulator in response to those differences. The lowest risk utility is then one with the strongest underlying fundamentals and the least need to resort to regulatory protection. In contrast, another utility may have similar short term income risk, but only because of its need to resort to more extensive regulatory protection, so that it faces more problematic longer term risks.

I have discussed the business risk of the Alberta utilities with both The City of Calgary and CAPP's support team and have been informed by their analyses. As a result of this interaction, my judgement is that the lowest risk regulated utilities in Canada are currently electricity transmission assets, since these have the following characteristics:

* Minimal forecasting risks attached to O&M

* Revenue recovery via the TA through fixed monthly charges

* Limited (non existent) by-pass problems

* Minimal capital recovery problems, since there are many suppliers of electricity as a basic commodity.

- Deferral account for capital expenditures

In the AltaLink and ATCO Electric hearings earlier this year Professor Berkowitz and I recommended 30% common equity ratios based in part on the National Energy Board's 30% allowed common equity ratio for mainline gas transmission assets. The Board allowed Altalink 32% based on its business risk and an additional 2% based on the tax status of 25% of its equity ownership. Nothing has changed since the AltaLink hearing and I would continue to recommend 30% common equity for the electricity transmission assets involved in this proceeding, but accept the Board's 32% equity ratio as reasonable.

I would place the gas transmission pipelines as the second lowest risk group. Here it is important to distinguish between the full cost of service pipelines like Foothills that have many of the same characteristics as the electricity transmission operations mentioned above. In fact I would classify Foothills and the TCPL BC System (formerly ANG) as of equivalent risk to AltaLink and ATCO Electric transmission. NGTL has marginally more risk than Foothills and the TCPL BC System, since it is exposed to bypass and recovers its revenues through a forward test year from a variety of shippers, rather than as a single monthly charge to the provincially appointed TA.

However, these risks are still minimal. NGTL sits at the heart of the Western Canadian Sedimentary Basis (*WCSB*) and although this basin is now maturing, it remains prolific, is not as mature as some of the other basins and is the natural intermediary for Northern as well as non-conventional gas such as coal bed methane. Further since the 1995 NGTL hearing, NGTL has become part of the TCPL system, has adopted distance sensitive tolls and has significantly increased its depreciation rate. The latter two are important changes.

Bypass risk depends on whether it is economic to build a new pipeline to compete with an existing one. If the existing pipeline (or gas LDC) is charging tolls that are not based on underlying economics but some other objective, such as developing gas reserves that are far from existing areas, then there is an implicit regulated subsidy that will encourage bypass. In this case, in order to avoid uneconomic duplication of facilities the regulator can either allow special bypass rates, or load retention service (LRS), to make sure that the load stays on system or change the rate structure to distance sensitive, economic based, tolls. In the case of NGTL this Board has allowed both.

Capital recovery depends on the continuing supply and demand for a firm's assets. When a depreciation rate is set the first step is to estimate the useful life of the asset, so that its cost can be correctly allocated over this useful life. This matching of revenues and costs is one of the basic principles of generally accepted accounting principles. As capital recovery risk increases then a shortening of an asset's useful life is accomplished through a higher depreciation rate. In RH-1-2002 the NEB increased the TCPL Mainline's depreciation rate from 2.89% to 3.42% to partially compensate for increased capital recovery risk. In contrast, it is my understanding that during the period when NGTL had negotiated rates, it negotiated an increase in its depreciation rate from the 2.96% rate at the time of its last GRA (1995) to the current level of 4.0%. Significantly in CAPP-NGTL-38c NGTL indicated that its plant would be substantially depreciated by 2021.

The combination of distance sensitive tolls, the ability to offer load retention service and a more rapid depreciation rate significantly reduce any increase in risk NGTL may have faced since 1995.[9] On its own I would judge that NGTL can maintain its financial flexibility on the same 30% common equity ratio the NEB allows Foothills and Westcoast's mainline gas transmission assets. This was what Professor Berkowitz and I recommended for the TCPL Mainline before the NEB in 2002. However, since NGTL is currently allowed 32%, based on the absence of a preferred share component, and is now almost indistinguishable from the TCPL Mainline, it makes sense to allow the same 33% common equity ratio the NEB now allows the Mainline.

The third group of utilities are the local distribution companies (LDCs), including both gas and electric. These companies are distinguished by their retail operations, which mean that their revenues are recovered from a large number of industrial, commercial and residential consumers. This exposes them to both the business cycle and weather

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[9] The change in policy towards laterals and the maintenance of rolled in tolls would also tend to lower NGTL's risk.

fluctuations. This revenue recovery is also a function of their rate design that may expose them to commodity charges and a fixed and variable recovery charge.

The conventional yardstick for LDCs is that Consumers (Enbridge Gas Distribution Inc or EGDI) and Union Gas are both allowed 35% common equity by the Ontario Energy Board. However, whereas the Ontario Energy Board allows a purchase gas variance account (PGVA) to ensure that the full costs of gas are recovered, they are still subject to volume related variances. In contrast, the BCUC allows BC Gas (Teresen Gas) a more comprehensive deferral account, but limits the allowed common equity ratio to 33%. With these yardsticks I recommend the same 35% common equity ratio that Professor Berkowitz and I recommended in the ATCO Gas GRA for all the Alberta LDCs.[10]

Finally, there is ATCO Pipelines (AP). In testimony filed in May 2003 Professor Berkowitz and I recommended a 42% common equity ratio as the "upper end of a reasonable range" for AP based on the increased competition from NGTL and regulatory uncertainty. As a small intra-Alberta pipeline AP is vulnerable to predatory pricing from NGTL and is reliant on regulatory protection from this Board. This will emerge in the joint hearing into rate design for AP and NGTL scheduled for March 2004. Absent this hearing I would continue to regard 42% as the upper end of a reasonable range, given that the BCUC allows PNG, a smaller and much riskier pipeline, 36% common equity. Should clear principles emerge on intra Alberta pipeline competition and rate design that lower AP's risk, then I would judge PNG's 36% allowed common equity ratio to be the upper end of a reasonable range.

Consequently, I recommend the following common equity ratios:

Lowest risk:	Electricity transmission assets, for example AltaLink, 30%
Very low risk:	Gas transmission assets, for example NGTL, 33%
Average risk:	Gas and Electric LDCs, for example, ATCO Gas 35%

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[10] Absent the merchant function the allowed common equity ratio can be reduced to at least the 33% of Terasen Gas. If the revenue requirement is recovered through a fixed delivery charge the allowed common equity ratio can be the same 30% I deem appropriate for the transmission wires and pipes.

Above average risk: ATCO Pipelines 36-42%, (depends on 2004 EUB decision)

In my judgement, none of the Alberta utilities are as risky as Pacific Northern Gas (PNG) or Gaz Metropolitain (GMI).

4: Utility Benchmarks

There are no publicly traded pure utilities left in Canada that also have a reasonable price history, except Pacific Northern Gas. This makes it difficult to estimate risk by looking at stock market data or by examining their financial statements. However, the National Energy Board in its Annual Report publishes abbreviated information on the regulated assets of the mainline gas pipelines under its jurisdiction. The most important information is a comparison of the actual to their allowed ROEs. For the Class 1 gas transmission pipelines, this information is in Schedule A1.[11] All of these pipelines are now part of TransCanada Pipelines,[12] but this has not always been the case and the NEB still maintains separate data for each pipeline.

Foothills and Alberta Natural Gas (ANG or now the TCPL BC system) are full cost of service pipelines and exactly earn their allowed ROE.[13] In contrast, the TCPL Mainline and TQM are forward test year plus deferral account companies, similar to the Alberta utilities in this hearing, in their case, they have consistently over earned their allowed ROE by 0.23-0.36%. It is difficult to see how this persistent over-earning can be classified as more "risk." Implicitly this was also the NEB's decision when it allowed all of these pipelines the same 30% common equity for their mainline gas transmission pipelines. However, *since Foothills exactly earns what the NEB allows, by definition,*

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[11] This data was confirmed in CAPP NGTL-17

[12] TQM is 50% owned by TCPL.

[13] In 2002 ANG failed to earn its ROE due to agreed sharing in the TCPL merger agreement.

TAB 4

Proceeding No. 1271597

ALBERTA ENERGY AND UTILITIES BOARD

GENERIC COST OF CAPITAL PROCEEDING
RULING ON PROCEDURAL AND TRANSITIONAL ISSUES

PROCEEDINGS

Volume 28

Calgary, Alberta

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Proceedings taken at Hearing, Alberta Energy and Utilities Board, Govier Hall, 640 - 5th Ave. S.W., Calgary, Alberta.

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January 7, 2004

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W. Taylor, Esq.	Board Staff
F. Tiberi, Esq.	Board Staff
R. Schroeder, Esq.	Board Staff
L. Smith, Esq.	For ATCO Utilities
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H. Williamson, Esq.	For AltaLink Management Ltd. (AltaLink)
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D. Wood, Esq.	
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B. Ho, Ms.	For Fortis Alberta Holdings Inc.
D. Crowther, Esq.	For EPCOR Utilities Inc.
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S. Young, Ms.	For Nexen Inc.
J. Bryan, QC	For Consumers Group - AUMA
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N. McKenzie, Ms.	For Public Institutional Consumers of Alberta (PICA)
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E. Kuemmel, CSR(A), RPR B. Mercer, Ms. CSR(A), RPR CRR	Official Court Reporters

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that to an economist they are all basically exactly the same, they are looking at the same number and the CAPM estimates that number.

Q. Capital attraction, sir, I believe yesterday there was a discussion, and it may have been with Mr. McCormick, but Dr. Booth, I'm really trying to keep this with yourself, that capital attraction is not the end of the story, that there is more to it than that, and that it did include financial integrity and fairness; is that fair?

A. DR. BOOTH: That's correct. I was going to interject yesterday, but the additional term, and I think -- I forget which of my colleagues said this, but you can attract capital at 4 percent or 80 percent, what was missing in their answers without criticizing them was the phrase "attract capital on reasonable terms." So I think if you go back to the case it's a question of what are reasonable terms.

So for example, in the 1960s and the 1970s when utilities were under a lot of pressure and their stock was selling below book value, they could certainly sell stock and raise capital but fundamentally that was not unreasonable terms, it represented dilution to the common stockholders.

Q. But they could raise capital?

A. DR. BOOTH: That's right, but the capital attraction test is that it raises capital on reasonable terms.

Q. Fair enough. But the fact is you can raise capital under, frankly, a very wide variety of economic circumstances that may or may not preserve the financial integrity of the company, and it may or may not be fair to existing shareholders; is that fair?

A. DR. BOOTH: Absolutely. You could push all of these companies in this hearing to 85 percent debt, downgrade their bonds to a double B or single B, they would still be able to go out and raise debt as single B; they would still be able to attract capital. Is that fair? No, not in the slightest.

Q. And that would be because --

A. DR. BOOTH: Because it's not on reasonable terms and because that is not in the long-run interests of either the bondholders, the equity holders, the ratepayers or the people of this province.

Q. Okay. And what I'm just asking you to do, sir, is to focus on not on reasonable terms. As I understood, it was because it would be dilutive to the existing shoulders?

A. DR. BOOTH: That's correct.

Q. And it may or may not impair the financial integrity of the enterprise?

A. DR. BOOTH: That's correct.

Q. And is there any other reason? Or is it just those two?

A. DR. BOOTH: As I said, I mean capital attraction is that it has to be on reasonable terms and the -- normally that's interpreted that you are raising capital on a stock price that's marginally above book value otherwise it's diluted to the common stockholders. You are basically bringing in new investors at a lower price to the company than the existing investors have paid to buy those shares.

Q. Thank you.

MR. SMITH: Mr. Chairman, I was about to move to another somewhat more involved area, if you want I can try and skip a little further through and see if I can pick a couple of quick ones but I would prefer to take a break.

THE CHAIR: What you are suggesting is that we should take our 20-minute break now then and come back at about 10 to 11.

MR. SMITH: Thank you, I would appreciate it.

THE CHAIR: Thank you.

(ADJOURNMENT)

THE CHAIR: The Board is now going to give its ruling on the motion of yesterday, and the Board is

Q. Table 9.

A. DR. BOOTH: Okay, fine. It's page 57 on mine.

THE CHAIR: It's 63 on mine, on the electronic version.

MR. SMITH: And mine as well, sir.

Q. The Chairman and I will be able to follow, we'll let you know as we work through it.

Now Dr. Booth, I don't think you're going to have a lot of difficulty with this. You calculate a 2.15 times interest coverage ratio at a 65/35 debt equity capital structure based on your 8.12 return on common equity, a 6.3 percent cost of debt, and a 40 percent tax rate; is that fair?

A. DR. BOOTH: That's correct.

Q. And you compare the 2.15 times to coverages for the lowest risk regulated companies, those being pipelines; is that fair? This is table 10 and over on the top of the next page, which is my page 64.

A. DR. BOOTH: That's correct. Also, in the case of Foothills, TQM and NGTL, are the ones that are least affected by other activities.

Q. And the comparison is not made with other electric DISCOs or gas LDCs for example, which other things being equal would tend to be riskier; is that fair?

A. DR. BOOTH: That's correct. I think there was an IR question on this why these particular companies, and I explained these came straight from DBRS and the DBRS didn't have any other companies. I think the only other company that they had was Enbridge which I included in the IR response.

Q. And just so that we're clear, you would agree that electric DISCOs and gas LDCs, other things being equal, would be riskier than the pipeline sample?

A. DR. BOOTH: I would agree with that.

Q. Okay. Now we'd like to get into the actual coverages if we might, and Mr. Johnson, I know that you have spoken to this in your opening statement. I will weave you into this discussion but if we can just try to go through it in an orderly way. The actual coverages are based on embedded, not marginal debt cost; is that fair?

A. DR. BOOTH: That's correct.

Q. And that's what S&P and DBRS and other debt investors look at?

A. DR. BOOTH: That's how they calculate the ratios, correct.

Q. Right. Okay. And that would be what equity investors would be concerned with as well, the actual coverages?

A. DR. BOOTH: That's difficult. I'm not quite sure what equity investors look at.

Q. That's fine, sir.

A. DR. BOOTH: They are obviously not as concerned with coverage ratios as are the bond investors.

Q. That's a fair qualification, but of direct concern to the debt investors?

A. DR. BOOTH: Yes.

Q. I'm not sure how to go about this, but what should we use for the actual cost of debt for the ATCO Utilities? You've used 6.3 percent; would you agree that the actual cost of debt for the ATCO Utilities is higher than that?

A. DR. BOOTH: That's correct. I think it's true that almost all utilities, the embedded cost of debt is higher because we've been in a declining interest rate environment for the last 20 years and the embedded debt costs are essentially just a moving average of those corporate bond yields over the time at which they have been funded.

Q. Fair enough.

A. DR. BOOTH: So we have plateaued over the last two or three years. If interest rates start to go up, that moving average of the embedded debt cost may start to go up again.

Q. Mr. Johnson may be looking for the exhibit I was going to refer you to, which is 021-12, which was a response of Mr. Edmondson to an undertaking response to Mr. Brander

6.145 PERCENT REFERRED TO IN
MR. JOHNSON'S OPENING STATEMENT AS WELL
AS THE ACTUAL COST OF DEBT, EMBEDDED
COST OF DEBT AND THE ACTUAL EFFECT OF
TAX RATES

Q. MR. SMITH: Now, Dr. Booth, back to you. On page 65, so two pages on from where we were last, of your evidence, and I'm at the top of the page, lines 2 through 4, it states: "Clearly with the ROE set on the basis of lower interest rates, firms with higher embedded debt costs will see their coverage ratios squeezed." Do you see that?

A. DR. BOOTH: Yes.

Q. And then it states in the first sentence of the next paragraph: "With a lower interest coverage ratio, it is possible that a utility could be downgraded." Right?

A. DR. BOOTH: Correct.

Q. And then a little further on you described that as a market access problem?

A. DR. BOOTH: That's correct.

Q. Which presumably needs to be dealt with?

A. DR. BOOTH: Correct.

Q. And your view of the correct answer to those types of market access problems appears starting at line 17 of the same page, and it continues over, and I'm sorry to do this because I know you have different pages, but it continues over to the top of the next page, my page 66, that says that any problems unique to individual firms can be solved by the use of preferred shares instead of debt in any incremental financing?

A. DR. BOOTH: Correct.

Q. And what I'm focusing on here is "instead of debt." Now you say the correct answer, instead of debt, are retractable preferred shares, right?

A. DR. BOOTH: That would be my suggestion, yes.

Q. I wonder if someone can provide you with a copy of Exhibit -- you'll love this -- 005-19. I believe it's -- well, (e) and (f), appendices C and D. And what this is is the DBRS credit rating report for CUL. This is the one dated October 23rd, 2003. It's attached to the rebuttal evidence. I'll try and put that into something more recognizable. It was attached to the ATCO rebuttal evidence and it was appendix D.

THE CHAIR: Could you repeat those numbers, Mr. Smith?

MR. SMITH: Yes, the ATCO rebuttal evidence, as I appreciate it, sir, is 005-19, and as I understand it, (f) is -- that is 005-19 (f) -- is appendix D.

THE CHAIR: Pardon me. I see where I made the mistake. It's appendix C and D and I was reading it as the subsets (c) and (d). Now I've got it. Okay.

A. MR. JOHNSON: Was that is the CU Inc. or the CUL?

Q. It's the CUL, it's appendix C and D of CUL.

A. DR. BOOTH: Yes, I have it.

Q. And sir, this document, just to be clear, is the DBRS report dated October 23rd, 2003, so it's obviously quite current; is that fair? And what I'd like you to do is just to look over on page 6; are you there?

A. DR. BOOTH: I am.

Q. Financial profile on sensitivity analysis is the table in the middle of page, right?

A. DR. BOOTH: I see it.

Q. Footnote 2 in little print, at the end -- let me read footnote 2, it says:

> "Net of uncommitted cash holdings.
> Cumulative preferred shares,"
> and then the equal sign,
> "70 percent equity weighting,
> retractable preferred-100 percent debt."

A. DR. BOOTH: Yes.

Q. So your answer to this squeeze in interest coverage ratios instead of debt is to use retractable preferred shares which are treated as 100 percent debt?

A. DR. BOOTH: No, the way which -- there is two issues here. One is the accounting treatment of retractable preferred shares; and the other is how the capital markets treat them. And the accounting treatment retractable preferred shares depends upon what they're retractable into, so it depends whether they are what's called soft retractions or hard retractions. A hard retraction is when the preferred share is retractable into cash and a soft retraction is when they are retractable into other preferred shares.

So that preferred shares that have got a hard retraction into cash are generally treated for accounting purposes, they are treated as debt, and soft retractions that are retracted into other preferred shares are treated more as an equity component.

So what you have here are particular type of preferred shares issued by CUL where the retractable ones presumably have a hard retraction where they are retractable into cash at the end of the five-year period. So I'd have to look at the prospectus for those but I would guess that's why they had that accounting treatment.

Q. But you accept that the retractable preferreds currently involved with CUL are 100 percent debt?

A. DR. BOOTH: I would accept that the accounting treatment by DBRS is 100 percent debt, but you have to put this into context. CU doesn't have any access problems; CU has got an A-rated bond rating. What I am talking about is a situation that does not reflect CU's current operations or those of any of the ATCO companies.

The situation I'm envisaging is a situation where a company has a very high embedded cost of debt, perhaps it's a smaller utility where there is one issue of debt outstanding that happens to be an issue five or ten years ago, with a high embedded cost of debt and the formula or current methods of estimating the cost of equity results in a dramatic reduction in the cost of equity and as a result, the interest coverage is squeezed; and there may be a possibility that the firm has access problems. That does not describe Canadian utilities or any of the ATCO companies.

In that circumstance, if the company comes before the Board and says look, we're in serious danger because we have this embedded cost of debt, give us a higher return on equity, my answer to that is that doesn't make any sense because the ratepayers are already paying higher than market cost for the embedded cost of debt and the company is asking for a higher return on equity again being basically -- the ratepayers are paying twice because of an unfortunate issue of debt.

In those circumstances, I would suggest there are other ways of getting around market access problems, such as issuing preferred shares. There are others. Consumers Gas for example -- sorry, Enbridge Gas Distribution Inc. still has outstanding their -- the trust indenture that allows it to issue first mortgage bonds and the last time I asked an information request of them they said we still have it in case we need market access problems, so if we can't issue subordinated debt we are going to issue first mortgage bonds.

So there are other ways of getting around market access problems that may be caused, and I'm not saying they are caused, but may be caused by squeezed interest coverage ratios than giving the equity holders a bonus on their allowed rate of return. It just doesn't make any sense to give the equity holders an extra return simply because there is a high embedded cost of debt.

Q. Sir, the effect of the Calgary recommendations here would be to lower the return on common equity from that which currently prevails for each of the regulated utilities and to thin the overall equity ratio for the utilities; isn't that fair?

A. DR. BOOTH: I think I'm recommending 35 percent for ATCO distribution, 30 percent for ATCO Electric, 42 percent for ATCO Pipe. I think on the gas and the pipe side when you add it all up, it's not too much different from where Canadian Western Natural Gas was before

ATCO unbundled all of the companies.

Q. But the point, sir, directionally, is that the effect of the overall recommendations is to further squeeze the interest coverage ratios?

A. DR. BOOTH: I think it's fair to say -- I don't think my capital structure recommendations have that effect so much as the rate of return recommendations.

Q. Right.

A. DR. BOOTH: Where certainly my rate of return recommendations are lower than the current allowed return for those companies.

Q. And we don't know what the market access would be at the level that you're recommending? We don't --

A. DR. BOOTH: We do know that CU is A-rated which is one of the best bond ratings of any regulated utilities; and traditionally that's been because of the very high component of preferred shares in the capital structure; and traditionally that was because of the Public Utility -- Public Utility Income Tax Transfer Act.

Q. P-U-I-T-T-A.

A. DR. BOOTH: So traditionally there was that historical anachronism that the preferred share component for the most significant Alberta utilities, the TransAlta and the Canadian utilities, resulted in very much higher bond ratings than were the norm across Canada as a whole simply because of this special tax feature; and as that special tax feature unwinds and those preferred shares are replaced with debt and common equity, we would expect the coverage ratios to go down and we would expect their bond ratings to go down, and I'm surprised, to be honest, that the bond rating is still an A. I would expect it to be similar to that of other regulated Canadian utilities.

Q. And they certainly would go down if your recommendation on ROE and capital structure were accepted; is that fair?

A. DR. BOOTH: No, I don't make any predictions on bond ratings, I'm not a bond rating analyst.

Q. Thank you, sir.

A. DR. BOOTH: I would go so far as to say that I don't think they will go up.

Q. If we could shift to another subject, Dr. Booth --

A. MR. JOHNSON: If you're going to switch, Mr. Smith, just one comment. Whether the preferred shares are treated as debt or equity for purposes of capital structure, they would still provide some potential benefit in the interest coverage calculation.

Q. Would you care to identify how?

A. MR. JOHNSON: Well, because you're still, for a preferred share, you are getting a tax component with respect to it. So that, plus -- as I understand it, it would not be treated, necessarily, as interest expense but even if it was, the yield on those preferred equities would be lower than the debt cost.

Q. I guess that would depend on how those preferreds are rated, right?

A. MR. JOHNSON: Obviously all those factors. But normally a preferred share would have a lower yield than a debt of equivalent -- an equivalent company.

Q. Right.

A. MR. JOHNSON: So when you take that yield and gross it up for the tax and then divide it by that yield, you are going to get a higher number, and a boost to your interest coverage.

Q. But you're not disagreeing with Dr. Booth that in response to squeezed interest coverage ratios, that you need to find solutions instead of additional debt?

A. MR. JOHNSON: But he's given a suggestion here that if you can't raise debt at reasonable terms one of the alternatives is -- one of the lower-cost alternatives is to use preferred shares.

Q. Retractable preferred shares?

A. MR. JOHNSON: Yes.

A. DR. BOOTH: Term preferred shares, five-year preferred shares, that's fine.

But also, Mr. Smith --

Q. You threw in a couple of new ones there, sir. You said in your evidence retractable preferred shares. Maybe I misheard you. What did you say?

A. DR. BOOTH: No, the idea was if there is -- if you've got a big amount of high embedded debt, sooner or later that's going to run off. Sooner or later it's going to be refunded. So if you look at the term of a regulated utilities' debt and suppose they've still got some 18 percent debt outstanding from 1982 when we had horrendously high interest rates in Canada, and I would expect all of that's run off, but just suppose there is a very high amount, high coupon debt that's outstanding, and that's currently squeezing the interest coverage ratios but that's going to run off in two to three years' time. I wouldn't recommend that the Board sanction 5 percent extra component of traditional fixed -- infinite maturity debt preferred shares.

In that situation, I would recommend that they issue some form of retractable preferred shares or some form of five-year term preferred shares until the debt comes due and is refunded at current market rates. Sooner or later all high coupon embedded debt gets refunded, and if there is a market access problem because some high coupon debt is going to come due in two or three years' time, you need a two- or three-year solution. So that was the context of --

Q. What was it that Keynes said about the long-term, sir?

A. DR. BOOTH: We're all dead.

Q. As the debt rate drops -- I'm sorry, sir --

A. DR. BOOTH: I'm impressed, Mr. Smith.

Q. Thank you. I can tell you a little about Lord Calder as well if you want.

If we have a deterioration in the debt rating as a result of your recommendation, I'm putting to you a hypothetical, what do you think that would do to the rating for the retractable preferred shares or preferred shares generally?

I mentioned this to Mr. Johnson, but I'd like to get your reaction. Would it not be fair to expect that if you had a downgrade of the debt and you were then having to solve part of the problem with access to retractable preferred shares, wouldn't they become somewhat more expensive or more difficult to access?

A. DR. BOOTH: No, not necessarily. It is true that when you look at bond ratings, the DBRS or S&P will go in and they will look at the financial health of the company's business risk, everything else, all the ratios and they will assign different ratings for different classes of securities; and traditionally, for example, we could have a commercial paper rating that was totally different from the long-term bond rating.

And the classic example of that was INCO, which is the nickel producer and its earnings are very very tied in with the price of nickel; and I remember -- I think this was the early 1990s -- the price of nickel was very very high. It was flush with cash. Its commercial paper rating was R-1 mid, which I think it was R-1 mid, a very very high commercial paper rating, at the same time its long-term bond rating was double B -- well, it was much much lower.

And the reason for that is the bond rating agencies recognize that as a cyclical company, long-term prognosis wasn't very good. Its short-term prognosis was very good and that was reflected in its ratings.

So when you look at the rating agencies, they will tell you over and over again they don't rate companies; they rate issues. And commercial paper issue may have a different rating than a long-term bond issue, an unsecured debenture issue will have a different rating from a mortgage bond issue, and the preferred shares will have a different rating. It depends upon the characteristics of the company.

Q. Can you tell me of one company with a triple B debt rating and a P1 preferred share rating?

A. DR. BOOTH: I just told you INCO.

Q. P1, today.

A. DR. BOOTH: I haven't done the analysis, and that's not something I would look at, but all I'm saying is there are differences in these ratings.

Q. And what about a utility, sir, a triple B rating with a P1 preferred share rating?

A. DR. BOOTH: Generally you wouldn't. I mean, that's like asking for triple A bond rating, and if we look at the structure of the bond market, pretty much the only triple A issues in Canada are either subsidiaries of major foreign corporations where they've got triple A ratings, or they are structured financing. There is some form of securitized debt issue.

There is a precious few triple A bond rating companies. The last time I looked, which was several years ago, the only one was a Bell Canada mortgage bond that was still outstanding, but there are very few triple A corporate issues. They are nearly all securitized debt financings, which means their credit card receivables are floated off in the capital markets.

Q. May I have just a moment, sir. Other things being equal, if there were pressure building on the interest coverage ratios from the standpoint of the debt market, would you expect some deterioration in the rating of the preferred shares as well or even in advance of the debt?

A. DR. BOOTH: It has to come down to why there is pressure on the interest coverage ratios. For example --

I don't want to go back in cycles here, but we are in a declining income tax environment in Canada. We've had a Federal Government that has systematically reduced corporate income taxes to make corporate Canada more competitive with the United States.

Now, one impact of that is that we are seeing declining interest coverage ratios simply because the tax component has gone down.

So if you ask me do I think the bond rating agencies will lower bond rating simply because companies aren't paying as much in corporate income tax, my answer would be no, it doesn't make any sense that a company's bonds are somehow riskier simply because it's more competitive and it's not paying as much in tax.

And in the extreme example, if we remove the corporate income tax burden completely, coverage ratios will absolutely go down. Does that mean to say that debt is more risky because the company can charge lower prices because it hasn't got a huge cost in income taxes? My answer to that is no.

That's why, in fact, a lot of the rating agencies, DBRS in particular, used to calculate what they called after-tax coverage ratios which was basically adjusting for utilities for the tax component on the basis that the only dollar in the revenue requirement to cover a dollar of interest is the dollar of interest.

Q. But we can agree, I take it, that downgrades of either debt or preferred shares would be a result of concerns about interest coverage ratios deteriorating?

A. DR. BOOTH: Bond ratings are always a cause for concern, and in terms of what goes on in the hearing room, I always look at the bond rating agencies' reports. I also try and look at equity analyst reports. A bond downgrade is not something to be taken lightly.

Q. And that's fine.

A. DR. BOOTH: In terms of what happens for a company, traditionally in Canada we have had more bond rating sensitive investors than in the United States. In fact, up until ten years or so ago, getting below an A minus bond rating for a normal industrial company caused problems because lots of institutional investors in Canada would not invest in triple B-rated nonindustrials. They would invest in triple B-rated utilities, but there wasn't much of a triple B bond market in Canada. And when you got down to double B, it almost didn't exist at all. A lot of Canadian companies, particularly in the oil and gas sector, went to the United States for lower rated debt.

We have seen an emergence, and Mr. Lackenbauer referred to this, as more triple B and noninvestment grade investors in Canada buying those types of debt. So ten or fifteen years ago I would have been a lot more concerned about a bond rating downgrade than I am now. It's still a matter of serious concern, but it is not quite the concern in terms of market access that it was 10 or 15 years ago.

Q. Thank you. I believe about 15 minutes ago I tried to move to another area, sir. Is it okay, Mr. Johnson?

I'd like to just go into the theoretical basis of your recommendation for a bit, Dr. Booth, and I believe this was touched upon earlier. As I understand it, you believe that CAPM should not be used as the sole test to provide a fair return?

A. DR. BOOTH: I think the more estimates you have, then the more comfortable you can be with the recommendation. So I would like nothing better than to present to this Board more tests than I've actually presented.

Q. And the reasons why CAPM on its own would not necessarily be as reliable as you'd like would be why?

A. DR. BOOTH: There is, as I discussed earlier, there is instability in betas, and it's one thing my looking at the economic record and saying this is why this beta has changed and if I make this adjustment, I think it's a correct estimate for the future risk; but the fact is people who look at the betas and if they don't understand

TAB 5

Decision 2004-052

Generic Cost of Capital

AltaGas Utilities Inc.
AltaLink Management Ltd.
ATCO Electric Ltd. (Distribution)
ATCO Electric Ltd. (Transmission)
ATCO Gas
ATCO Pipelines
ENMAX Power Corporation (Distribution)
EPCOR Distribution Inc.
EPCOR Transmission Inc.
FortisAlberta (formerly Aquila Networks)
NOVA Gas Transmission Ltd.

July 2, 2004

Alberta Energy and Utilities Board

ALBERTA ENERGY AND UTILITIES BOARD
Decision 2004-052: Generic Cost of Capital
AltaGas Utilities Inc.
AltaLink Management Ltd
ATCO Electric Ltd. (Distribution)
ATCO Electric Ltd. (Transmission)
ATCO Gas
ATCO Pipelines
ENMAX Power Corporation (Distribution)
EPCOR Distribution Inc.
EPCOR Transmission Inc.
FortisAlberta (formerly Aquila Networks)
NOVA Gas Transmission Ltd.
Application No. 1271597

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5 CAPITAL STRUCTURE

5.1 Introduction

The Board notes that the capital structures determined in this Proceeding are premised on the business risks that existed at the time of the Proceeding.

For the convenience of readers, the following table (ordered by sector) compares the equity ratios that were last approved by the Board with the equity ratios recommended by the Applicants, CG and Calgary/CAPP:

Table 8. Recommended Equity Ratios vs. Last Board Approved Equity Ratios

	Last Board-Approved (%)	Recommended by Applicant (%)	Recommended by CG (%)	Recommended by Calgary/CAPP (%)
Electric and Gas Transmission				
ATCO Electric TFO	32.0	38.0	30.0	30.0
AltaLink	34.0[4]	37.5	30.0	32.0
EPCOR TFO	35.0	40.0	30.0	35.0
NGTL	32.0	40.0	32.0	33.0
ATCO Pipelines	43.5	50.0[3]	40.0	38.0
Electric and Gas Distribution				
Aquila	N/A [1]	42.5	35.0	35.0
ATCO Electric DISCO	35.0	45.0[2] (+ 5-10 %)	35.0	35.0
ENMAX DISCO	N/A [5]	50.0	35.0	40.0
EPCOR DISCO	N/A [5]	45.0	35.0	40.0
ATCO Gas	37.0	40.0	37.0	35.0
AltaGas	41.0	45.0	40.0	35.0

[1] The Board did not specifically approve this ratio; it was part of a negotiated settlement approved in Decision 2003-019, which included a deemed 40% equity ratio as one of many settled parameters of the revenue requirement.

[2] ATCO Electric DISCO requested a further increase of 5-10%, beyond its original request of 45%, in its equity ratio to account for ATCO's perception of additional business risks resulting from the *RDS Amendment Regulation.*[82]

[3] ATCO Pipelines, in addition to a 50.0% equity ratio, also proposed a 0.5% addition to ROE.

[4] In Decision 2003-061, the Board approved an equity ratio for AltaLink of 32%, plus an additional 2% to offset the impact on the interest coverage ratio of a partial allowance of income taxes in the revenue requirement.

[5] ENMAX and EPCOR Distribution were subject to Board jurisdiction effective January 1, 2004.

The Board notes that, with the exception of CGA, the interveners who did not sponsor expert evidence generally supported the views of CG and Calgary/CAPP in argument. The Board also notes that the Applicants did not generally take a position on the appropriate capital structures for other Applicants.

In the Board's view, setting an appropriate equity ratio is a subjective exercise that involves the assessment of several factors and the observation of past experience. The assessment of the level of business risk of the utilities is also a subjective concept. Consequently, the Board considers that there is no single accepted mathematical way to make a determination of equity ratio based on a given level of business risk.

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[82] *Regulated Default Supply Amendment Regulation* (AR 323/2003)

To determine the appropriate equity ratio for each Applicant, the Board will consider the evidence and, where applicable, the experts' views and rationales in each of the following topic areas:

1. The business risk of each utility sector and Applicant;
2. The Board's last-approved equity ratio for each Applicant (where applicable);
3. Comparable awards by regulators in other jurisdictions;
4. Interest coverage ratio analysis; and
5. Bond rating analysis.

The Board notes the general consensus that the electric and gas transmission sectors had the least risk of all Applicants in this Proceeding. Further, the Board notes that no party argued otherwise.

The Board will first consider the appropriate capital structures for the electric and gas transmission Applicants, and the Board will subsequently consider the appropriate capital structures for the electric and gas distribution Applicants.

5.2 Electric and Gas Transmission

The Board notes from the above Table 8 that for the taxable electric transmission companies,[83] the Applicants proposed equity ratios of 37.5 and 38.0%, whereas the interveners proposed an equity ratio of 30.0%.

With respect to transmission companies that are not fully taxable, the Board will provide its findings later in this Decision.

With respect to gas transmission, NGTL proposed an equity ratio of 40%, while the interveners proposed 32 and 33%. The equity ratios proposed by all submitting parties for ATCO Pipelines were materially higher than the equity ratios each proposed for NGTL. The Board will address ATCO Pipelines later in this Decision.

Business Risk

The Board notes that the Companies[84] compared the risks of electric transmission companies with the risks of NGTL as they existed in 1995. Dr. Evans (sponsored by the Companies) considered that electric transmission companies have more risk today than NGTL had at the time NGTL's equity ratio was last approved, for 1995.[85]

However, the Board considers that because it now has evidence regarding all Applicants' current risks, the utilities should be compared based on the business risks that existed at the time of this Proceeding. This was the approach of the experts other than Dr. Evans.

ATCO submitted that electric transmission companies were more risky than NGTL, principally due to the smaller size of the electric transmission companies relative to NGTL, the higher expected growth rates of the electric transmission companies relative to NGTL, and ATCO's

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[83] In this Proceeding, AltaLink assumed it was fully taxable, but the Board did not.

[84] Companies Argument, page 96

[85] Companies Argument, page 98

perception of a greater degree of regulatory uncertainty for the electric transmission companies relative to NGTL.

Although NGTL did not compare its level of business risk to that of other utilities, it did submit extensive evidence with respect to its own business risks, including operating expense risk, supply risk, competition risk, volume risk and credit risk.

Calgary/CAPP[86] and CG[87] each considered NGTL to have higher short and long-term business risk than the electric transmission companies, because NGTL faces operating expense risk, supply risk, competition risk, volume risk and credit risk, whereas the electric transmission companies only face operating expense risk. The interveners[88] viewed TFO growth prospects as an opportunity rather than a risk.

The Board agrees with the interveners that NGTL has a higher short-term business risk than the electric transmission companies, principally due to higher competition and credit risks. The Board also considers that NGTL potentially faces higher long-term risks due to supply risk although, in the Board's view, the bulk of that risk, if it materializes, will likely be identified early enough for NGTL to apply to the Board for potential adjustments to throughput forecasts and/or depreciation rates.

The Board also notes that NGTL does not have the same revenue certainty, as do the electric transmission companies. The Board also considers the higher expected growth rates of the electric transmission companies to be an opportunity for the TFO shareholders to increase their investments, and not fundamentally a matter of increased risk. The Board notes that utilities are allowed a return on funds used during construction. In addition, the Board was not persuaded that electric transmission companies have a greater degree of regulatory uncertainty than gas transmission companies.

The electric transmission companies have a single customer, the AESO. The Board considers the AESO to be of minimal credit risk. Further, the Board notes that the AESO pays the electric transmission companies 1/12 of their approved revenue requirement on a monthly basis with no adjustment for changes in demand or supply of electricity carried by the TFO.

For all of the above reasons, the Board does not agree with ATCO and the Companies that the electric transmission companies are more risky than NGTL.

The Board concludes that taxable electric transmission companies have the lowest business risk of any utility sector regulated by the Board, and that the risks of NGTL are somewhat higher than the risks of a fully taxable electric TFO.

The Board notes, from the above Table 8, that CG's and Calgary/CAPP's recommended equity ratios for NGTL were 2% and 3%, respectively, higher than their recommended equity ratio for a fully-taxable electric TFO. The Board also notes that NGTL did not provide the Board with an indication of its views respecting its risks relative to electric transmission companies, and, more particularly, did not indicate a view on an appropriate equity ratio differential compared to electric transmission companies.

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[86] CAPP/Calgary Argument, page 56

[87] CG Argument, pages 67-70

[88] CG Argument, page 70; Calgary/CAPP Argument, pages 67-70

The Board considers that business risk, in isolation, would indicate an equity ratio for NGTL that is 2-3 % higher than the equity ratio for a fully taxable TFO.

Comparison to Previous Board Awards

The Board notes that the last Board-approved equity ratio for NGTL of 32% was established for 1995.[89] The Board agrees with the general view of the experts that the business risks of NGTL have increased since 1995, principally due to a potentially higher supply risk and a higher competition risk.

Directionally, the Board concludes that NGTL's higher business risk, in isolation, supports an equity ratio for NGTL higher than 32%.

In Decision U99099, the Board established an equity ratio for electric transmission companies (TFOs) of 35%. In Dr. Evan's view,[90] the risks of electric TFOs have not changed since the time of Decision U99099, which would indicate that no change in equity ratio was appropriate. However, the Board considers that the risks of electric transmission companies have likely decreased since the time of Decision U99099 due to increased clarity of the role of the TFO, increased clarity with respect to the AESO's role and structure, the resolution of liability issues and the changes in transmission policy including the role of competitive bidding.

Directionally, the Board considers that this factor, in isolation, supports an equity ratio for fully taxable electric transmission companies lower than the 35% determined in Decision U99099.

The Board notes the last approved equity ratio for ATCO Electric TFO was 32% and for AltaLink was 34% (32% + 2% for the interest coverage ratio adjustment). However, these ratios were established when NGTL's award was 32%.

Directionally, the Board considers that this factor, in isolation, supports an equity ratio for fully taxable electric transmission companies similar to the last award of 32% or marginally higher.

Comparable Awards by Regulators in Other Jurisdictions

The Board acknowledges the potential for circularity when considering awards by other regulators. The Board also recognizes that business risks may be quite different in other jurisdictions. The Board has discussed some of these differences in the ROE section of this Decision and will provide further comment in following sections of this Decision. Nevertheless, the Board considers that comparable awards by other regulators may provide some indication of the appropriate capital structures for the Applicants.

As a result of the electric industry restructuring in Alberta, the Board notes that there are no TFO entities in the other provinces of Canada that are directly comparable to TFO entities in Alberta. However, in the Board's view, Canadian federally regulated natural gas transmission pipelines are of some assistance in drawing comparisons to both NGTL and the taxable electric transmission companies.

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[89] U96001, Nova Gas Transmission Ltd., 1995 General Rate Application, Phase 1

[90] Companies Argument, page 110

The Board considers that the nature of NGTL as a gathering system, with numerous receipt and delivery points, a diverse customer base, and other related factors demonstrates an additional degree of business risk for NGTL when compared to the TCPL Mainline. However, the breadth of NGTL's diverse customer base mitigates the additional risk to a large degree, since the loss of any one customer or point of supply would likely not be material to the long-term risks faced by NGTL. The Board notes that in RH-4-2001, dated June 2002, the NEB awarded TCPL's Mainline a 33% common equity ratio based on its conclusion that "the level of business risk facing the Mainline has increased since 1995…".[91] The NEB cited "increases in the risks resulting from pipe-on-pipe competition and increased supply risk but noted, "other sources of risk have not changed materially".[92]

The Board notes that NGTL's last awarded equity ratio of 32% for 1995 was 2% higher than the contemporaneous NEB award of 30% for TCPL's Mainline. The Board notes that the same 2% differential if applied today would result in an equity ratio of 35% for NGTL. The Board considers that this factor, in isolation, supports an equity ratio of 35% for NGTL.

Since the Board considers electric transmission companies to have less risk than NGTL, the Board considers that this factor, in isolation, supports an equity ratio of less than 35% for taxable electric transmission companies.

The Board notes Dr. Evan's evidence,[93] provided at the Board's request, that the awarded equity ratios for the Foothills, ANG and TQM pipelines remain at the 30% level that the NEB established in 1995.

However, the Board notes the NEB's view[94] that Foothills and ANG operated on a lower risk monthly cost of service basis, and that TQM had a high degree of assurance that its costs would be recovered. For these reasons, the Board considers the risks of the taxable electric transmission companies and NGTL are somewhat higher than the risks of Foothills, ANG and TQM. Consequently, the Board considers that this factor, in isolation, supports an equity ratio of more than 30% for both the taxable electric transmission companies and NGTL.

The Board notes that the awarded equity ratio of the Westcoast Energy pipeline remains at 35%, which was set by the NEB in 1995. The Board also notes the NEB's view[95] that Westcoast had higher risks due to the nature of its gathering system and processing plants and due to the hydrogen sulfide content of the gas it transports. For these reasons, the Board considers the risks of taxable electric transmission companies to be lower than the risks of Westcoast and the Board considers the risks of a large gathering system like NGTL to be more similar to Westcoast than to the electric transmission companies. Consequently, the Board considers that this factor, in isolation, supports an equity ratio of approximately 35% for NGTL and less than 35% for the taxable electric transmission companies. However, the Board would note that there are also differences between Westcoast and NGTL.

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[91] RH-4-2001, page 58

[92] RH-4-2001, page 28

[93] Exhibit 021-24

[94] RH-2-94, page 26

[95] RH-2-94, page 25

Interest Coverage Ratio Analysis

The Board notes that S&P provides guideline interest coverage ratios,[96] corresponding to various corporate credit ratings, for utilities of various business risk profiles (risk ranking levels). The Board further notes ATCO's evidence[97] that the estimated S&P risk ranking for ATCO Electric transmission is "2" and that the actual S&P business risk profile ranking for NGTL is "3".

The S&P guidelines indicate that for a utility with a risk ranking of "2", a pretax interest coverage ratio in the range of 2.3 to 2.9 times is indicated for an "A" debt rating.

The Board notes that S&P does not rigorously apply its guidelines with respect to each specific financial ratio. In addition to interest coverage ratios, S&P reviews a number of other key financial ratios, as well as many diverse and often subjective factors, in order to arrive at a specific credit rating for an individual utility.

The Board notes that Enbridge Gas has been assigned a risk ranking of "2", which would imply that electric and gas transmission companies, which are less risky, could be considered to be ranked at less than "2".

The Board does not have a target credit rating for utilities under its jurisdiction. The Board is of the view, however, based on the evidence before it in this Proceeding, that interest coverage ratios and credit ratings are important considerations in assessing the appropriate capital structure. However, the Board considers that the foregoing are just one set of factors to consider.

The Board notes that DBRS has indicated, in its NGTL credit rating report,[98] that an interest coverage ratio "above 2 times ... is acceptable for a regulated cost of service-based business".[99] The Board notes that the DBRS report, "Methodologies in Rating Utilities", dated June 2002,[100] indicates a fixed-charge coverage ratio of 1.5 for a DBRS debt rating from BBB to A. The report's definition of fixed-charge coverage, in cases where preferred shares do not exist, is the same as the definition of interest coverage that the Board has used throughout this Decision. The Board notes the apparent inconsistency in the two statements, but considers that taken together, a conclusion can be drawn that an interest coverage ratio near 2 times might be appropriate for low risk regulated entities. The Board also notes Dr. Booth's (sponsored by Calgary/CAPP) evidence that an interest coverage ratio of 2.15 times is reasonable for pipelines, considering their historic actual levels.[101]

The Board notes that some parties have expressed a concern that the acceptable equity ratios for regulated utilities in Alberta could potentially be overstated,[102] if the S&P guidelines with respect to interest coverage ratios were applied in a mechanical manner without consideration of other factors.

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[96] Exhibit 008-02, pre-filed Information Response AUMA-AP-11

[97] Exhibit 005-11-1, Capital Structures for the ATCO Utilities, Kathleen McShane, pages 9-11

[98] Exhibit 013-17, DBRS credit rating report on NGTL, dated June 26, 2002, page 1

[99] Exhibit 013-17, page 9 of 35

[100] Exhibit 008-02, pre-filed Information Response CAL-AP-8

[101] Exhibit 016-11(a), Evidence of L.D. Booth, page 63

[102] Calgary/CAPP Argument, page 28

The Board has calculated the pretax interest coverage ratios that would result for a utility, with no preferred shares, using a 2004 tax rate of 33.87%,[103] using the ROE that the Board determined in this Decision of 9.6%, and applying a range of equity ratios and embedded debt costs. The Board will use the following table as one of several tests to evaluate and determine the appropriate common equity ratios.

The interest coverage ratio results for a range of equity ratios and embedded debt costs are as follows:

Table 9. Pretax Interest Coverage Ratios at Varying Embedded Debt Costs

Equity	Embedded Debt Cost					
Ratio	6.0%	6.5%	7.0%	7.5%	8.0%	8.5%
30.0%	2.0	2.0	1.9	1.8	1.8	1.7
31.0%	2.1	2.0	1.9	1.9	1.8	1.8
32.0%	2.1	2.1	2.0	1.9	1.9	1.8
33.0%	2.2	2.1	2.0	2.0	1.9	1.8
34.0%	2.3	2.2	2.1	2.0	1.9	1.9
35.0%	2.3	2.2	2.1	2.0	2.0	1.9
36.0%	2.4	2.3	2.2	2.1	2.0	2.0
37.0%	2.4	2.3	2.2	2.1	2.1	2.0
38.0%	2.5	2.4	2.3	2.2	2.1	2.0
39.0%	2.6	2.4	2.3	2.2	2.2	2.1
40.0%	2.6	2.5	2.4	2.3	2.2	2.1
41.0%	2.7	2.6	2.4	2.3	2.3	2.2
42.0%	2.8	2.6	2.5	2.4	2.3	2.2
43.0%	2.8	2.7	2.6	2.5	2.4	2.3
44.0%	2.9	2.7	2.6	2.5	2.4	2.3
45.0%	3.0	2.8	2.7	2.6	2.5	2.4

The above table shows the results of the mathematical calculations. The Board understands that bond ratings do not rely solely on precise mathematical results. Bond ratings incorporate a variety of factors, including the use of judgment.

The Board cautions readers not to interpret the level of precision expressed in the above table to be absolute in arriving at the appropriate equity ratio.

The Board is aware that some companies have higher embedded debt costs but these embedded debt costs are expected to decline as older, higher-cost debt is retired. The Board also notes that the embedded debt cost for AltaLink is lower than 6%, but that this embedded cost of debt could be understated since AltaLink's long-term financing does not appear to be fully in place.

The Board did not use the above table in a precise mathematical manner. Rather, the Board evaluates the data in the table above by looking at ranges, various company situations, longer-term effects, impacts of declining embedded costs, stability of capital structure awards as embedded debt costs change, and the consideration of other factors that are discussed in this Decision.

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[103] 21% Federal rate, 1.12% surtax and 11.75% provincial tax (12.5% through March 31, 11.5% thereafter)

The Board further considers that all of these differing ratios are merely indicators in arriving at a level of coverage that is considered comfortable and acceptable.

Accordingly, based on the evidence and the above discussion, the Board concludes that an acceptable pretax interest coverage ratio for electric and gas transmission companies, in isolation, is near 2 times.

The Board considers that interest coverage ratio analysis, in isolation, supports equity ratios for taxable electric transmission companies and gas transmission companies greater than the currently approved equity ratios of 32% for ATCO Electric and NGTL.

The Board considers gas transmission companies to have slightly more risk than electric transmission companies and, therefore, the Board considers that this factor, in isolation, indicates that gas transmission companies should have slightly more equity than electric transmission companies.

Bond Rating Analysis

As noted above, the Board does not have a target credit rating for utilities under its jurisdiction. Further, the Board has discussed bond ratings, earlier in this Decision, in the context of the interest coverage ratios. Bond ratings are another factor in determining an appropriate capital structure.

With respect to the indications provided by actual bond ratings, Dr. Evans provided, at the Board's request, a detailed compilation of comparable equity ratios and bond ratings. The following table is an excerpt from that compilation, showing the awarded and the adjusted actual equity ratios for each utility regulated by the Board that has its own bond rating:

Table 10. Equity Ratios and Bond Ratings

	Last Board Awarded Equity (%)	Adjusted Actual Equity[104] (%)	DBRS credit rating[105] and deemed equity ratio at the same date (%)		S&P credit ranking and common equity ratio at the same date (%)	
AltaLink L.P.	34	38.3	A (high)	34.0[106]	A-	35 – 40 implied[107]
EPCOR Transmission	35	37	BBB (high)[108]	35.7[109]		
NGTL	32.2+0.3 preferred	40.3	A	38.9[110]	A-	36.0[111]
Aquila	40 (settlement)	41.9	A (low)	45.5 / 40.0[112]		

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[104] Exhibit 021-24 Dr. Evans calculated the most recently available Adjusted Actual Equity by treating short-term debt as debt, and by treating preferred shares and subordinated debt as 80% equity, consistent with the treatment described at page 106 of Decision 2003-061.

[105] Source: Dr. Evans, Exhibit 021-24

[106] Exhibit 021-45, AltaLink DBRS credit report, dated September 26, 2004, page 6

[107] Exhibit 003-02-6, AltaLink S&P credit report dated May 16, 2003, page 4, indicates expected allowed equity of 35% and actual debt at 60-65% (implies actual equity of 35 to 40%).

[108] Exhibit 012-03-h, DBRS letter regarding EPCOR Transmission Inc.'s indicative bond rating dated June 19, 2002

[109] Exhibit 012-03-b, EPCOR Transmission Inc. Cost of Capital

[110] Exhibit 021-43(c), beginning page 21 of 52, DBRS report on NGTL dated October 17, 2003, page 5

[111] Exhibit 013-17, page 23 of 25, S&P report on NGTL dated June 19, 2003, page 3

Regarding EPCOR Transmission, the Board notes that the DBRS rating in the above table was only an indicative DBRS rating of BBB (high)[113] if DBRS had rated EPCOR in 2002, assuming no debt guarantee from the parent. The DBRS rating indication did not show the equity ratio used. However, the Board notes that an equity level of 35.7% for EPCOR Transmission was applicable[114] at the time that DBRS determined their bond rating to be BBB (high). The Board notes that the cost of debt has been declining since 2002[115] and as a result, the bond rating for a given equity ratio should improve as debt reaches maturity and is replaced. Consequently, the Board considers that this factor, in isolation, indicates that the equity ratio for EPCOR Transmission should be approximately 36%.

From the above table, the Board notes that AltaLink had DBRS and S&P credit ratings of A (high) and A- based on an equity ratio of 34% and a projected equity ratio of 35 to 40%, respectively. Furthermore, the Board notes that AltaLink has a substantial amount of goodwill on its books,[116] amounting to approximately 19% of its assets, which would require incremental equity support, compared to a TFO without goodwill. Consequently, the Board considers that this factor, in isolation, supports an equity ratio for AltaLink, based on rate base, somewhat below 34%.

The Board notes that NGTL has DBRS and S&P credit ratings of A and A- based on equity ratios of 38.9 and 36.0% respectively. In addition, the Board notes that the DBRS credit rating[117] of NGTL is partly based on its parent, TCPL. However, the Board notes that the S&P report[118] indicates that the credit rating is effectively that of TCPL, rather than that of NGTL itself. Therefore, in the Board's view, the adjusted actual equity ratio of NGTL may not be indicative of its required equity ratio, on a standalone basis.

Conclusion

At the beginning of this section, the Board indicated that it would consider a variety of factors for the electric and gas transmission companies.

As discussed in the preceding sections, in the Board's view, setting an appropriate equity ratio is a subjective exercise that involves the assessment of several factors and the observation of past experience. The assessment of the level of business risk of the utilities is also a subjective concept. Consequently, the Board considers that there is no single accepted mathematical way to make a determination of equity ratio based on a given level of business risk.

The following table summarizes the indicated equity ratios that arise from various factors as discussed in the earlier sections.

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[112] Exhibit 004-12, DBRS Report on Aquila, page 5, indicating 54.5% net debt at March 31, 2002 (implies 45.5% equity), and indicating 40.0% deemed equity at December 31, 2001

[113] Exhibit 012-03-h, DBRS letter regarding EPCOR Transmission Inc.'s indicative bond rating dated June 19, 2002

[114] Exhibit 012-03

[115] Ibid.

[116] Exhibit 021-45, AltaLink DBRS credit report, dated September 26, 2004, page 6

[117] Exhibit 021-43(c), page 21 of 52, DBRS report on NGTL dated October 17, 2003, page 1

[118] Exhibit 013-17, page 23 of 25, S&P report on NGTL dated June 19, 2003, page 1

Table 11. Indicated Common Equity Ratios for Transmission Companies By Factor

Factor	Indicated Electric Transmission	Indicated Gas Transmission
Business Risk	Lowest	TFO + 2-3%
Previous Board Awards	>32%, <35%	>32%
Awards in Other Jurisdictions	>30%, <35%	~35%
Interest Coverage Ratio Analysis	>32%	>32%, >TFOs
Bond Rating Analysis	EPCOR ~36% AltaLink <34%	May not be indicative

After considering all of the above factors and after applying its judgment, the Board concludes that an appropriate common equity ratio for fully taxable electric transmission companies, with no preferred shares, is 33.0% and that an appropriate common equity ratio for gas transmission companies is 35.0%.

The Board will now consider each electric and gas transmission Applicant, individually.

5.2.1 ATCO Electric Transmission

The Board considers that ATCO Electric Transmission does not have any material differences in business risk from the typical TFO.

The Board also notes that ATCO Electric Transmission has preferred shares in its capital structure. Although the preferred shares provide additional support to the capital structure, in this analysis, the Board has evaluated the appropriate common equity ratio as if the company had no support from its preferred shares.

For the same reasons that were provided above, the Board concludes that an appropriate common equity ratio for ATCO Electric Transmission, a fully taxable TFO, is 33.0%.

The Board will further address the issue of ATCO's preferred shares later in this Decision.

5.2.2 EPCOR Transmission

The Board considers that EPCOR Transmission does not have any material differences in business risk from the typical TFO.

The Board therefore considers that any difference between the equity ratio for a fully-taxable electric TFO with no preferred shares and the equity ratio for EPCOR Transmission should only reflect the fact that EPCOR Transmission does not have any allowance for income taxes in its approved revenue requirement.

Dr. Evans (sponsored by the Companies, including EPCOR Transmission) recommended that non-taxable utilities be allowed an extra 2.5% equity. Dr. Evans argued that this additional equity component was warranted due to the generally lower interest coverage ratios and the greater variability of net income for non-taxable utilities.[119]

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[119] Companies Argument, page 94

For similar reasons, Calgary/CAPP recommended that non-taxable entities be allowed an extra 5% equity.[120]

ENMAX argued[121] that its non-taxable status justified an additional 8% equity, based on the precedent established by the Board for AltaLink in Decision 2003-061.

All other parties who took a position, on the issue of non-taxable utilities, were of the view that no allowance for additional equity should be provided for non-taxable entities, principally due to a perceived offsetting benefit of lower, more competitive rates. ATCO argued that such an increment to the equity ratio would provide an inappropriate competitive advantage to non-taxable entities.

The Board agrees that a non-taxable entity has a higher volatility of earnings than an otherwise equivalent taxable company, arising from the lack of an income tax component in its forecast revenue requirement. The Board notes that there was no disagreement that the absence of taxation, while lowering costs, increases the volatility of earnings.

In the Board's view, arguments regarding the competitive advantage of non-taxable entities do not have persuasive merit in the context of regulated electric utilities, which do not compete with each other.

However, the Board is not persuaded that the higher volatility of earnings warrants an increase in the equity ratio as high as recommended above. The Board considers that an extra 2% equity would appropriately account for the higher business risks and earnings volatility of a non-taxable entity.

Adding the 2% increment to the 33% equity ratio determined above for a fully taxable TFO, the Board concludes that an appropriate common equity ratio for EPCOR Transmission is 35.0%.

5.2.3 AltaLink

The Board considers that AltaLink does not have any material differences in business risk from the typical TFO.

The Board therefore considers that any difference between the equity ratio for a fully-taxable TFO with no preferred shares and the equity ratio for AltaLink should only reflect the differences in the amount of income taxes included in the respective revenue requirements.

The Board notes that in Decision 2003-061, the Board allowed an additional 2% on the equity ratio to recognize the disallowance of 25% of the requested income taxes, bringing the total common equity component to 34%. The additional 2% equity was intended to maintain the same interest coverage ratio as if there had been no disallowance of income taxes. The Board recognizes that a review and variance application with respect to Decision 2003-061 is pending.

The Board notes the adjustment to AltaLink's equity ratio was intended to maintain the same interest coverage ratio as if there had been no disallowance of income taxes, whereas the purpose of the adjustment to the equity ratios of the municipally owned utilities in this Decision is to

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[120] Calgary/CAPP Argument, page 59-60

[121] ENMAX Argument, page 36

appropriately account for their higher volatility of earnings. The Board considers these two situations to be fundamentally different.

The Board notes that no party addressed the appropriate adjustment to AltaLink's equity ratio to reflect the partial disallowance of income tax. Assuming that the Board's disallowance of 25% of the requested income taxes is continued, the Board considers that it would continue to be appropriate to adjust AltaLink's equity ratio to maintain the same interest coverage as if there had been no disallowance of income taxes.

Adding the 2% adjustment to the 33% equity ratio determined above for a fully taxable TFO, the Board concludes that an appropriate common equity ratio for AltaLink is 35.0%.

If AltaLink were to have a full income tax allowance included in its approved revenue requirement, the Board considers that the appropriate common equity ratio for AltaLink would then be 33.0%.

5.2.4 NGTL

For the same reasons that were provided above, the Board concludes that an appropriate common equity ratio for NGTL, a gas transmission company, is 35.0%.

5.2.5 ATCO Pipelines

The Board notes that no party took the position that ATCO Pipelines has the same or lower business risk as NGTL, the other gas transmission Applicant. From Table 8, the Board notes that Calgary/CAPP considered ATCO Pipelines to be the highest risk investor owned utility, and that CG considered ATCO Pipelines to be tied with AltaGas as the highest risk utility.

Accordingly, in this section, the Board will assess the appropriate equity ratio for ATCO Pipelines and its differences from the typical gas transmission company. In this regard, the Board will draw on its previous analysis and discussion earlier in this section. Further, the Board will address the additional information applicable to ATCO Pipelines.

The Board notes the general consensus that ATCO Pipelines has higher competition risk than NGTL. Several parties suggested that resolution of outstanding gas pipeline competition issues could result in a reduction to the competition risk faced by ATCO Pipelines. The Board notes that at least some of the competition risk faced by ATCO Pipelines may have resulted from the growth of the system to connect customers either already served by NGTL or in direct competition with NGTL for those loads. The Board also notes that ATCO's largest customer is ATCO Gas, which, in the Board's view, has little credit risk. In any event, the Board considers that it should establish capital structures for 2004 based on the business risks that exist at the time of this Proceeding. The Board does not consider that it should speculate on the possible resolution of outstanding pipeline competition issues.

The Board notes that in NGTL's last Phase I proceeding,[122] the Board indicated that there would be a proceeding to address outstanding gas pipeline competition issues (the Competitive Pipeline Module). The Board considers that the Competitive Pipeline Module is the appropriate forum to

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[122] Application 1315423, Transcript Volume 1, pages 44-49

deal with the inter-pipeline competition matters that may impact the business risks presently confronting ATCO Pipelines.

The Board directs ATCO Pipelines, at the time of its first GRA following the Board's decision in the Competitive Pipeline Module, to apply either:

a) For a change to its deemed equity ratio, to reflect the change in business risk arising from any directions contained within such a decision; or

b) For maintenance of its then existing capital structure on the basis that no change to business risk resulted from the decision in the Competitive Pipeline Module.

The Board notes that CG recommended that the equity ratio of ATCO Pipelines be set at 40%, which was 8% higher than its recommendation for NGTL, while Calgary/CAPP's recommendation for the equity ratio of ATCO Pipelines at 38% was 5% higher than its recommended equity ratio for NGTL.

The Board notes that if the interveners' differentials were applied to the Board's 35% determination for NGTL, the result would be a range of 40% to 43% for ATCO Pipelines.

The Board agrees with all parties that ATCO Pipelines has higher business risk than NGTL.

The Board notes that the last Board decision for ATCO Pipelines, Decision 2003-100, set the 2003 common equity ratio for both ATCO Pipelines North and ATCO Pipelines South at 43.5%.

Regarding gas transmission companies with higher risk than NGTL, the Board notes Dr. Evan's evidence[123] that Pacific Northern Gas (PNG) had an awarded equity ratio of 42.9% and an adjusted actual equity ratio of 44.2%, with a credit rating of BBB (low). The Board also notes Dr. Booth's view[124] that PNG is a highly risky utility and Dr. Robert's view[125] that PNG is riskier than the other utilities.

The Board also notes that ATCO Pipelines has preferred shares in its capital structure. Although the preferred shares provide additional support to the capital structure, in this analysis, the Board has evaluated the appropriate common equity ratio as if the company had no support from its preferred shares.

Considering all of the above, the Board concludes that an appropriate common equity ratio for ATCO Pipelines is 43.0%.

The Board will further address the issue of ATCO's preferred shares below.

5.3 Electric and Gas Distribution

The Board will now consider the appropriate capital structures for the electric and gas distribution Applicants in light of the 5 topic areas set out in section 5.1 as shown below:

1. The business risk of each utility sector and Applicant;

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[123] Exhibit 021-24

[124] Exhibit 016-11(a), Evidence of L. D. Booth, page 54

[125] Transcript, Volume 34, page 5602

2. The Board's last-approved equity ratio for each Applicant (where applicable);
3. Comparable awards by regulators in other jurisdictions;
4. Interest coverage ratio analysis; and
5. Bond rating analysis.

Business Risk

The Board notes the consensus that electric distribution companies are subject to more business risk than electric transmission companies, principally due to their recovery of a significant amount of fixed costs in variable charges and their greater exposure to credit risks.

ATCO proposed that the difference in the equity ratio between its electric distribution companies and its electric TFO should be 12.0-17.0%. The Board observes that 5%-10% of this difference in the equity ratio was due to ATCO's perception of a higher regulatory risk following the passage of the *RDS Amendment Regulation.*[126]

The Board is not persuaded that the *RDS Amendment Regulation* has materially increased the risk to an electric distribution company that has appointed a third-party as RRT provider. The Board notes that the requirement for an electric distribution company to provide a hedged rate is contingent on the default of its RRT provider. The Board notes that it did not receive evidence regarding what contractual protections and security, if any, are available to ATCO in the event of a default by its appointed RRT provider. Also, it is possible that a default would be foreseeable over some period of time prior to it occurring, which may permit time to implement contingency plans to minimize associated impacts. Further, in the event of such a default, an application could be made to the Board to recover, from customers, prudent costs incurred by the electric distribution company in resuming the provision of the RRT. The Board would then consider the merits of such an application, considering factors such as the contractual circumstances and remedies available to the electric distribution company, the circumstances of the RRT appointment, and the potential harm to customers. The Board also notes that no other electric distribution company filed evidence asserting a similar increase in risk.

ATCO also argued that its electric distribution company had higher risk than its electric TFO as a result of potential franchise loss. However, in light of the lack of recent actual occurrences of municipalities closing a transaction pursuant to an option to acquire utilities assets, the Board does not consider, at this time, that the risk of franchise loss or of a municipality acquiring utility assets has increased over what it has been historically. Should there be a material change in the business risk arising from risk of franchise loss an affected utility could apply to the Board at that time to seek appropriate relief.

As shown in Table 8, the Companies, CG and Calgary/CAPP all recommended equity ratios for fully taxable electric distribution companies that were 5% higher than their recommended equity ratios for fully taxable electric transmission companies. The Board understands that this does not necessarily mean that the recommended differential would always be 5%.

ATCO considered the business risk of ATCO Gas to be lower than the business risk of its electric distribution company due to ATCO's perception of a higher regulatory risk for its

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[126] Ministerial Order 73/2003, November 4, 2003

electric distribution company. As discussed above, the Board does not agree with ATCO's perception of the magnitude of the regulatory risk for its electric distribution company.

The Board notes that Calgary/CAPP and CG considered that ATCO Gas has the same or slightly higher business risk than a fully taxable electric distribution company, due to higher volatility of revenue resulting from a different rate design and higher sensitivity to fluctuations in weather conditions.

The Board agrees that a gas distribution company has slightly more risk than a taxable electric distribution company due to higher revenue volatility. The Board does not agree with ATCO that the higher revenue volatility of ATCO Gas is more than offset by higher regulatory risk for electric distribution companies.

The Board notes from Table 8 that parties making recommendations, other than ATCO Gas, suggested that the difference between the equity ratio for ATCO Gas and the equity ratio for a fully-taxable electric distribution company should be in the range of 0-2%.

The Board concludes that electric distribution companies have higher business risks than electric transmission companies, and that gas distribution companies have slightly higher business risk than electric distribution companies.

The Board considers that business risk, in isolation, would indicate that gas distribution companies should have a common equity ratio that is 0-2 % higher than the equity ratio for fully taxable electric distribution companies.

Comparison to Previous Board Awards

The Board notes from Table 8 that the most recent equity ratio approved by the Board for a taxable electric distribution company was 35%, and the most recent equity ratio approved by the Board for fully-taxable electric transmission companies was 32%, a difference of 3%. Earlier in this Decision, the Board determined an equity ratio of 33% for taxable electric transmission companies. The Board considers that this factor, in isolation, would indicate an equity ratio of 36% for the taxable electric distribution companies. Since the Board considers that ATCO Gas has slightly higher business risk than the electric distribution companies, the Board considers that this factor, in isolation, this would indicate an equity ratio of more than 36% for ATCO Gas.

The Board notes from Table 8 that the last equity ratio approved for ATCO Gas was 37%, established in Decision 2003-072. The Board considers that the business risks of ATCO Gas have not changed materially from those assessed by the Board in this prior decision, which, in isolation, would indicate an equity ratio for ATCO Gas of 37%.

Comparable Awards by Regulators in Other Jurisdictions

The Board notes its earlier caveats on relying on comparable awards by other regulators in a previous section of this Decision.

The Board notes that the gas distribution companies in Ontario, Enbridge Gas and Union Gas have been awarded a common equity ratio of 35 to 37% and a total equity ratio of 38 to 40%, treating preferred shares as 80% equity.[127]

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[127] Exhibit 021-24

The Board considers that this information, in isolation, would indicate that the equity ratio for ATCO Gas could be maintained at its current level of 37%.

The Board does not consider that there are any other electric distribution companies in Canada that are comparable to the electric distribution companies in the restructured electric industry in Alberta.

Interest Coverage Ratio Analysis

The Board notes that Enbridge Gas has been awarded an S&P rating of "2".[128] The Board notes Ms. McShane's estimate that ATCO Gas would warrant an S&P risk profile of between "2" and "3". The Board notes that Ms. McShane estimates an S&P risk ranking of "3" for ATCO Electric. However, the Board earlier noted its view that ATCO had over-stated the business risk level of ATCO Electric. In the Board's view, an appropriate S&P risk score for both distribution utilities is between "2" and "2.5".

The S&P guidelines indicate that for a utility with a risk ranking of "2", a pretax interest coverage ratio in the range of 2.3 to 2.9 times is indicated for an "A" debt rating.

Similarly, the S&P guidelines indicate, through pro-rating the guidelines for a "2" and for a "3", that for a utility with a risk ranking of "2.5", a pretax interest coverage ratio in the range of 2.55 to 3.15 times is indicated for an "A" debt rating.

The Board refers the reader to the Interest Coverage Ratio Analysis section provided earlier in the Electric and Gas Transmission section, including the DBRS guidelines indicated there, as additional factors to consider for determining the appropriate common equity ratio for either an electric or a gas distribution company.

Based on this evidence, the Board concludes that an acceptable pretax interest coverage ratio for a taxable electric distribution company distribution company is at or above 2.2 times.

The Board considers that this factor, in isolation, indicates an equity ratio for taxable electric distribution companies and for gas distribution companies higher than the currently approved 35% for ATCO Electric Distribution.

The Board considers gas distribution companies to have slightly more risk than electric distribution companies and, therefore, the Board considers that this factor, in isolation, indicates that gas distribution companies should have slightly more equity than electric distribution companies.

Bond Rating Analysis

The Board notes that Aquila is the only electric or gas distribution company regulated by the Board with its own bond rating. From Table 10, the Board notes that Aquila has a DBRS rating of A (low) based on an equity ratio of 40 to 45.5%. However, the Board notes that Aquila has a

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[128] Exhibit 005-11-1, Capital Structures for the ATCO Utilities, Kathleen McShane, page 11

substantial amount of goodwill[129] on its books, amounting to approximately 29% of its assets at the time of the DBRS report, which would require equity support compared to a distribution company without goodwill. Therefore, based on this factor in isolation, the Board concludes that the target equity ratio for a taxable electric distribution company is somewhat below 40%.

The Board considers the most comparable other Canadian gas and electric distribution companies, available in Dr. Evan's evidence, to be Union Gas and Enbridge Gas.

The Board notes that Union Gas Ltd. has an adjusted actual equity ratio of 35% and credit ratings of A and A-.[130] The Board notes that Enbridge Gas has an adjusted actual equity ratio of 51% and credit ratings of A and BBB+.[131] The Board notes that the date of the adjusted actual equity ratio date is not necessarily the same as the dates of the two credit reports. The Board considers this broad range of adjusted actual equity ratios for Ontario gas distribution utilities and its impact on bond ratings to be of little assistance in this Proceeding.

Conclusion

At the beginning of this section, the Board indicated that it would consider a variety of factors for its determination of the appropriate level of equity in the capital structure of electric and gas distribution companies.

As discussed in the preceding sections, in the Board's view, setting an appropriate equity ratio is a subjective exercise that involves the assessment of several factors and the observation of past experience. The assessment of the level of business risk of the utilities is also a subjective concept. Consequently, the Board considers that there is no single accepted mathematical way to make a determination of equity ratio based on a given level of business risk.

The following table summarizes the indicated equity ratios that arise from various factors as discussed in the earlier sections:

Table 12. Indicated Common Equity Ratios for Distribution Companies by Factor

Factor	Indicated Electric Distribution	Indicated Gas Distribution
Business Risk	Lowest for Distribution	Electric DISCO + 0-2%
Previous Board Awards	~36%	~37%
Awards in Other Jurisdictions	N/A	~37%
Interest Coverage Ratio Analysis	>35%	>35%, >DISCOs
Bond Rating Analysis	<40%	N/A

After considering all of the above factors and after applying its judgment, the Board concludes that an appropriate common equity ratio for a fully taxable electric distribution company with no preferred shares is 37.0%, and that an appropriate common equity ratio for a gas distribution company is 38.0%.

The Board will now consider each electric and gas distribution Applicant, individually.

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[129] Exhibit 004-12, July 31, 2002 DBRS Report on Aquila, page 5 indicating 54.5% net debt at March 31, 2002 (implies 45.5% equity), and indicating 40.0% deemed equity at December 31, 2001; and Decision 2004-035, page 18

[130] Exhibit 021-24

[131] Ibid.

5.3.1 FortisAlberta/Aquila

The Board considers that FortisAlberta (formerly Aquila) does not have any material differences in business risk from the typical electric distribution company.

The Board notes that Aquila is a fully taxable electric distribution company with no preferred shares.

Therefore, for the same reasons that were provided above, the Board concludes that an appropriate common equity ratio for FortisAlberta is 37.0%.

5.3.2 ATCO Electric Distribution

The Board considers that ATCO Electric Distribution does not have any material differences in business risk from the typical electric distribution company.

The Board also notes that ATCO Electric Distribution has preferred shares in its capital structure. Although the preferred shares provide additional support to the capital structure, in this analysis, the Board has evaluated the appropriate common equity ratio as if the company had no support from its preferred shares.

The Board concludes that an appropriate common equity ratio for ATCO Electric Distribution is 37.0%.

The Board will further address the issue of ATCO's preferred shares below.

5.3.3 ENMAX Distribution

The Board considers that ENMAX Distribution does not have any material differences in business risk from the typical electric distribution company.

The Board notes ENMAX's argument that it has additional risks due to its municipal ownership, including a fixed dividend requirement, lack of equity access, and the change in regulator, and that as a result it required a capital structure with 50% common equity.

The Board does not agree with ENMAX that its fixed dividend or lack of access to public equity markets raises its risks in the circumstances. In the Board's view, having established a fair return, the Board need not concern itself with the particular internal policies to which a utility may be subject regarding distributions of dividends or acquisition of equity. The Board also considers that the change in regulator for ENMAX does not result in ENMAX having higher risks, all else being equal, than other electric distribution companies regulated by the Board.

With respect to the ENMAX DISCO, which just came under Board jurisdiction in 2004, the capital structure determined in this Proceeding is based on the assumption that the deferral accounts that the Board will ultimately approve for this Applicant will not be materially different than those in existence at the time of this Proceeding for FortisAlberta/Aquila and ATCO Electric Distribution.

For the same reasons that were provided with respect to EPCOR Transmission above, the Board concludes that the equity ratio for a non-taxable electric distribution company should be 2.0% higher than the equity ratio for a fully taxable electric distribution company.

Therefore, the Board concludes that an appropriate common equity ratio for ENMAX Distribution is 39.0%.

5.3.4 EPCOR Distribution

The Board considers that EPCOR Distribution does not have any material differences in business risk from the typical electric distribution company.

With respect to the EPCOR Distribution, which came under Board jurisdiction in 2004, the capital structure determined in this Proceeding is based on the assumption that the deferral accounts that the Board will ultimately approve for this Applicant will not be materially different than those in existence at the time of this Proceeding for FortisAlberta/Aquila and ATCO Electric distribution companies.

For the same reasons that were provided with respect to ENMAX Distribution above, the Board concludes that an appropriate common equity ratio for EPCOR Distribution is 39.0%.

5.3.5 ATCO Gas

The Board considers that ATCO Gas does not have any material differences in business risk from the typical gas distribution company.

The Board notes that ATCO Gas also has preferred shares in its capital structure. Although the preferred shares provide additional support to the capital structure, in this analysis, the Board has evaluated the appropriate common equity ratio as if the company had no support from its preferred shares.

As determined above, the Board concludes that an appropriate common equity ratio for ATCO Gas is 38.0%.

The Board will further address the issue of ATCO's preferred shares below.

5.3.6 AltaGas

The Board considers that AltaGas has greater business risk than the typical gas distribution company.

AltaGas and ATCO Gas considered the business risks of AltaGas to be higher than the business risks of ATCO Gas, due to AltaGas' relatively small size, rural service area, geographically dispersed customers and high level of customer contributions.

Calgary/CAPP was the only party who took the position that AltaGas did not have higher business risks than ATCO Gas. Calgary/CAPP considered the main risk to AltaGas to be commodity cost risk, for which AltaGas has a deferral account. As a result, Calgary/CAPP recommended the same equity ratio for AltaGas as for ATCO Gas.

The Board notes that AltaGas' parent has a credit rating of BBB (low) and has been unable to raise debt with a term longer than five years. AltaGas had the view that, due to its size, it was very unlikely that it would be able to access debt on more favourable terms than its parent.[132]

The Board notes that AltaGas' parent is involved in a significant level of non-regulated activities. The Board is unable to establish the effect that those activities have on the parent's rating. The Board is not persuaded that that AltaGas would not have a higher rating than its parent and that it would not be able to access debt on more favourable terms than its parent. Nonetheless, the Board is persuaded that the business risks of AltaGas are greater than the business risks of a typical gas distribution company because of the nature of its service territory, not necessarily because of its smaller size.

The Board notes that CG's recommended equity ratio for AltaGas was 3% higher than its recommended equity ratio for ATCO Gas, whereas AltaGas and ATCO considered that the equity ratio for AltaGas should be 5% higher. The Board considers that this factor, in isolation indicates that the equity ratio for AltaGas should be 41-43%.

The Board notes that the previous Board approved equity ratio for AltaGas was 41%.

Considering all of the above, the Board concludes that an appropriate common equity ratio for AltaGas is a continuation of its currently approved 41%.

5.4 Utility-Specific Adjustments to ROE

Some parties in this Proceeding indicated that when a common ROE approach is used, it might be necessary to consider a utility-specific adjustment to the common ROE to adequately reflect the investment risks of individual utilities.

In particular, the Board notes that ATCO Pipelines indicated that an adjustment to its ROE was required to adequately compensate its investors for the risks confronting the company, because adjustments to capital structure would not be sufficient.

As noted earlier in this Decision, the Board considers that unique utility-specific adjustments to the generic ROE should only be made in exceptional circumstances where adjusting capital structure alone is not sufficient to reflect the investment risk for a particular Applicant.

The Board notes that the equity ratio approved for ATCO Pipelines in this Decision is marginally lower than the last Board-approved equity ratio for ATCO Pipelines. The Board considers that the capital structure for ATCO Pipelines in this Decision adequately reflects the investment risk for ATCO Pipelines.

The Board concludes that there is no need for utility-specific adjustments to the common ROE for any of the Applicants.

5.5 2004 Deemed Common Equity Ratios

Based on the Board's findings above, the Board approves the following deemed common equity ratios for 2004:

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[132] AltaGas Argument, page 32

Table 13. **Board Approved Equity Ratios**

	Last Board-Approved Common Equity Ratios (%)	2004 Board Approved Common Equity Ratios (%)	Change in Approved Common Equity Ratio (%)
ATCO TFO	32.0	33.0	1.0
AltaLink	34.0[133]	35.0	1.0
EPCOR TFO	35.0	35.0	0.0
NGTL	32.0	35.0	3.0
ATCO Electric DISCO	35.0	37.0	2.0
FortisAlberta (Aquila)	N/A [134]	37.0	N/A
ATCO Gas	37.0	38.0	1.0
ENMAX DISCO	N/A [135]	39.0	N/A
EPCOR DISCO	N/A [125]	39.0	N/A
AltaGas	41.0	41.0	0.0
ATCO Pipelines	43.5	43.0	(0.5)

5.6 ATCO Utilities Preferred Shares

In earlier sections, the Board noted that the 2004 approved common equity ratios in this Decision for the ATCO utilities were not adjusted to reflect any impact of ATCO's use of preferred shares. The Board notes that there was essentially no evidence presented regarding the impact of preferred shares on the required common equity ratios.

The Board has recognized in previous decisions that during the period of time when income tax rebates were in place, it was prudent to utilize preferred share financing in place of debt.

However, the Board considers that there may be merit in further consideration of the appropriateness of the continuing use of preferred shares as a form of financing, to understand the redemption options and to fully explore the related implications and options.

The Board directs ATCO to address the appropriateness of the continuing use of preferred shares as a form of financing, in the next Phase 1 GRA/GTA for ATCO Gas, ATCO Pipelines or ATCO Electric, whichever comes first.

5.7 Process to Adjust Capital Structure

The Board notes that all parties, except for CG, considered that it would be appropriate to address any future changes in capital structure in utility-specific GRA/GTAs. CG proposed a scheduled review of the capital structures of all Applicants.

The Board agrees with the general consensus that it would be more appropriate to address any future changes in capital structure in utility-specific GRA/GTAs. The Board also agrees with the general consensus that such changes should only be pursued if parties perceive that there has

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[133] In Decision 2003-061, the Board approved an equity ratio for AltaLink of 32%, plus an additional 2% to offset the impact on the interest coverage ratio of a partial allowance of income taxes in the revenue requirement.

[134] The Board did not specifically approve this ratio; it was part of a negotiated settlement approved in Decision 2003-019, which included a deemed 40% equity ratio as one of many settled parameters of the revenue requirement.

[135] Both EPCOR and ENMAX Distribution were subject to Board jurisdiction effective January 1, 2004.

TAB 6

BRITISH COLUMBIA
UTILITIES COMMISSION

IN THE MATTER OF

TERASEN GAS INC. AND TERASEN GAS (VANCOUVER ISLAND) INC. APPLICATION TO DETERMINE THE APPROPRIATE RETURN ON EQUITY AND CAPITAL STRUCTURE AND TO REVIEW AND REVISE THE AUTOMATIC ADJUSTMENT MECHANISM

DECISION

MARCH 2, 2006

Before:

R.H. Hobbs, Panel Chair
R.J. Milbourne, Commissioner
A.J. Pullman, Commissioner

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1.0 EXECUTIVE SUMMARY

On June 30, 2005, Terasen Gas Inc. ("TGI") and Terasen Gas (Vancouver Island) Inc. ("TGVI") applied to the Commission to determine the appropriate return on equity and capital structure and to review and revise the automatic adjustment mechanism. TGI's return on equity and capital structure were established following a generic hearing by the Commission in 1994, at 350 basis points over the forecast long Canada bond yield and an equity component of 33 percent. The automatic adjustment mechanism was amended in 1999, with the result that when long Canada bond yields are forecast to be below 6 percent, the ROE rises and falls in step with the forecast long Canada bond yield. TGI has the lowest return on equity and smallest equity component of capital structure of any gas distribution company in Canada.

Up to 2002 TGVI's return on equity and capital structure were established by Special Direction issued by the Lieutenant Governor in Council to the Commission. Thereafter, under the Commission's negotiated settlement process, they were determined to be a 50 basis point premium over the return on equity of the benchmark low-risk utility (which the Commission determined to be TGI) and an equity component of 35 percent.

The Applicants seek the following returns on equity (based on the November 2006 consensus long Canada bond yield forecast of 4.79 percent) and equity component:

TGI	10.16%	38%
TGVI	10.91%	40%

The Commission Panel determines that both the comparable earnings standard and the capital attraction standard are equally relevant in establishing a fair return.

Accordingly, the Commission Panel gives weight to both the Equity Risk Premium and the Discounted Cash Flow approaches to establishing a fair rate of return. It is unable to give any weight to the Comparable Earnings of low-risk Canadian industrials in this proceeding, although it believes that this approach may play a role in future hearings.

The Commission Panel concludes that the appropriate return on equity for a benchmark low-risk utility is 3.90 percent over the forecast long Canada bond yield. The Commission Panel determines that TGI will continue to be the benchmark low-risk utility. The Commission Panel also concludes that a revision to the automatic adjustment mechanism is appropriate, such that the return on equity will be adjusted by 75 percent of the change in forecast long Canada bond yields, effective January 1, 2006. Accordingly, the return on equity for

TGI for 2006 will be 8.80 percent and its equity component will be 35 percent. For TGVI the Commission Panel determines that a 70 basis point premium over the benchmark low-risk utility is appropriate for a return for 2006 of 9.50 percent, and an equity component of 40 percent.

5.0 CAPITAL STRUCTURE

This section considers the appropriate capital structures for TGI and TGVI.

Dr. Booth believes the Commission should adjust for changes in business risk through the establishment of deferral accounts, as far as is practicable, then to alter the amount of debt financing; and then to alter the allowed ROE (Exhibit C2-6, p. 24). A review of deferral accounts is outside the scope of this proceeding. Therefore, determinations in this decision with respect to capital structure and returns on equity assume the deferral accounts are not changed. Further, the Commission Panel has used both capital structure and rates of return for establishing the appropriate financial profile for the Applicants. In this decision, the capital structure of TGI will be determined so as to equate TGI to the benchmark low-risk utility. In the case of TGVI, the reasonableness of the proposed capital structure and equity premium off of the return on equity for the benchmark low risk utility will be considered.

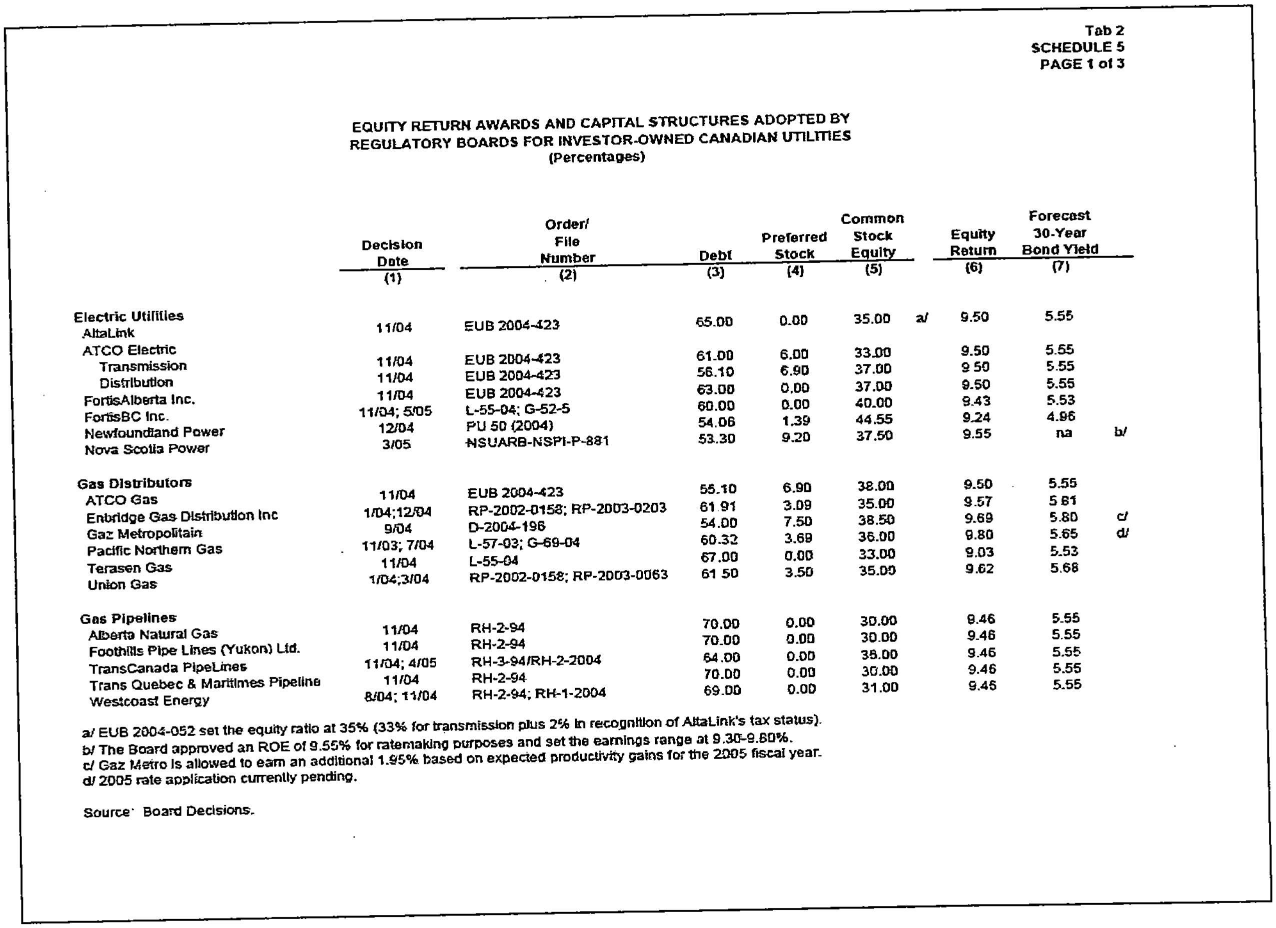
The capital structures of other B.C. utilities are outside the scope of this proceeding, although the approved capital structures of other B.C. utilities are considered relevant to the determination of an appropriate capital structure for TGI and TGVI.

5.1 TGI

The Applicants apply for a 38 percent common equity ratio for TGI.

5.1.1 Capital Structures of Other Canadian Gas Distribution Utilities

The table below provides the capital structures of other Canadian Gas Distribution Utilities:



Tab 2
SCHEDULE 5
PAGE 1 of 3

EQUITY RETURN AWARDS AND CAPITAL STRUCTURES ADOPTED BY REGULATORY BOARDS FOR INVESTOR-OWNED CANADIAN UTILITIES
(Percentages)

	Decision Date (1)	Order/ File Number (2)	Debt (3)	Preferred Stock (4)	Common Stock Equity (5)	Equity Return (6)	Forecast 30-Year Bond Yield (7)
Electric Utilities							
AltaLink	11/04	EUB 2004-423	65.00	0.00	35.00 a/	9.50	5.55
ATCO Electric							
Transmission	11/04	EUB 2004-423	61.00	6.00	33.00	9.50	5.55
Distribution	11/04	EUB 2004-423	56.10	6.90	37.00	9 50	5.55
FortisAlberta Inc.	11/04	EUB 2004-423	63.00	0.00	37.00	9.50	5.55
FortisBC Inc.	11/04; 5/05	L-55-04; G-52-5	60.00	0.00	40.00	9.43	5.53
Newfoundland Power	12/04	PU 50 (2004)	54.06	1.39	44.55	9.24	4.96
Nova Scotia Power	3/05	NSUARB-NSPI-P-881	53.30	9.20	37.50	9.55	na b/
Gas Distributors							
ATCO Gas	11/04	EUB 2004-423	55.10	6.90	38.00	9.50	5.55
Enbridge Gas Distribution Inc	1/04;12/04	RP-2002-0158; RP-2003-0203	61 91	3.09	35.00	9.57	5 81
Gaz Metropolitain	9/04	D-2004-196	54.00	7.50	38.50	9.69	5.80 c/
Pacific Northern Gas	11/03; 7/04	L-57-03; G-69-04	60.32	3.69	36.00	9.80	5.65 d/
Terasen Gas	11/04	L-55-04	67.00	0.00	33.00	9.03	5.53
Union Gas	1/04;3/04	RP-2002-0158; RP-2003-0063	61 50	3.50	35.00	9.62	5.68
Gas Pipelines							
Alberta Natural Gas	11/04	RH-2-94	70.00	0.00	30.00	9.46	5.55
Foothills Pipe Lines (Yukon) Ltd.	11/04	RH-2-94	70.00	0.00	30.00	9.46	5.55
TransCanada PipeLines	11/04; 4/05	RH-3-94/RH-2-2004	64.00	0.00	36.00	9.46	5.55
Trans Quebec & Maritimes Pipeline	11/04	RH-2-94	70.00	0.00	30.00	9.46	5.55
Westcoast Energy	8/04; 11/04	RH-2-94; RH-1-2004	69.00	0.00	31.00	9.46	5.55

a/ EUB 2004-052 set the equity ratio at 35% (33% for transmission plus 2% in recognition of AltaLink's tax status).
b/ The Board approved an ROE of 9.55% for ratemaking purposes and set the earnings range at 9.30-9.80%.
c/ Gaz Metro is allowed to earn an additional 1.95% based on expected productivity gains for the 2005 fiscal year.
d/ 2005 rate application currently pending.

Source: Board Decisions.

Source: Exhibit B-1, Tab 2, Schedule 5, p. 1

As indicated in the above table, all the other major gas distribution utilities have preferred shares in their capital structures. Since 1994 the allowed common equity of TGI has been 33 percent. In 1999 preferred shares were redeemed that accounted for 9.4 percent of the capital structure. The preferred shares of ATCO Gas, Enbridge, and Union are perpetual preferred shares. The Commission Panel accepts the evidence of TGI that it does not have a credit rating high enough to enable it to issue perpetual preferred shares (T3: 267). Therefore, the Commission Panel concludes that the preferred shares of ATCO Gas, Enbridge and Union need to be considered when comparing the capital structures of those utilities with TGI.

Ms. McShane and Dr. Booth reach similar conclusions regarding the relative risk of Canadian utilities. Ms. McShane's view is that TGI's business risks are comparable to those of the major Alberta and Ontario distributors, and exceed those of electric transmission companies by a considerable margin (Exhibit B-1, Tab 2, p. 16). Dr. Booth is also of the view that electric transmission companies have a lower risk than TGI, and are judged to be the lowest risk regulated utilities in Canada. The AEUB has found that appropriate capital structure for electric transmission companies with no preferred shares is 33 percent.

McShane is of the view that TransCanada Pipelines and Nova Gas Transmission face no higher business risk than TGI. Dr. Booth is of the view that the gas transmission pipelines are the second lowest risk group. The allowed common equity ratio for TransCanada Pipelines, Mainline and Nova Gas Transmission are 36 percent and 35 percent respectively.

Dr. Booth then judged the local distribution companies, including both gas and electric as the next riskiest. Ms. McShane is of the view that TGI's business risks are comparable to those of the major Alberta and Ontario gas distributors. The allowed common equity ratios for the Ontario major gas distributors are in the range of 35 percent and the allowed common equity ratios for the Alberta gas distributors are higher at 38 percent.

In testimony, Dr. Booth indicated that TGI is riskier than ATCO Gas and Enbridge, roughly on par with Union, while being less risky than Gaz Metro (T5: 619-620). Dr. Booth views PNG and Gaz Metro as the riskiest regulated utilities in Canada (Exhibit C2-6, p. 36).

Although Dr. Booth recommends 35 percent for a typical local gas distribution company, he recommends 33 percent for TGI because of more comprehensive deferral accounts. The Commission Panel accepts that the TGI's earnings are less volatile than the earnings of Enbridge and Union, and such reduced volatility can be attributed, in part, to weather normalization. The Commission Panel also notes Dr. Booth's testimony that "I think they (sc Enbridge and Union) are probably happier not having weather normalization. Otherwise they would have proposed it" (T5: 639). The Applicant submits that the existence of the RSAM account is not a factor that should play a role in the determination of its allowed return on equity or its capital structure. Dr. Booth confirmed in his opening statement that weather risk should not affect the return on equity (TGI/TGVI Submissions, p. 14, para. 46 and 47).

5.1.2 Coverage Ratios and Credit Ratings

The pre-tax interest coverage ratios for the major gas distribution companies in Canada are set out below:

PRE-TAX INTEREST COVERAGE RATIOS
FOR MAJOR CANADIAN UTILITIES

Company	1995	1996	1997	1998	1999	2000	2001	2002	2003
Enbridge Gas Distribution	2.0	2.6	2.6	2.1	2.2	2.2	2.8	2.7	2.7
Gaz Metro	2.6	2.6	2.7	2.7	2.4	2.7	2.5	2.9	2.9
Pacific Northern Gas	2.1	2.7	2.6	2.3	2.3	2.3	2.3	2.5	2.3
Terasen Gas	1.8	2.0	2.3	2.3	2.3	1.9	1.8	2.0	2.0
Union Gas	2.2	2.3	2.4	2.0	1.8	2.0	1.9	2.1	2.1

Source DBRS (Exhibit B-1, Tab 2, Schedule 2)

TGI's interest coverage ratio for 2004 was 1.99 (Exhibit B-28)

TGI's Medium Term Note ratings for the years 1994, 1999 and 2004 are set out below:

Rating Agencies	**1994**	**1999**	**2004**
DBRS	A	A	A
Moody's	-	-	A2
CBRS/S&Ps	B++	A (low)	BBB (unsolicited)

Source: Exhibit B-3, Vol. 1, Appendix 2.1

On June 26, 2003, Standard & Poors downgraded TGI's rating from BBB+ to BBB. In the first quarter of 2004 TGI terminated Standard & Poors' engagement to provide credit ratings in order to manage costs. However, S&P elected to continue to publish unsolicited credit ratings on TGI debt. On December 19, 2005, Moody's lowered TGI's senior secured rating from A1 to A2 and TGI's senior unsecured rating from A2 to A3 (Exhibit B-27). Both Moody's and S&P are of the view that the low common equity component in the capital structure of TGI results in a weak financial profile. TGI submits that the December 2005 downgrading demonstrates the need for an increase to the common equity and return on equity for TGI (TGI/TGVI Reply Submissions, p. 27).

In its credit rating report on TGI dated June 22, 2004, DBRS makes the following comments on TGI from a credit analyst's (and thus bondholder's) perspective:

> "The company benefits from a supportive regulatory regime,"
>
> "The regulatory environment within which the company operates provides a relatively high degree of financial stability."
>
> "Key financial ratios are expected to continue to fluctuate within a narrow band in line with changes in working capital requirements, however, this does not pose any credit implications."
>
> "Terasen Gas has historically had the lowest allowed ROEs relative to all other gas distribution utilities in Canada. This has resulted in generally weaker financial ratios relative to its Canadian peers," and
>
> "The use of the taxes payable method of taxation (typical of rate-regulated utilities) has resulted in an unrecorded future income tax liability of $215.8 million as at December 2004. The recovery of this liability in future rates depends on regulation" (Exhibit B-5, Appendix 1.2).

The Commission Panel notes these comments by DBRS. First, the interest coverage ratios are stable and are unlikely to pose any credit implications in the future. Second, the lowest allowed returns, when combined with the lowest equity component relative to all other gas distribution utilities in Canada, have resulted in the lowest interest coverage ratios in Canada.

The Commission Panel accepts that if TGI is downgraded by one of the rating agencies to a non-investment credit that it could limit the number of investors willing to hold TGI debt securities. For that reason, investors may be reluctant to hold debt that is just one notch above BBB-. A credit rating below an S&P BBB- is considered "junk" (T3: 263-265). Therefore, TGI's credit rating would fall to non-investment grade (junk) status if S&P downgrades TGI by only two notches. In the December 19 Announcement, Moody's states:

> "TGI's rating considers the support provided by TGI's regulatory environment which limits TGI's exposure to commodity price and volume risks as well as pension funding costs and insurance costs by operation of numerous deferral mechanisms including Commodity Cost Reconciliation Account (CCRA), Midstream Cost Reconciliation Account (CCRA) and the Revenue Stabilization Adjustment Mechanism (RSAM). However, the rating also recognizes that the deemed equity and allowed ROE permitted by the regulator are among the lowest in Canada which contributes to TGI's weak financial metrics relative to its global peers" (Exhibit B-27).

The Applicants submit that TGI's hedging agreements require that collateral be posted if its rating falls to non-investment grade, which could trigger significant and sudden liquidity requirements. TGI's gas purchase agreements require that collateral be posted if the counterparty has reasonable grounds for insecurity, which could be triggered by a downgrade to non-investment grade (TGI/TGVI Submissions, p. 25, para. 85; T3: 265).

Dr. Booth believes that because bond rating agencies are concerned with accurately predicting the credit quality of a firm's debt, they take a conservative approach because of "asymmetry of risk" and sometimes over react (Exhibit C2-6, pp. 76-77). Moreover, Dr. Booth submits that S&P's decision to impose harsher credit standards has had no impact on spreads or presumably marketability of future debt issues, and notes that spreads have almost all declined since end of 2002 (Exhibit C2-6, p. 78). During the Oral Phase of Argument, TGI advised that there has been no determinable change in the market following the Moody's downgrade (T7: 984). The JIESC submits that the ratings are the agency's view of the utility, and that a more important view is the markets view as evidenced by the spreads.

The spreads of TGI with comparators including Enbridge and Union are provided at Exhibit C2-11, Exhibit C2-11 and BCUC IR No. 1, 32.1.1.2. TGI's 30-year bonds trade at spreads that are approximately 15-20 basis points higher than Enbridge and at spreads that are similar to Union's. In Reply Argument, TGI submits that TGI bonds trade at approximately 30 basis points higher than Enbridge; however, the trade spreads indicated on BCUC IR No. 1, 32.1.1.2 are 20 basis points and the estimated spreads for a new 30 year issue are approximately 30 basis points. TGI then submits that the "30 basis point spread" reflects a "particularly accommodating point in the interest cycle for TGI bonds" (TGI/TGVI Reply Submissions, p. 20).

Dr. Booth's view is that the S&P and the Moody's ratings for Terasen are out of line with what the market feels is the correct rating. During the Oral Phase of Argument, the JIESC also notes that both the Moody's and DBRS ratings are "A" ratings (T7: 978).

The Commission Panel also notes the submissions of TGI that from the perspective of independent parties, who can see there has been a change, the downgrades suggest the business risks and the financial risks of TGI have increased (T7: 980).

5.1.3 Access to Capital Markets and Financing Flexibility

The JIESC observes that TGI was able to raise 30 year debt in 2005 on reasonable terms. The Applicant's Treasurer Mr. Bryson states:

> "I think the point that I want to leave on this is that obviously one of the key standards that a fair return on equity and capital structure has to meet is the ability to raise financing even in adverse conditions. And I think that was acknowledged by this Commission in the 1999 ROE decision. And what I'd like to submit is that the ability to issue 30-year bonds once every five or ten years does not provide evidence that that test is being met" (T2: 154).

Mr. Bryson states that in 2005 at least seven BBB rated companies were able to issue 30 year debt (T2: 127).

The Commission Panel accepts the need for a utility to be able to access capital markets under most circumstances at reasonable rates.

Commission Determinations

The Commission Panel concludes that the appropriate capital structure range for consideration of TGI is in the range of 35 percent to 38 percent and that given the effect of deferral accounts in reducing the risk of TGI, the appropriate equity component for TGI is 35 percent. Given the preferred shares in the capital structure of all other Canadian gas distribution utilities, the equity component of TGI will remain the lowest in Canada for gas distribution utilities.

While the Commission Panel accepts the submissions of the JIESC that since utilities have the lowest business risk of just about any sector they should have the highest debt ratios, it nevertheless concludes that an increase to the capital structure of TGI is supported by post-1994 changes to the capital structure of TGI and by comparisons to the approved capital structures of comparable risk utilities. Credit rating downgrades by S&P and Moody's are relevant and also support a need for a change to the capital structure.

The Commission Panel requires TGI to file within 30 days of this decision a document setting out how and when it will implement this change to its capital structure in compliance with the ring-fencing conditions approved by the Commission on page 49 of the KMI Decision.

5.2 TGVI

The Applicants apply for a 40 percent common equity ratio for TGVI.

TGVI is also in an increasingly competitive environment. Ms. McShane says that TGVI faces higher risk than any of the major mature gas distribution utilities, and is more comparable to the smaller mature utilities and the greenfield gas distributors in the Maritimes (Exhibit B-1, p. 20). In particular, Ms. McShane views TGVI to be somewhat less risky than either of Enbridge Gas New Bruswick or Heritage Gas and to be in the same business risk class as Gazifiere Inc. and Natural Resource Gas. Ms. McShane also views TGVI to have higher business risk than FortisBC (Exhibit B-3, Vol. 2, IR 1.45.3). Ms. McShane provides the allowed common equity ratios of these utilities, which have a range from 40 percent to 50 percent and recommends a common equity range for TGVI of 45-50 percent.

The business circumstances of TGVI have changed since Ms. McShane's evidence was filed. TGVI has not sought a thicker common equity ratio or a higher return on equity as a result of the new circumstances, but submits that the circumstances have changed the business risks and provide further evidence of the reasonableness of the capital structure and return on equity that is being sought by TGVI.

The Applicants note that TGVI has the same allowed common equity as Enbridge, has no preferred shares, and is allowed approximately the same level of equity as Enbridge. Further, that the risk profiles of TGVI and Enbridge are not remotely similar (TGI/TGVI Submissions, p. 32).

Dr. Booth did not file evidence related to TGVI. The JIESC submits that there is no justification for changing the capital structure of TGVI at this time and that it does not make sense to do so.

Commission Determinations

The Commission Panel concludes that the appropriate common equity component in the capital structure of TGVI is 40 percent.

The Commission Panel requires TGVI to file within 30 days of this decision a document setting out how and when it will implement this change to its capital structure in compliance with the ring-fencing conditions approved by the Commission on page 49 of the KMI Decision.

TAB 7

NATIONAL ENERGY BOARD
OFFICE NATIONAL DE L'ÉNERGIE

Hearing Order GH-1-2004
Ordonnance d'audience GH-1-2004

MACKENZIE GAS PROJECT/PROJET GAZIER MACKENZIE

IMPERIAL OIL RESOURCES VENTURES LIMITED
MACKENZIE VALLEY ABORIGINAL PIPELINE LIMITED PARTNERSHIP
CONOCOPHILLIPS CANADA (NORTH) LIMITED
SHELL CANADA LIMITED
EXXONMOBIL CANADA PROPERTIES
IMPERIAL OIL RESOURCES LIMITED

VOLUME 46

Hearing held at
L'audience tenue à

The Midnight Sun Recreation Complex
194 Gwich'in Road
Inuvik, NWT

December 13, 2006
le 13 décembre 2006

International Reporting Inc.
Ottawa, Ontario
(613) 748-6043

Canada

This publication is the recorded verbatim transcript and, as such, is taped and transcribed in either of the official languages, depending on the languages spoken by the participant at the public hearing.

Cette publication est un compte rendu textuel des délibérations et, en tant que tel, est enregistrée et transcrite dans l'une ou l'autre des deux langues officielles, compte tenu de la langue utilisée par le participant à l'audience publique.

Printed in Canada

Imprimé au Canada

HEARING ORDER/ORDONNANCE D'AUDIENCE
GH-1-2004

IN THE MATTER OF an application for the Mackenzie Valley Pipeline
filed by Imperial Oil Resources Ventures Limited pursuant to
section 52 of the *National Energy Board Act*;

AND IN THE MATTER OF an application for the Mackenzie Gathering System
filed by Imperial Oil Resources Ventures Limited pursuant to paragraph 5.(1)(b)
of the *Canada Oil and Gas Operations Act*;

AND IN THE MATTER OF three Development Plan applications for the three anchor
fields in the Mackenzie Delta area supporting the pipelines, filed by Imperial Oil
Resources Limited, ConocoPhillips Canada (North) Limited and Shell Canada
Limited pursuant to section 5.1 of the *Canada Oil and Gas Operations Act*.

HEARING LOCATION/LIEU DE L'AUDIENCE

Hearing held at Inuvik (Northwest Territories), Wednesday, December 13, 2006

Audience tenue à Inuvik (Territoires du Nord-Ouest) Mercredi, le 13 décembre, 2006

BOARD PANEL/COMITÉ D'AUDIENCE DE L'OFFICE

K. Vollman	Chairman/Président
G. Caron	Member/Membre
D. Hamilton	Member/Membre

APPEARANCES/COMPARUTIONS

Applicants/Demandeurs

Imperial Oil Resources Ventures Limited
- Mr. D. G. Davies
- Mr. T. Hughes

Imperial Oil Resources Limited
- Mr. D.G. Davies

Shell Canada Limited
- Mr. Darrell Gough
- Mr. Shawn Denstedt
- Ms. Mary Henderson
- Mr. Brad Gilmour
- Mr. Ryan Rodier

ConocoPhillips Canada (North) Limited
- Mr. Bob Bleaney
- Mr. B. Houghton

Intervenors/Intervenants

Alternatives North
- Ms. B. Saunders
- Mr. J. Johnson
- Ms. S. Montgomery

Apache Canada Ltd.
- Mr. .A.W. (Sandy) Carpenter

Arctic Youth Alliance
- Mr. F. Isiah

Ayoni Keh Land Corporation
- Mr. L. Douglas Rae

BP Canada Energy Company
- Mr. D.T. McGrath

Canadian Association of Petroleum Producers
- Mr. Nick Schultz

APPEARANCES/COMPARUTIONS

Intervenors/Intervenants (Continued/Suite)

Chevron Canada Resources
- Mr.N. Dustan

Dene Tha' First Nation
- Mr. R.C. Freedman

EnCana Corporation
- Mrs. Rinde K. Powell

Environment Canada
- Ms. Cayley Jane Thomas

Fort Providence Métis Council
- Mr. A.J. Lafferty

Government of Canada - Crown Consultation Unit
- Mr. J.M. Shaw

Indian and Northern Affairs Canada
- Mr. Scott Duke
- Mr. Richard Graw

K'asho Got'ine District Lands Corporation
- Mr. A. Tobac

Mackenzie Explorer Group
- Mr. Jerry Farrell
- Mr. D. Crowther

Mackenzie Valley Aboriginal Pipeline
- Mr. Robert Reid

Mosbacher Operating Ltd.
- Mr. Lewis L. Manning

North Slave Métis Alliance
- Ms. S. Grieve

Government of Northwest Territories
- Mr. Chris W. Sanderson
- Mr. Keith Bergner
- Mr. James Fulford

APPEARANCES/COMPARUTIONS

Intervenors/Intervenants (Continued/Suite)

Paramount Resources Ltd.
- Mr. Alan S. Hollingworth

Sierra Club of Canada
- Mr. Paul Falvo

Talisman Energy
- Mr. Frank C. Basham

TransCanada PipeLine Limited
- Mr. B. Arthur

World Wildlife Fund - Canada
- Mr. Paul Falvo

Government of Yukon
- Mr. James H. Smellie

National Energy Board/Office national de l'énergie

- Mr. Peter Enderwick

ERRATA

Monday, December 11, 2006 - Volume 44:

Paragraph No.	Should read:
P7455/L1: "... they may like the conditions they ..."	"... they may not like the conditions they ..."

TABLE OF CONTENTS/TABLE DES MATIÈRES

(Note: Paragraph numbers go back to 1. as of Volume 36)

LIST OF EXHIBITS/LISTE DE PIÈCES

No.	Description	Paragraph No./No. paragraphe

LIST OF UNDERTAKINGS/LISTE DES ENGAGEMENTS

No.	Description	Paragraph No./No. Paragraphe
U-44	To provide an explanation of what the 18 Bcf means within the limits of the evidence that appears in Volume 6 of the transcript	9263

Dr. Booth?

10274. **DR. BOOTH:** I still don't think it's material.

10275. What you're saying, essentially, is that after this Board approves the pipeline and after all the -- enough shippers sign on, that Imperial decides to proceed with the project, that partway through, the costs of the project will have so exceeded any potential contingency that they decide the economics just aren't there.

10276. So I would like to see a greater discussion by the proponents of the situation which this risk could materialize.

10277. **MR. DAVIES:** In any event --

10278. **DR. BOOTH:** Apart from this comment by Dr. Safir, as I mentioned, when the Board staff asked, the risks that underlie the premium in terms of the pipeline, this wasn't a risk that was mentioned.

10279. **MR. DAVIES:** In any event, Dr. Booth, we can debate, as I say, the materiality of the construction risk, but can we agree that there is some residual construction risk that falls upon the pipeline?

10280. **DR. BOOTH:** We can agree that this -- there is some residual risk, but we can also mention that this wasn't a risk that the company felt material enough to embed in the 221 basis points premium.

10281. It wasn't a risk the company felt was material enough either.

10282. **MR. DAVIES:** Let's turn to the operating phase of the project and here your recommendation is for a provisional 50 basis points above the NEB formula on a 30 percent equity ratio; right?

10283. **DR. BOOTH:** That's correct.

10284. **MR. DAVIES:** And if we go back to your testimony, Exhibit MEG-5(c), and this is page two, Adobe page three.

10285. The last bullet or the last indented bullet, Dr. Booth, you say that your recommendation is generous given that the MVP is to be a full cost-of-service pipeline backed by FST agreements with some of the strongest companies in Canada; right?

10286. **DR. BOOTH:** That's correct.

10287. **MR. DAVIES:** Have you ever made a cost of capital recommendation for a utility in a regulatory proceeding that you haven't considered to be generous?

10288. **DR. BOOTH:** I've turned down requests to provide evidence where I didn't think that I could provide evidence because I felt the pipe -- the utility was risky.

10289. **MR. DAVIES:** Well, that wasn't my question.

10290. My question was: Have you ever made a cost of capital recommendation for a utility in a regulatory proceeding that you haven't considered to be generous?

10291. **DR. BOOTH:** I'd have to defer on that.

10292. I can't remember the -- when I first made recommendations, my recommendations were a lot closer to the actual estimates of the cost of capital.

10293. For example, sir, the first evidence that I filed was a lot stricter than testimony I've filed over the last five or six years. For example, before the Alberta Energies and Utilities Board, I said that NGT should get a 30 percent common equity ratio but I said that since it was now part of the TransCanada group, I would recommend the continuation of the 33 percent common equity ratio.

10294. So that was certainly an example where I made a recommendation that was three percent -- in terms of the common equity ratio -- higher than my individual analysis suggested.

10295. And the same, I think, in the TransCanada hearing, the 2001, I recommended 30 percent common equity ratio and I think -- or the maintenance of a 30 percent common equity ratio even though my individual risk analysis suggested 28 percent.

10296. So if you're saying in all of my testimonies, I would say, over the last five to ten years, I've made recommendations that have been consistently higher than my personal assessments of both the equity cost and the common equity ratio.

10297. **MR. DAVIES:** And often lower than what is considered to be reasonable by the Board?

10298. **DR. BOOTH:** I don't know about reasonable by the Board.

10299. There's a range of reasonableness, but just to -- I mean, just to back up on this, the -- a close reading of my evidence here will indicate that in several places I've been generous in the sense that in terms of coming up with the -- the rate of return for both the integrated and the independence, instead of using my market risk premium estimate of 4.5 percent, I used the Board's six percent. So I would say that was -- would be generous compared to what I've been recommending.

10300. In terms of the debt cost in the construction phase, I used 4.25 percent even though the actual debt costs for a AA-rated three to five year borrower was significantly lower than that.

10301. So in this testimony, I have been generous. I've made recommendations in several areas that are generous towards the company. And I would say, over the last five to ten years, I've tended to do that more than when I was -- when I first provided testimony 20 years ago.

10302. **MR. DAVIES:** Have you ever seen the movie, Scrooge?

--- (Laughter/rires)

10303. **MR. DAVIES:** Dr. Booth --

10304. **DR. BOOTH:** I would like to know the reference, Mr. Davies, to that comment?

10305. **MR. DAVIES:** Dr. Booth, you subscribe to the view, I take it, that a pipeline with what you call "a full cost-of-service toll recovery methodology" has less business risk than a pipeline that collects revenue on a forward test year basis?

10306. **DR. BOOTH:** Yes.

10307. Now, just to qualify that, I always look at the business risk as the underlying supply/demand economics of the pipeline and then I'll look at regulatory protection in terms of how regulation affects that business risk.

10308. And I would say that you can have the same business risk pipeline and then it's the regulation in terms of a full cost-of-service, that lowers the end risk to the shareholders rather than the forward test year.

10309. So I don't regard that as business risk. I regard that as regulatory protection.

10310. **MR. DAVIES:** And in fairness, Dr. Booth, in the RH-2-94 decision, the Board said that the method of regulation had only a marginal impact on the overall risk of the pipeline; right?

10311. **DR. BOOTH:** That is correct.

10312. In fact, I think I referenced the Board in here and I include the exact quote in terms of the Board's view on ANG and Foothills and the usefulness of cost-of-service regulation and I referenced the fact that they said it wasn't material enough to have different capital structure ratios.

10313. So it's a question that the Board felt as -- as I felt at the time, that this does affect risk; it's a question of the materiality of that risk.

10314. **MR. DAVIES:** Now, you go on in this bullet that we have been looking at to say that the only uncertainty is attached to other shippers signing on to the MVP through FST agreements. And on that basis, you recommend a provisional 50 basis points, which you say should be tested at MVP's first general toll hearing.

10315. Are you saying that if other shippers come forward and sign FST agreements, then perhaps the 50 basis point premium should be eliminated?

10316. **DR. BOOTH:** I'm saying there that regulation is a dynamic process and one of the things that I would disagree with compared to the company's application is they tend to take the view that these things are fixed throughout the application, throughout the time period. But what happens is the regulator dynamic is such that as things change, the evaluations change.

10317. And all I'm saying here is that, at this point in time, I can see that there's an element of risk, but there is the possibility that, once the pipeline gets approved, if in fact it comes in -- it may even come in under budget; it might come in under $5 billion and as a result the tolls are lower, and as a result more shippers sign on, that -- and there's more FST contracts, that that would lower the risk of the pipeline.

10318. **MR. DAVIES:** Well, what are you referring to here in terms of the uncertainty being attached to other shippers signing on to the MVP through FST agreements?

10319. What uncertainty are you referring to?

10320. **DR. BOOTH:** At the time of the application, I was thinking there's just a .83 Bcf from the four major proponents and that that didn't seem to be enough to actually get the pipeline up and running.

10321. I think there's a letter from Imperial at one point saying that they needed more FST contracts.

TAB 8

STANDARD & POOR'S RatingsDirect

RESEARCH

New Business Profile Scores Assigned for U.S. Utility and Power Companies; Financial Guidelines Revised

Publication date: 02-Jun-2004
Credit Analyst: Ronald M Barone, New York (1) 212-438-7662; Richard W Cortright, Jr. , New York (1) 212-438-7665; Suzanne G Smith, New York (1) 212-438-2106; John W Whitlock, New York (1) 212-438-7678; Andrew Watt, New York (1) 212-438-7868; Arthur F Simonson, New York (1) 212-438-2094

Standard & Poor's Ratings Services has assigned new business profile scores to U.S. utility and power companies to better reflect the relative business risk among companies in the sector. Standard & Poor's also has revised its published risk-adjusted financial guidelines. The new business scores and financial guidelines do not represent a change to Standard & Poor's ratings criteria or methodology, and no ratings changes are anticipated from the new business profile scores or revised financial guidelines.

New Business Profile Scores and Revised Financial Guidelines

Standard & Poor's has always monitored changes in the industry and altered its business risk assessments accordingly. This is the first time since the 10-point business profile scale for U.S. investor-owned utilities was implemented that a comprehensive assessment of the benefits and the application of the methodology has been made. The principal purpose was to determine if the methodology continues to provide meaningful differentiation of business risk. The review indicated that while business profile scoring continues to provide analytical benefits, the complete range of the 10-point scale was not being utilized to the fullest extent.

Standard & Poor's has also revised the key financial guidelines that it uses as an integral part of evaluating the credit quality of U.S. utility and power companies. These guidelines were last updated in June 1999. The financial guidelines for three principal ratios (funds from operations (FFO) interest coverage, FFO to total debt, and total debt to total capital) have been broadened so as to be more flexible. Pretax interest coverage as a key credit ratio was eliminated.

Finally, Standard & Poor's has segmented the utility and power industry into sub-sectors based on the dominant corporate strategy that a company is pursuing. Standard & Poor's has published a new U.S. utility and power company ranking list that reflects these sub-sectors.

There are numerous benefits to the reassessment. Fuller utilization of the entire 10-point scale provides a superior relative ranking of qualitative business risk. A simultaneous revision of the financial guidelines supports the goal of not causing rating changes from the recalibration of the business profiles. Classification of companies by sub-sectors will ensure greater comparability and consistency in ratings. The use of industry segmentation will also allow more in-depth statistical analysis of ratings distributions and rating changes.

The reassessment does not represent a change to Standard & Poor's criteria or methodology for determining ratings for utility and power companies. Each business profile score should be considered as the assignment of a new score; these scores do not represent improvement or deterioration in our assessment of an individual company's business risk relative to the previously assigned score. The financial guidelines continue to be risk-adjusted based on historical utility and industrial medians. Segmentation into industry sub-sectors does not imply that specific company characteristics will not weigh heavily into the assignment of a company's business profile score.

Results

Previously, 83% of U.S. utility and power business profile scores fell between '3' and '6', which clearly does not reflect the risk differentiation that exists in the utility and power industry today. Since the 10-point scale was introduced, the industry has transformed into a much less homogenous industry, where the divergence of business risk--particularly regarding management, strategy, and degree of competitive market exposure--has created a much wider spectrum of risk profiles. Yet over the same period, business profile scores actually converged more tightly around a median score of '4'. The new business profile scores, as of the date of this publication, are shown in Chart 1. The overall median business profile score is now '5'.

Chart 1

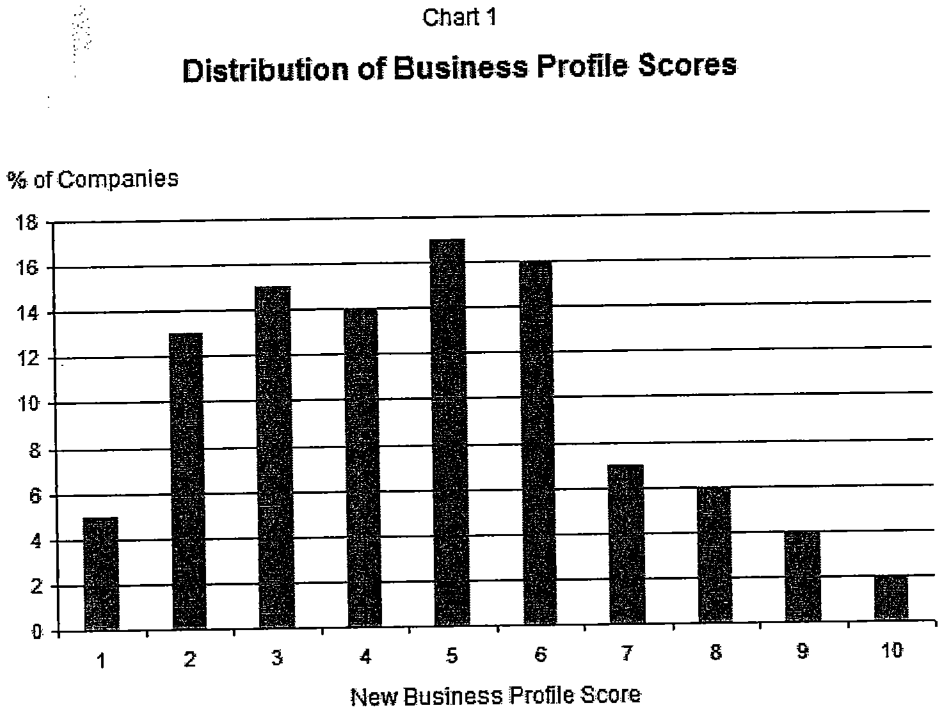


Table 1 contains the revised financial guidelines. It is important to emphasize that these metrics are only guidelines associated with expectations for various rating levels. Although credit ratio analysis is an important part of the ratings process, these three statistics are by no means the only critical financial measures that Standard & Poor's uses in its analytical process. We also analyze a wide array of financial ratios that do not have published guidelines for each rating category.

Table 1

Revised Financial Guidelines

Funds from operations/interest coverage (x)

Business Profile	AA		A		BBB		BB	
1	3	2.5	2.5	1.5	1.5	1		
2	4	3	3	2	2	1		
3	4.5	3.5	3.5	2.5	2.5	1.5	1.5	1
4	5	4.2	4.2	3.5	3.5	2.5	2.5	1.5
5	5.5	4.5	4.5	3.8	3.8	2.8	2.8	1.8
6	6	5.2	5.2	4.2	4.2	3	3	2
7	8	6.5	6.5	4.5	4.5	3.2	3.2	2.2

Table 1

Revised Financial Guidelines (cont.)

8	10	7.5	7.5	5.5	5.5	3.5	3.5	2.5
9			10	7	7	4	4	2.8
10			11	8	8	5	5	3

Funds from operation/total debt (%)

Business Profile	AA		A		BBB		BB	
1	20	15	15	10	10	5		
2	25	20	20	12	12	8		
3	30	25	25	15	15	10	10	5
4	35	28	28	20	20	12	12	8
5	40	30	30	22	22	15	15	10
6	45	35	35	28	28	18	18	12
7	55	45	45	30	30	20	20	15
8	70	55	55	40	40	25	25	15
9			65	45	45	30	30	20
10			70	55	55	40	40	25

Total debt/total capital (%)

Business Profile	AA		A		BBB		BB	
1	48	55	55	60	60	70		
2	45	52	52	58	58	68		
3	42	50	50	55	55	65	65	70
4	38	45	45	52	52	62	62	68
5	35	42	42	50	50	60	60	65
6	32	40	40	48	48	58	58	62
7	30	38	38	45	45	55	55	60
8	25	35	35	42	42	52	52	58
9			32	40	40	50	50	55
10			25	35	35	48	48	52

Again, ratings analysis is not driven solely by these financial ratios, nor has it ever been. In fact, the new financial guidelines that Standard & Poor's is incorporating for the specified rating categories reinforce the analytical framework whereby other factors can outweigh the achievement of otherwise acceptable financial ratios. These factors include:

- Effectiveness of liability and liquidity management;
- Analysis of internal funding sources;
- Return on invested capital;
- The record of execution of stated business strategies;
- Accuracy of projected performance versus actual results, as well as the trend;
- Assessment of management's financial policies and attitude toward credit; and
- Corporate governance practices.

Charts 2 through 6 show business profile scores broken out by industry sub-sector. The five industry sub-sectors are:

- Transmission and distribution--Water, gas, and electric;
- Transmission only--Electric, gas, and other;
- Integrated electric, gas, and combination utilities;

- Diversified energy and diversified nonenergy; and
- Energy merchant/power developer/trading and marketing companies.

Chart 2

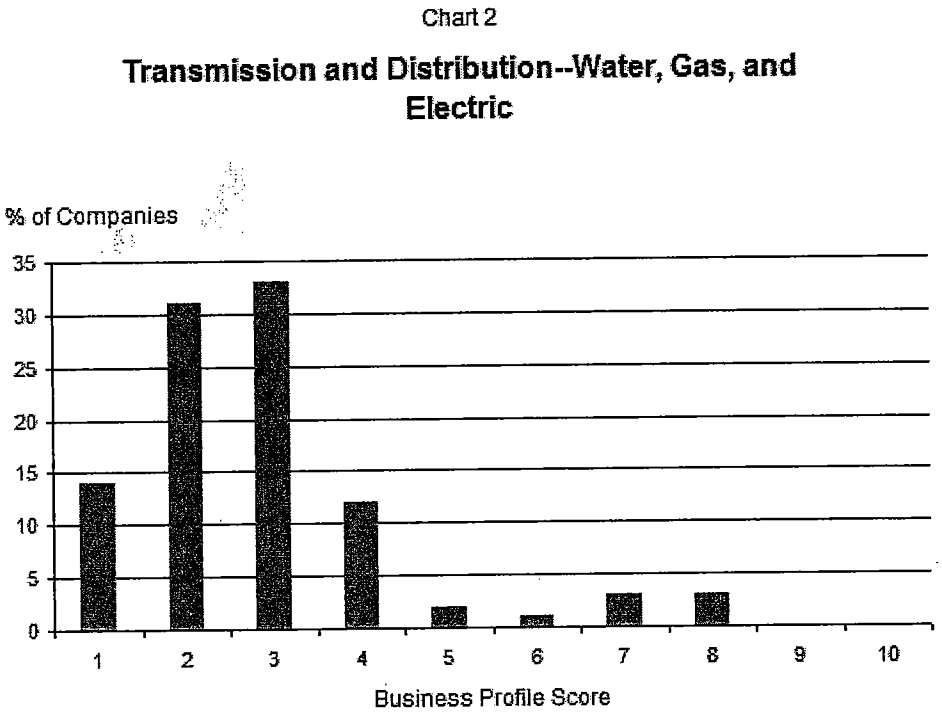


Chart 3

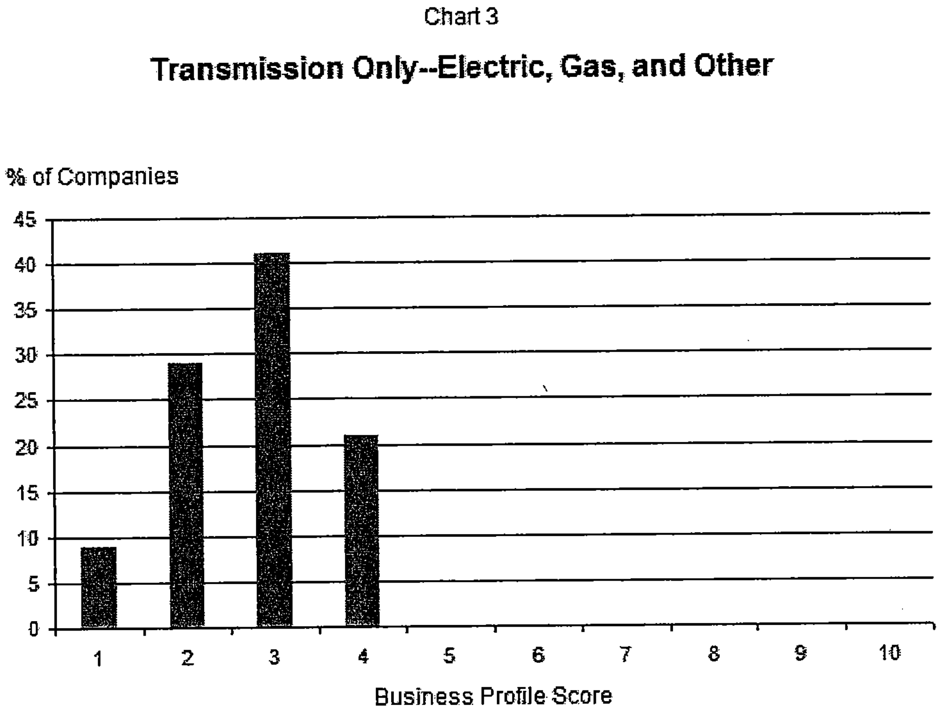


Chart 4

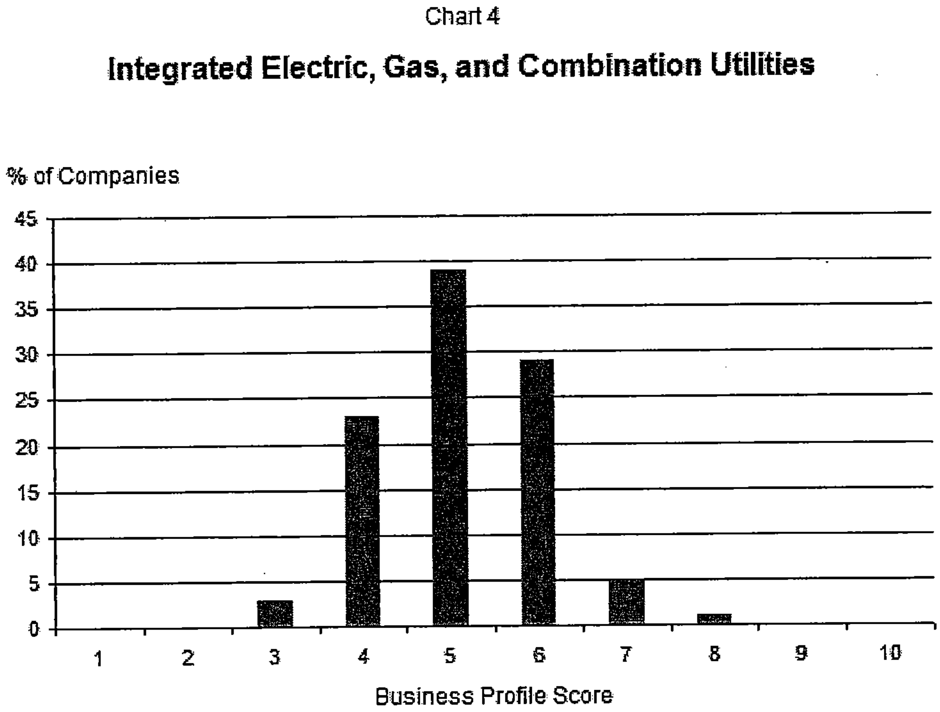


Chart 5

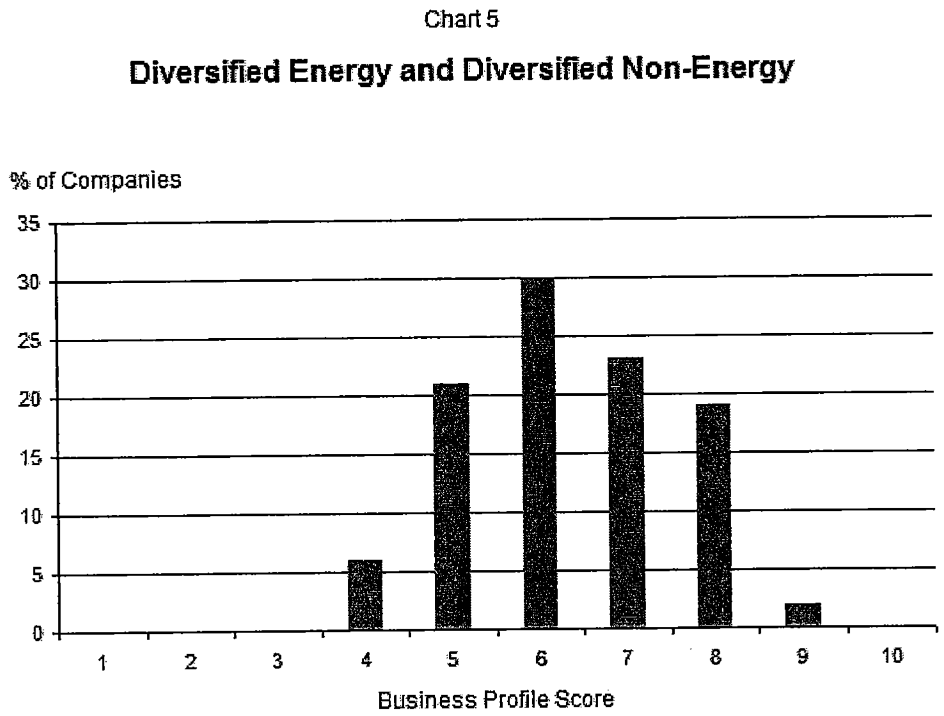
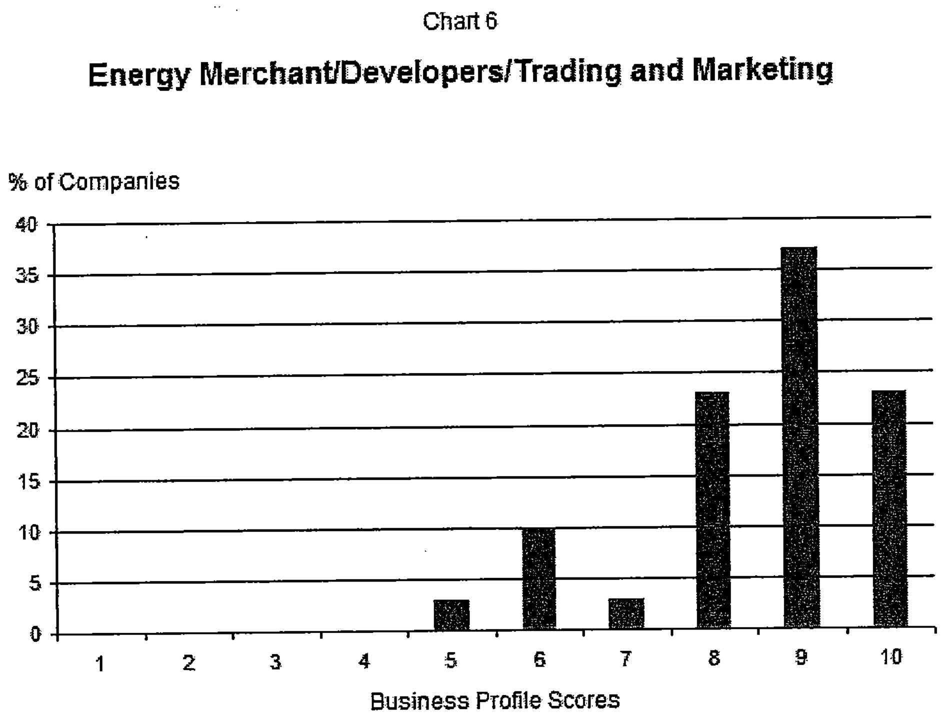


Chart 6



The average business profile scores for transmission and distribution companies and transmission-only companies are lower on the scale than the previous averages, while the average business profile scores for integrated utilities, diversified energy, and energy merchants and developers are higher.

The Appendix provides the company list of business profile scores segmented by industry sub-sector and ranked in order of credit rating, outlook, business profile score, and relative strength.

Business Profile Score Methodology

Standard & Poor's methodology of determining corporate utility business risk is anchored in the assessment of certain specific characteristics that define the sector. We assign business profile scores to each of the rated companies in the utility and power sector on a 10-point scale, where '1' represents the lowest risk and '10' the highest risk. Business profile scores are assigned to all rated utility and power companies, whether they are holding companies, subsidiaries or stand-alone corporations. For operating subsidiaries and stand-alone companies, the score is a bottom-up assessment. Scores for families of companies are a composite of the operating subsidiaries' scores. The actual credit rating of a company is analyzed, in part, by comparing the business profile score with the risk-adjusted financial guidelines.

For most companies, business profile scores are assessed using five categories; specifically, regulation, markets, operations, competitiveness, and management. The emphasis placed on each category may be influenced by the dominant strategy of the company or other factors. For example, for a regulated transmission and distribution company, regulation may account for 30% to 40% of the business profile score because regulation can be the single-most important credit driver for this type of company. Conversely, competition, which may not exist for a transmission and distribution company, would provide a much lower proportion (e.g., 5% to 15%) of the business profile score.

For certain types of companies, such as power generators, power developers, oil and gas exploration and production companies, or nonenergy-related holdings, where these five components may not be appropriate, Standard & Poor's will use other, more appropriate methodologies. Some of these companies are assigned business profile scores that are useful only for relative ranking purposes.

As noted above, the business profile score for a parent or holding company is a composite of the business profile scores of its individual subsidiary companies. Again, Standard & Poor's does not apply rigid guidelines for determining the proportion or weighting that each subsidiary represents in the overall business profile score. Instead, it is determined based on a number of factors. Standard & Poor's will analyze each subsidiary's contribution to FFO, forecast capital expenditures, liquidity requirements, and other parameters, including the extent to which one subsidiary has higher growth. The weighting is determined case-by-case.

Appendix: U.S. Utility and Power Company Ranking List

U.S. Utility and Power Company Ranking List

Company	Corporate Credit Rating	Business Profile
1. Regulated Transmission and Distribution - Electric, Gas, and Water		
Baton Rouge Water Works Co. (The)	AA/Stable/--	1
Nicor Gas Co.	AA/Stable/A-1+	2
Nicor Inc.	AA/Stable/A-1+	3
Washington Gas Light Co.	AA-/Stable/A-1+	2
WGL Holdings Inc.	AA-/Stable/A-1+	3
New Jersey Natural Gas Co.	A+/Stable/A-1	1
Aqua Pennsylvania	A+/Stable/--	2
KeySpan Energy Delivery Long Island	A+/Negative/--	1
KeySpan Energy Delivery New York	A+/Negative/--	1
Elizabethtown Water Co.	A+/Negative/--	2

U.S. Utility and Power Company Ranking List (cont.)

California Water Service Co.	A+/Negative/--	3
Questar Gas Co.	A+/Negative/--	3
Southern California Gas Co.	A/Stable/A-1	1
Boston Edison Co.	A/Stable/A-1	1
Commonwealth Electric Co.	A/Stable/--	1
Cambridge Electric Light Co.	A/Stable/--	1
NSTAR	A/Stable/A-1	1
Massachusetts Electric Co.	A/Stable/A-1	1
Narragansett Electric Co.	A/Stable/A-1	1
Northwest Natural Gas Co.	A/Stable/A-1	1
Connecticut Water Service Inc.	A/Stable/ --	2
Connecticut Water Co. (The)	A/Stable/--	2
Aquarion Co.	A/Stable/--	2
Aquarion Water Co. of Connecticut	A/Stable/--	2
NSTAR Gas Co.	A/Stable/--	2
Piedmont Natural Gas Co. Inc.	A/Stable/A-1	2
National Grid USA	A/Stable/A-1	2
Consolidated Edison Co. of New York Inc.	A/Stable/A-1	2
Orange and Rockland Utilities Inc.	A/Stable/A-1	2
Rockland Electric Co.	A/Stable/--	2
Consolidated Edison Inc.	A/Stable/A-1	2
Laclede Gas Co.	A/Stable/A-1	3
Laclede Group Inc.	A/Stable/--	3
Atlantic City Sewerage Co.	A/Stable/--	3
Niagara Mohawk Power Corp.	A/Stable/--	3
Central Hudson Gas & Electric Co.	A/Stable/--	3
American Water Capital Corp.	A/Negative/	2
Boston Gas Co.	A/Negative/--	2
Colonial Gas Co.	A/Negative/--	2
Middlesex Water Co.	A/Negative/--	3
York Water Co. (The)	A-/Stable/--	2
Alabama Gas Corp.	A-/Stable/--	2
Atlanta Gas Light Co.	A-/Stable/--	2
Public Service Co. of North Carolina Inc.	A-/Stable/A-2	2
Wisconsin Gas Co.	A-/Stable/A-2	2
North Shore Gas Co.	A-/Stable/A-2	2
Peoples Gas Light & Coke Co.	A-/Stable/A-2	2
ONEOK Inc.	A-/Stable/A-2	6
Indiana Gas Co. Inc.	A-/Negative/--	1
Southern California Water Co.	A-/Negative/--	3
American States Water Co.	A-/Negative/--	3
United Water New Jersey	A-/Negative/--	4
United Waterworks	A-/Negative/--	4
PPL Electric Utilities Corp.	A-/Negative/--	4

U.S. Utility and Power Company Ranking List (cont.)

Commonwealth Edison Co.	A-/Negative/A-2	4
PECO Energy Co.	A-/Negative/A-2	4
Central Illinois Public Service Co.	A-/CW-Neg/--	3
Western Massachusetts Electric Co.	BBB+/Stable/--	1
Cascade Natural Gas Corp.	BBB+/Stable/--	2
South Jersey Gas Co.	BBB+/Stable/--	2
Baltimore Gas & Electric Co.	BBB+/Stable/A-2	3
Connecticut Natural Gas Corp.	BBB+/Negative/--	3
Southern Connecticut Gas Co.	BBB+/Negative/--	3
Central Maine Power Co.	BBB+/Negative/--	3
Atlantic City Electric Co.	BBB+/Negative/A-2	3
Potomac Electric Power Co.	BBB+/Negative/A-2	3
Delmarva Power & Light Co.	BBB+/Negative/A-2	3
Yankee Gas Services Co.	BBB+/Negative/--	3
Connecticut Light & Power Co.	BBB+/Negative/--	3
UGI Utilities Inc.	BBB+/Negative/--	4
Bay State Gas Co.	BBB/Stable/--	2
AEP Texas Central Co.	BBB/Stable/--	2
AEP Texas North Co.	BBB/Stable/--	2
Southwest Gas Corp.	BBB-/Stable/--	3
Columbus Southern Power Co.	BBB/Stable/--	3
Ohio Power Co.	BBB/Stable/--	3
Public Service Electric & Gas Co.	BBB/Stable/A-2	3
Oncor Electric Delivery Co.	BBB/Negative/--	2
Southern Union Co.	BBB/Negative/--	3
Centerpoint Energy Houston Electric LLC	BBB/Negative/--	3
CenterPoint Energy Resources Corp.	BBB/Negative/--	3
Duquesne Light Co.	BBB/Negative/	4
Duquesne Light Holdings Inc.	BBB/Negative/ --	5
TXU Gas Co.	BBB/CW-Dev/--	3
Jersey Central Power & Light Co.	BBB-/Stable/--	4
Metropolitan Edison Co.	BBB-/Stable/--	4
Pennsylvania Electric Co.	BBB-/Stable/--	4
Texas-New Mexico Power Co.	BB+/Stable/--	4
AmeriGas Partners L.P.	BB+/Stable/--	7
NUI Utilities Inc.	BB/CW-Dev/--	4
Suburban Propane Partners L.P.	BB-/Stable/--	8
Star Gas Partners L.P.	BB-/Stable/--	8
SEMCO Energy Inc.	BB-/Negative/--	5
Ferrellgas Partners L.P.	BB-/Negative/--	8
Potomac Edison Co.	B/Stable/--	3
West Penn Power Co.	B/Stable/--	3
Illinova Corp.	B/Negative/--	7
NorthWestern Corp.	D/NM/--	7

U.S. Utility and Power Company Ranking List (cont.)

2. Transmission Only - Electric, Gas, and Other

Questar Pipeline Co.	A+/Negative/--	3
Mid-West Independent Transmission System Operator Inc.	A/Stable/--	1
American Transmission Co.	A/Stable/A-1	1
New England Power Co.	A/Stable/A-1	1
Colonial Pipeline Co.	A/Stable/A-1	3
Dixie Pipeline Co.	--/--/A-1	3
Plantation Pipeline Co.	--/--/A-1	3
Explorer Pipeline Co.	A/Stable/A-1	4
Northern Natural Gas Co.	A-/Positive/--	2
Buckeye Partners L.P.	A-/Stable/--	4
Kern River Gas Transmission Co.	A-/Negative/--	3
Northern Border Pipeline Co.	A-/CW-Neg/--	2
Texas Gas Transmission LLC	BBB+/Stable/--	3
Iroquois Gas Transmission System L.P.	BBB+/Stable/--	3
Florida Gas Transmission Co.	BBB/Stable/--	2
International Transmission Co.	BBB/Stable	2
ITC Holding Corp.	BBB/Stable	2
Texas Eastern Transmission L.P.	BBB/Stable/--	3
PanEnergy Corp.	BBB/Stable/--	3
TE Products Pipeline Co. L.P.	BBB/Stable/--	4
TEPPCO Partners L.P.	BBB/Stable/--	4
Panhandle Eastern Pipeline LLC	BBB/Negative/--	3
Noark Pipeline Finance LLC	BBB/Negative/--	4
Southern Star Central Gas Pipeline Inc.	BB/Stable/--	3
Transwestern Pipeline Co.	BB/CW-Dev/--	4
Transcontinental Gas Pipe Line Corp.	B+/Negative/--	2
Northwest Pipeline Corp.	B+/Negative/--	2
Colorado Interstate Gas Co.	B-/Negative/--	2
Southern Natural Gas Co.	B-/Negative/--	2
ANR Pipeline Co.	B-/Negative/--	3
Tennessee Gas Pipeline Co.	B-/Negative/--	3
El Paso Tennessee Pipeline Co.	B-/Negative/--	3
El Paso Natural Gas Co.	B-/Negative/--	4
Gas Transmission-Northwest Corp.	CC/CW-Pos/--	2

3. Integrated Electric, Gas, and Combination Utilities

Wisconsin Public Service Corp.	AA-/Stable/A-1+	4
Madison Gas & Electric Co.	AA/Negative/A-1+	4
Southern Co.	A/Stable/A-1	4
Georgia Power Co.	A/Stable/A-1	4
Alabama Power Co.	A/Stable/A-1	4
Mississippi Power Co.	A/Stable/A-1	4
Gulf Power Co.	A/Stable/--	4

U.S. Utility and Power Company Ranking List (cont.)

Savannah Electric & Power Co.	A/Stable/–	4
San Diego Gas & Electric Co.	A/Stable/A-1	5
MidAmerican Energy Co.	A/Stable/A-1	5
Questar Corp.	–/--/A-1	6
Equitable Resources Inc.	A/Stable/A-1	6
Florida Power & Light Co.	A/Negative/A-1	4
South Carolina Electric & Gas Co.	A-/Stable/A-2	4
SCANA Corp.	A-/Stable/–	4
Wisconsin Electric Power Co.	A-/Stable/A-2	4
AGL Resources Inc.	A-/Stable/A-2	4
Virginia Electric & Power Co. (Dominion Virginia)	A-/Stable/A-2	5
Idaho Power Co.	A-/Stable/A-2	5
IDACORP Inc.	A-/Stable/A-2	5
Energen Corp.	A-/Stable/–	6
Vectren Utility Holdings Inc.	A-/Negative/A-2	3
Wisconsin Power & Light Co.	A-/Negative/A-2	4
Atmos Energy Corp.	A-/Negative/A-2	4
Southern Indiana Gas & Electric Co.	A-/Negative/--	5
Montana-Dakota Utilities Co.	A-/Negative/--	5
PacifiCorp	A-/Negative/A-2	5
Northern Border Partners L.P.	A-/CW-Neg/–	4
Central Illinois Light Co.	A-/CW-Neg/--	5
CILCORP	A-/CW-Neg/--	5
Union Electric Co.	A-/CW-Neg/A-2	5
Ameren Corp.	A-/CW-Neg/A-2	5
Cincinnati Gas & Electric Co.	BBB+/Stable/A2-	4
Oklahoma Gas & Electric Co.	BBB+/Stable/A-2	4
Northern States Power Wisconsin	BBB+/Stable /A-2	5
Kentucky Utilities Co.	BBB+/Stable/A-2	5
Louisville Gas & Electric Co.	BBB+/Stable/A-2	5
Allete Inc.	BBB+/Stable/A-2	5
Wisconsin Energy Corp.	BBB+/Stable/A-2	5
PSI Energy Inc.	BBB+/Stable/A-2	5
Union Light Heat & Power Co.	BBB+/Stable/--	5
Hawaiian Electric Co. Inc.	BBB+/Stable/A-2	6
Enogex Inc.	BBB+/Stable/--	6
National Fuel Gas Co.	BBB+/Stable/A-2	7
Energy East Corp.	BBB+/Negative/--A2	3
RGS Energy Group Inc.	BBB+/Negative/–	4
Rochester Gas & Electric Corp.	BBB+/Negative/–	4
Michigan Consolidated Gas Co.	BBB+/Negative/A-2	4
Interstate Power & Light Co.	BBB+/Negative/A-2	5
Public Service Co. of New Hampshire	BBB+/Negative/–	5
Kaneb Pipe Line Operating Partnership L.P.	BBB+/Negative/--	5

U.S. Utility and Power Company Ranking List (cont.)

Consolidated Natural Gas Co.	BBB+/Negative/A-2	6
Detroit Edison Co.	BBB+/Negative/A-2	6
Questar Market Resources Inc.	BBB+/Negative/–	8
Portland General Electric Co.	BBB+/CW-Neg./A-2	5
Columbia Energy Group	BBB/Stable/–	3
NiSource Inc.	BBB/Stable/–	4
Xcel Energy Inc.	BBB/Stable/A-2	5
Public Service Co. of Colorado	BBB/Stable /A-2	5
Northern States Power Co.	BBB/Stable /A-2	5
Southwestern Public Service Co.	BBB/Stable /A-2	5
Appalachian Power Co.	BBB/Stable/–	5
Kentucky Power Co.	BBB/Stable/--	5
Public Service Co. of Oklahoma	BBB/Stable/–	5
Southwestern Electric Power Co.	BBB/Stable/–	5
Northern Indiana Public Service Co.	BBB/Stable/--	5
Entergy Arkansas Inc.	BBB/Stable/–	5
Entergy Louisiana Inc.	BBB/Stable/–	5
Progress Energy Florida	BBB/Stable/–	5
Progress Energy Carolinas Inc.	BBB/Stable/A-2	5
Kansas City Power & Light Co.	BBB/Stable/A-2	6
PNM Resources Inc.	BBB/Stable/–	6
Southern California Edison Co.	BBB/Stable/A-2	6
Empire District Electric Co.	BBB/Stable/A-2	6
Entergy Mississippi Inc.	BBB/Stable/–	6
Entergy New Orleans Inc.	BBB/Stable/–	6
Duke Energy Field Services LLC	BBB/Stable/A-2	6
Arizona Public Service Co.	BBB/Negative/A-2	5
TXU U.S. Holdings Co.	BBB/Negative/--	5
Pinnacle West Capital Corp.	BBB/Negative/A-2	6
Cleco Power LLC	BBB/Negative/A-3	6
Puget Sound Energy Inc.	BBB-/Positive/A-3	5
Puget Energy Inc.	BBB-/Positive/–	5
Green Mountain Power Corp.	BBB-/Stable/--	5
Public Service Co. of New Mexico	BBB-/Stable/A-2	6
Pacific Gas & Electric Co.	BBB-/Stable/ –	6
Cleveland Electric Illuminating Co.	BBB-/Stable/--	6
Ohio Edison Co.	BBB-/Stable/--	6
Toledo Edison Co.	BBB-/Stable/--	6
Pennsylvania Power Co.	BBB-/Stable/--	6
El Paso Electric Co.	BBB-/Stable/--	6
Central Vermont Public Service Corp.	BBB-/Stable/--	6
Entergy Gulf States Inc.	BBB-/Stable/--	6
System Energy Resources Inc.	BBB-/Stable/--	7
Tampa Electric Co.	BBB-/Negative/A-3	4

U.S. Utility and Power Company Ranking List (cont.)

Black Hills Power Inc.	BBB-/Negative/--	6
Westar Energy Inc.	BB+/Positive/--	5
Kansas Gas & Electric Co.	BB+/Positive/--	6
Indianapolis Power & Light Co.	BB+/Stable/--	4
IPALCO Enterprises Inc.	BB+/Stable/--	4
Enterprise Products Operating L.P.	BB+/Stable/--	6
Enterprise Products Partners L.P.	BB+/Stable/--	6
GulfTerra Energy Partners L.P.	BB+/CW-Neg/--	6
Consumers Energy Co.	BB/Negative/--	6
Tucson Electric Power Co.	BB/CW-Neg/--	6
Dayton Power & Light Co.	BB-/CW-Neg/--	7
Monongahela Power Co.	B/Stable/--	5
Nevada Power Co.	B+/Negative/--	7
Sierra Pacific Power Co.	B+/Negative/--	7
Sierra Pacific Resources	B+/Negative/--	7

4. Diversified Energy and Diversified Non-Energy

WPS Resources Corp.	A/Stable/A-1	5
KeySpan Corp.	A/Negative/A-1	4
FPL Group Inc.	A/Negative/--	6
Peoples Energy Corp.	A-/Stable/A-2	5
Vectren Corp.	A-/Negative/--	4
PacifiCorp Holdings Inc.	A-/Negative/--	5
Exelon Corp.	A-/Negative/A-2	7
MDU Resources Group Inc.	A-/Negative/A-2	7
Centennial Energy Holdings Inc.	A-/Negative/A-2	8
Otter Tail Corp.	A-/Negative/--	8
Kinder Morgan Energy Partners L.P.	BBB+/Stable/A-2	4
Northeast Utilities	BBB+/Stable/--	5
OGE Energy Corp.	BBB+/Stable/A-2	6
LG&E Energy Corp.	BBB+/Stable/--	6
Cinergy Corp.	BBB+/Stable/A-2	6
Constellation Energy Group Inc.	BBB+/Stable/A-2	7
Sempra Energy	BBB+/Stable/A-2	7
Pepco Holdings Inc.	BBB+/Negative/A-2	5
Conectiv	BBB+/Negative/--	5
Alliant Energy Corp.	BBB+/Negative/A-2	6
DTE Energy Co.	BBB+/Negative/A-2	6
Dominion Resources Inc.	BBB+/Negative/A-2	7
Kinder Morgan Inc.	BBB/Stable/A-2	5
American Electric Power Co. Inc.	BBB/Stable/A-2	6
Entergy Corp.	BBB/Stable/--	6
Hawaiian Electric Industries Inc.	BBB/Stable/A-2	6
Progress Energy Inc.	BBB/Stable/A-2	6

U.S. Utility and Power Company Ranking List (cont.)

PPL Corp.	BBB/Stable/--	7
Public Service Enterprise Group Inc.	BBB/Stable/A-2	7
Great Plains Energy Inc.	BBB/Stable/--	7
Duke Energy Corp.	BBB/Stable/A-2	7
Duke Capital Corp.	BBB/Stable/A-2	8
TXU Corp.	BBB/Negative/--	5
Centerpoint Energy Inc.	BBB/Negative/--	5
Cleco Corp.	BBB/Negative/A-3	6
Potomac Capital Investment Corp.	BBB/Negative/--	8
MidAmerican Energy Holdings Co.	BBB-/Positive/--	5
FirstEnergy Corp.	BBB-/Stable/--	6
TECO Energy Inc.	BBB-/Negative/A-3	5
Black Hills Corp.	BBB-/Negative/--	8
Avista Corp.	BB+/Stable/--	6
Edison International	BB+/Stable/--	6
TNP Enterprises	BB+/Stable/--	6
New York Water Service Corp.	BB/Stable	7
CMS Energy Corp.	BB/Negative/--	7
DPL Inc.	BB- /CW-Neg/--	8
Williams Companies Inc. (The)	B+/Negative/--	8
Allegheny Energy Inc.	B/Stable/--	7
Dynegy Inc.	B/Negative/--	8
Dynegy Holdings Inc.	B/Negative/--	9
El Paso CGP Corp.	B-/Negative/--	6
Aquila Inc.	B-/Negative/--	8
El Paso Corp.	B-/Negative/--	8

5. Energy Merchants/Power Developers/Trading and Marketing

Entergy-Koch L.P.	A/Stable/--	9
KeySpan Generation LLC	A/Negative/--	5
FPL Group Capital	A/Negative/A-1	8
Exelon Generation Co.	A-/Negative/A-2	8
AmerenEnergy Generating Co.	A-/CW-Neg/--	8
Southern Power Co.	BBB+/Stable/--	6
LG&E Capital Corp.	BBB+/Stable/A-2	9
Alliant Energy Resources Inc.	BBB+/Negative/--	9
American Ref-Fuel Co. LLC	BBB/Stable/--	6
PSEG Power LLC	BBB/Stable/--	8
PPL Energy Supply LLC	BBB/Stable/--	8
TXU Energy Co. LLC	BBB/Negative/--	7
Duke Energy Trading and Marketing LLC	BBB-/Negative/--	10
Northeast Generation Company	BB+/Negative/--	9
Cogentrix Energy	BB-/Stable/--	6
PSEG Energy Holdings Inc.	BB-/Stable/--	9

U.S. Utility and Power Company Ranking List (cont.)

AES Corp.	B+/Stable/--	9
NRG Energy Inc.	B+/Stable	9
Allegheny Energy Supply Co. LLC	B/Stable/--	8
Reliant Resources Inc.	B/Negative/--	8
Calpine Corp	B/Negative/--	9
Edison Mission Energy	B/Negative/--	9
Orion Power Holdings Inc	B/Negative/--	9
Reliant Energy Mid-Atlantic Power Holdings LLC	B/Negative/–	9
Mirant Americas Generation Inc.	D/--/--	10
Mirant Americas Energy Marketing L.P.	D/--/--	10
Mirant Corp.	D/--/--	10
NEGT Energy Trading Holdings Corp	D/--/--	10
PG&E National Energy Group	D/--/--	10
USGen New England Inc.	D/--/--	10

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TAB 9

	Total Preferds O/S	Total Preferds Issued 2001 to date	Total Preferds Called 2001 to date
Altalink L.P.	$0 M	$0 M	$0 M
Gaz Metro L.P.	$0 M	$0 M	$0 M
Newfoundland Power	$10 M	$0 M	$0 M
Terasen Gas	$75 M	$0 M	$0 M
TransAlta Utilities	$0 M	$0 M	$0 M
TransAlta Corp	$150 M	$150 M	$793 M
Maritime & NE Pipeline	$0 M	$0 M	$0 M
Express Pipeline	$0 M	$0 M	$0 M
Trans-Quebec Maritimes	$0 M	$0 M	$0 M
Trans-Canada Pipelines	$1,060 M	$0 M	$360 M
Union Gas	$20 M	$0 M	$0 M
Westcoast	$425 M	$0 M	$680 M
ATCO/Canadian Utilities*	$150 M	$150 M	$0 M
Emera*	$260 M	$0 M	$63 M
Enbridge (all)	$230 M	$0 M	$550 M
TOTAL INDUSTRY	$2,380 M	$300 M	$2,446 M

All data from Bloomberg. Does not include USD issues.
*Includes convertible preffered shares.

Scotia Capital™

TAB 10

	Total Canadian Issuance 2001 to date	Secured Issuance 2001 to date	% Secured of Total Issuance	Total All Debt Outstanding	Total Secured Outstanding
Altalink L.P.	$575 M	$575 M	100%	$575 M	$575 M
Gaz Metro L.P.	$425 M	$425 M	100%	$1,025 M	$1,025 M
Newfoundland Power	$135 M	$135 M	100%	$425 M	$425 M
Terasen Gas	$420 M	$0 M	0%	$2,093 M	$75 M
TransAlta Utilities	$0 M	$0 M	0%	$60 M	$60 M
TransAlta Corp	$341 M	$0 M	0%	$881 M	$0 M
Maritime & NE Pipeline	$0 M	$0 M	0%	$260 M	$260 M
Express Pipeline	$0 M	$0 M	0%	$0 M	$0 M
Trans-Quebec Maritimes	$75 M	$75 M	100%	$275 M	$275 M
Trans-Canada Pipelines	$1,702 M	$0 M	0%	$6,854 M	$0 M
Union Gas	$940 M	$0 M	0%	$2,200 M	$0 M
Westcoast	$209 M	$0 M	0%	$1,659 M	$0 M
ATCO/Canadian Utilities	$1,460 M	$0 M	0%	$675 M	$0 M
Emera	$635 M	$0 M	0%	$1,170 M	$0 M
Enbridge (all)	$2,860 M	$0 M	0%	$5,409 M	$0 M
TOTAL INDUSTRY	$9,777 M	$1,210 M	11%	$23,561 M	$2,695 M

All data from Bloomberg. Does not include USD issues.

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K12.5

BRITISH COLUMBIA UTILITIES COMMISSION

IN THE MATTER OF

BC GAS UTILITY LTD.

1994/95 Revenue Requirements Application
PHASE 2

DECISION

August 4, 1994

Ontario Energy Board
FILE No. EB-2006-0034
EXHIBIT No. K12.5
DATE February 20, 2007
08/99

BEFORE:

Dr. M.K. Jaccard, Chairperson
F.C. Leighton, Commissioner

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EXECUTIVE SUMMARY

This Decision of the British Columbia Utilities Commission deals with Phase 2 of the hearing concerning the BC Gas Utility Ltd. ("BC Gas") Revenue Requirements Application for 1994 and 1995. Phase 1 of the hearing commenced May 2, 1994, and dealt with several elements of a requested rate increase to captive customers. The Commission, by Order No. G-29-94, rescheduled the examination of certain other issues, such as the Integrated Resource Plan ("IRP"), revenue forecasts, and revenue stabilization, as separate phases of the hearing. The Commission issued a Phase 1 Decision on June 16, 1994 which contained the Commission's findings on the Phase 1 issues, including acceptance of a negotiated settlement on capital additions and operating and maintenance expenditures.

Phase 2 of the hearing commenced on June 6, 1994 and dealt with the BC Gas sales and revenue forecasts, a proposal for a Rate Stabilization Adjustment Mechanism, and an evaluation of full decoupling mechanisms. Phase 3 of the hearing examined the BC Gas IRP, Demand-Side Management proposals, and main extension policy.

In this, the Phase 2 Decision, the Commission confirmed the following:

1. The Revenue Stabilization Adjustment Mechanism ("RSAM") proposed by BC Gas is accepted with the exception of the 5 percent 'deadband'. BC Gas is directed to implement the RSAM with no deadband (in other words, a 'zero percent' deadband). In order to mitigate year-to-year rate fluctuations for consumers, the Utility is to file, by October 31, 1994, a proposal for amortizing the deferral account balances of both the RSAM and the Gas Cost Reconciliation Account over a three-year period.

2. BC Gas is directed to develop a proposal for Demand-Side Management ("DSM") incentive mechanisms appropriate for BC Gas, in time for consultation and review by intervenors and other stakeholders prior to filing with the Commission by December 31, 1994.

3. Although the Commission's direction to BC Gas to implement an RSAM with a zero deadband reduces much of the contentiousness surrounding the short-term sales forecasts, the Commission gave careful consideration to the forecasting methodology and to the price elasticity estimates included in the sales and revenue forecasts. The Commission concluded that it could not accept the price elasticity estimates of BC Gas and directed the Utility to exclude those adjustments from the forecasts included in the current Application.

4. During the hearing, a working committee report and recommendations on certain controversial accounting issues was submitted. As the guidelines applied to, and were agreed to, by other gas utilities, and as BC Gas agreed with the guidelines and no intervenor raised any issue with them during the hearing, the Commission as a whole approved the recommendations and guidelines separately prior to this Decision. BC Gas is directed, however, to conduct a study on overhead capitalization methodologies and to file a report with the Commission before September 30, 1995.

1.0 BACKGROUND

1.1 BC Gas Utility Ltd.

BC Gas Utility Ltd. ("BC Gas", "the Utility", the "Company" or "the Applicant") is a natural gas distribution utility providing gas sales or transportation service to over 666,000 residential, commercial and industrial customers in British Columbia. BC Gas Utility Ltd. was formed in July 1993, when the gas utility assets were separated from the non-regulated business ("NRB") assets of BC Gas Inc. which had encompassed both regulated utility assets and NRB assets. Subsequent to this change, BC Gas Inc. became the legal name of the holding company which holds 100 percent of both utility and non-utility assets. For a more complete summary of the corporate structure of BC Gas and its history, the reader is directed to the Decision concerning Phase 1 of the BC Gas 1994/95 Revenue Requirements Hearing.

1.2 Application

On November 22, 1993, BC Gas filed a 1994 and 1995 Revenue Requirements Application ("the Application") which sought interim and permanent rates for 1994 and 1995, pursuant to Sections 64, 67 and 106 of the Utilities Commission Act ("the Act") for all divisions except Fort Nelson. The Application also sought a 3.63 percent increase on captive rates in 1994 and a further 5.73 percent increase on captive rates for 1995, based in part on forecast total sales and transportation service volumes of 226,892 TJ for 1994 and 227,695 TJ for 1995. This portion of the Application was dealt with by the Phase 1 Revenue Requirements Decision of June 16, 1994.

In the Application, the Utility also requested approval of a revenue stabilization adjustment mechanism ("RSAM") effective January 1, 1994, which would stabilize the Company's margin from variances between the actual and forecast use-per-account for residential and commercial customers during the months of November to March. This part of the Application became the subject of Phase 2 of the 1994/95 Revenue Requirement hearing to which this Decision pertains.

2.0 REVENUE STABILIZATION ADJUSTMENT MECHANISM ("RSAM")

2.1 Background

Prior to its April 15, 1994 Phase B Rate Design Application, BC Gas had applied for approval of a Weather Stabilization Adjustment Mechanism ("WSAM") which was intended to mitigate the impact of abnormal weather on the Utility's revenues. BC Gas subsequently asked to withdraw the WSAM. The Commission approved the request by Order No. G-33-93, and directed the Utility to bring forward a modified WSAM or other mechanism in the Phase B Rate Design Hearing. During the Phase B hearing, BC Gas raised a motion to withdraw decoupling and WSAM as issues in the hearing. The Commission accepted the motion but, in its Phase B Rate Design Decision, directed the Company to implement, at a minimum, a WSAM effective January 1, 1994, and to bring forward a full decoupling proposal in time for its next revenue requirements hearing. Consequently, the issues of revenue stabilization and revenue decoupling were dealt with during Phase 2 of the 1994/95 Revenue Requirements hearing.

2.2 The BC Gas RSAM Proposal and Decoupling Position

The current BC Gas RSAM proposal follows the Utility's previous WSAM proposal and the Commission's directive in the Phase B Decision that BC Gas implement some form of WSAM by January 1, 1994. BC Gas filed its RSAM proposal with its Revenue Requirements Application. The Utility chose not to file a decoupling proposal, but instead offered an evaluation of full decoupling.

The BC Gas proposed RSAM would stabilize the Company's revenues by placing in a deferral account any variance in winter revenues from the residential and commercial customers that was above or below forecast by more than 5 percent. Debate centered around the desirability of this 5 percent 'deadband'. Although utilities have traditionally absorbed the risk associated with abnormal weather patterns, the BC Gas RSAM proposal in this hearing was linked to the increased revenue volatility resulting from seasonal rates. BC Gas indicated during the hearing that the 5 percent deadband was intended to return the utility to normal levels of risk for a gas utility.

Several alternatives to the RSAM proposed by BC Gas were discussed in evidence and in testimony during the hearing. These alternatives to the RSAM as applied for included:

- no stabilization mechanism (the status quo),
- RSAM with a modified deadband (0 to 4 percent),
- full decoupling.

2.2.1 The RSAM Deadband

Considerable discussion took place around the desirability and appropriate size of a deadband on the RSAM mechanism. The Company's position was that the volatility of seasonal rates required a revenue stabilization mechanism, but that no RSAM would be preferable to an RSAM with a modified deadband, i.e. anything other than plus or minus five percent (T7: 734-735).

Key issues related to the deadband proposal were the relationship between the width of the deadband, the resulting size of deferral accounts and the potential impact on the year-to-year volatility of rates. A

5 percent deadband would tend to lead to fewer and smaller deferral account accruals and, therefore, the Company argued, would have a smaller impact on rates. Some parties questioned whether deferral account balances would not tend to reach zero over time, as weather variations would tend to vary both above and below normal.

A second issue related to the deadband proposal was whether or not the absence of a deadband would compensate for any intentional or accidental bias in the Utility's revenue forecasting. No party to the hearing suggested or offered any evidence to suggest that intentional 'gaming' of the revenue forecasts had occurred or was currently taking place. However, considerable discussion took place as to whether eliminating any revenue impact from incorrect use-per-account forecasts was sufficient reason of itself to eliminate the deadband.

Mr. Wallace for Celgar Pulp Company, Cominco Ltd. and Weyerhaeuser Canada Ltd. ("Celgar et al.") submitted in argument that the need for, or desirability of, the 5 percent deadband had not been established, and recommended acceptance of the BC Gas RSAM proposal, but with a zero deadband. Mr. Rawlyk for Energy Resources Management ("ERM") also submitted in argument that a 5 percent deadband added "an unnecessary level of complexity" and recommended that an RSAM with a zero deadband be approved, possibly phased-in, beginning with a 5 percent deadband and reducing to a zero deadband after one or two years.

2.2.2 Full Decoupling

In its Phase B Decision (p. 68), the Commission directed BC Gas to file a proposal on the merits of full decoupling for consideration at its next revenue requirements hearing. In its 1994/95 Revenue Requirement Application, BC Gas filed a position on full decoupling which concluded that full decoupling was inappropriate for BC Gas at this time and that the RSAM was preferable to full decoupling. The Consumers' Association of Canada (B.C.) et al ("CAC(BC) et al.") submitted in argument that the Utility had failed to comply with a clear Commission directive in the Phase B Decision to come forward with a full decoupling proposal, and that the Commission should direct the Utility to comply by coming forward with an actual proposal for full decoupling (T15: 1819-20).

The B.C. Energy Coalition ("Energy Coalition") presented a substantial amount of evidence during the hearing in support of decoupling, and submitted that "...a simple decoupling mechanism is the most practical approach for beginning the alignment of shareholder and customer interests" (T15: 1795). During the hearing, the Energy Coalition presented an initial proposal for a decoupling mechanism (Exhibit 68) that included a modification to the existing Gas Cost Reconciliation Account ("GCRA") mechanism, fixed/variable cost-based rates for industrial customers, a revenue per customer decoupling mechanism with a 5 percent weather deadband, and incentives tied to utility performance. However, the Energy Coalition indicated that this was not intended as a definitive decoupling mechanism for BC Gas, but that the Commission should "...establish fundamental guiding principles for a decoupling mechanism, and direct the Company to present a detailed proposal consistent with those guidelines" (T15: 1796-97), and that intervenors and stakeholders should be invited to participate in the development of the proposal (T9: 1076, T15: 1797, 1803).

2.3 Commission Determination

In its application, testimony and final argument, BC Gas maintained that full decoupling of sales from profits is not an *essential* precondition for ensuring that the utility pursues only those sales that are in the best interests of customers and society. The Commission agrees with this assessment. However, a key objective of the Commission is to minimize the need for detailed regulatory control of the utility by ensuring that, wherever possible, the incentives of regulation are aligned with the public interest.

Integrated resource planning shifts the focus of utility regulation from minimizing the cost of commodity provision to minimizing the cost of energy services. The Commission agrees with the Energy Coalition that decoupling distribution utilities' sales from short-run profits should be seen as a regulatory improvement in terms of better aligning regulatory incentives with the public interest. However, the Commission is not convinced that the decoupling proposal of the Energy Coalition is warranted. Instead, the Commission finds itself in agreement with Mr. Wallace (T15: 1809) who suggested that the general objective of decoupling can be largely achieved with the elimination of the 5 percent deadband in the BC Gas RSAM proposal.

In the Commission's view, the RSAM with a zero deadband should have the following beneficial effects.

- The incentive for the Company to pursue short-run sales in the winter period would be eliminated, thereby eliminating the potential conflict between the demand-side pursuit of economically efficient energy services, including fuel-switching and short-run profit maximization for the gas utility.

- An incentive would remain to pursue short-run sales in the summer period, with potential benefits to load factor for the entire system, for core customers in particular.

- Sales forecast risks to utility shareholders would be substantially reduced for sales to the weather sensitive residential and commercial customers throughout the winter period, which represents the major revenue volatility of the Utility.

- Because marginal cost pricing initiatives, such as seasonal rates, would no longer be associated with increased risks for shareholders, utility management would be less reticent to support such improvements.
- The contentiousness associated with regulatory review of short-run energy demand forecasting would be largely eliminated.
- The incentive for the Utility to operate as efficiently as possible at all times would not be diminished relative to the existing regulatory structure.
- The regulatory complexity of implementing the RSAM with zero deadband seems small relative to alternatives that have been discussed (notably ERAM type mechanisms, the previous weather stabilization mechanism of BC Gas and the proposal of the Energy Coalition).

BC Gas expressed a concern that the RSAM with zero deadband could lead to greater year-to-year variability in rates, because the revenue surpluses or shortfalls in any given year would be much higher than with a 5 percent deadband. To probe this issue, BC Gas was asked in the hearing to test alternative time periods for amortization of RSAM surpluses or deficits (T9: 1030-1032). The BC Gas response filed by letter of June 24, 1994 presented one, two and three-year amortization periods with deadbands of 0 percent, 3 percent and 5 percent (the responses for one and three-year periods are attached as Appendix A). The evidence filed by the Utility shows that a three-year amortization period with a 0 percent deadband would not lead to greater variability of rates than would occur under BC Gas' RSAM proposal of a one-year amortization with a 5 percent deadband. BC Gas did not expressly argue against a three-year amortization period, but in testimony and final argument, if did express concern with the use of long amortization periods, noting that the recovery of significant deferral account balances has been a problem in other jurisdictions.

The Commission accepts the BC Gas RSAM proposal, effective January 1, 1994, but with the following modifications. The RSAM will not have a deadband (in other words, it will have a zero deadband). A deferral account balance will accumulate the annual RSAM debits and credits, and one-third of the net balance will be allocated to recovery in applicable rates in the following year so as to minimize the year-to-year variability in rates. BC Gas should come forward, no later than September 15, 1994 with a specific proposal recommending parallel mechanisms to be used for the three-year amortization of both the GCRA and RSAM accounts. This will be circulated to interested parties, and submitted to the Commission for approval by October 31, 1994.

BC Gas is reminded that the Commission's June 10, 1994 Decision in the matter of Return on Common Equity determined that the BC Gas rate of return on equity should be reduced by ten basis points if RSAM (0 percent) was determined in this Decision to be appropriate.

As noted by several intervenors, the issue of decoupling is frequently linked to the provision of appropriate utility incentives for a range of desirable utility services. This Commission intends to approach the development of specific incentive mechanisms with great caution. Any mechanism must be evaluated not just in terms of the potential benefits, but also in terms of the potential costs associated with the difficulty of attaining effective regulatory oversight. Nonetheless, experience in other jurisdictions as well as testimony and argument with respect to RSAM suggest that an incentive mechanism for demand-side management may be desirable for BC Gas. Witnesses for both BC Gas and the Energy Coalition recommended consideration of such mechanisms (Exhibit 3, Tab 2, Page 17 and 18 and Exhibit 57, Page 22).

The Commission directs BC Gas to develop a proposal for demand-side management incentive mechanisms appropriate for BC Gas. The Commission believes consultations with intervenors and other stakeholders are desirable, and suggests the use of the stakeholder collaborative that has already been established for the IRP to review the alternatives before filing the BC Gas proposal with the Commission by December 31, 1994.

3.0 SALES VOLUME AND REVENUE FORECASTS

BC Gas applied for rates based on total forecast gas sales and transportation volumes of 226,892.4 TJ and 227,694.6 TJ for 1994 and 1995, respectively. This was the sum of the demands for different customer classes and was arrived at through several combined methodologies. The Phase 2 hearing provided an opportunity for Commission review of the adequacy of the BC Gas forecasts.

3.1 Industrial Volumes and New Customer Additions

Seasonal and industrial sales and transportation volumes were forecast using a 'bottom-up' approach, by canvassing large volume customers. BC Gas stated during the hearing that the margins on industrial sales were significantly reduced from the past as a result of the increasing transfer of demand charges from industrial to residential/commercial customer classes (T7: 729). The Company also indicated that because of the rate structure of the industrial customers (Exhibit 2, Tab 3), volumetric changes by these customers do not have a large impact on the Company's revenues.

Customer additions on the Lower Mainland, Inland and Columbia systems were forecast to be approximately 21,000 new residential and 2,000 new commercial accounts for each of 1994 and 1995 (Exhibit 1A, Tab 6, Page 1-06-1-018).

No concern was expressed by any intervenor or Commission staff about either forecast of the interruptible sales volumes or new customer additions.

3.2 The Residential and Commercial Sales Volume Forecasts

A key item of debate relating to the residential and commercial sales forecast was the issue of the price elasticity adjustment to the forecast. BC Gas had developed a 'trend' forecast based on historical use versus normal weather over past years and then adjusted that forecast for various non-weather impacts.

The concern for forecasting accuracy is tied to the question of decoupling, as noted in the previous section. If BC Gas' sales revenues are largely decoupled from profits, short-run forecasting error has little effect on the relative gains and losses between shareholders and customers. The Commission Decision to institute an RSAM with a zero deadband thus reduces the importance of forecasting accuracy. Nonetheless, the forecasting method of BC Gas was reviewed in some detail in the hearing, and some challenging questions emerged.

The methodology for developing the 'trend' forecast was explained by Mr. Sanderson (T8: 898-899). The basis of the trend forecast is a regression of 12 months of monthly billed consumption plotted against monthly temperatures, which is used to determine the empirical relationship between consumption and temperature. The 'best fit' curve obtained by that regression is then combined with the ten year normal temperature to calculate the normal use for each month in the 12 months of the forecast. This normal use for each of those 12 months is then summed to provide an annual forecast.

A number of adjustments were made to the trend forecast to account for items such as appliance efficiency legislation, load building programs, Demand-Side Management ("DSM"), price elasticity, and the Utility's Measurement Equity Program. (The Measurement Equity Program refers to the Utility's ongoing change from meters that do not adjust the volume of gas sold to account for the temperature at the time of measurement, to meters that do make that adjustment.) Debate in the hearing concerning adjustments to the trend forecast focused almost exclusively on the price elasticity adjustment, and the econometric methodology used to estimate the magnitude of that adjustment. BC Gas submitted that the methodology was sound and that the estimate should be accepted by the Commission, while others submitted that the estimate was imprecise, or that the evidence supporting the need for a price elasticity adjustment was inconclusive (T15: 1824).

There is little doubt that customers are in some way responsive to price change (price elasticity). The challenge is to attain sound empirical estimates of that response. For this purpose, the regression analysis techniques applied by BC Gas are consistent with some current aggregate applications of econometrics to natural gas demand forecasting. However, scrutiny of the results and methodology seriously undermined the claim that the empirical estimates could be considered sound for the purposes to which they were applied.

The full response to a change in the price of natural gas relative to other energy forms can involve several levels of decisions:

(i) Potential new gas customers may alter their decision about whether or not to acquire natural gas service; this is manifested by a change in the future number of accounts. The commercial market and apartment/townhouse market are most sensitive to this potential. Electricity is the most likely alternative to natural gas in this case, although for single family residences in certain locations, oil, propane or wood may also be alternatives.

(ii) Current gas customers may switch away from natural gas; this response, unlikely at today's prices, also results in a change in the future number of accounts.

(iii) Current customers may marginally substitute between other energy forms and natural gas; this will affect use-per-account. Examples of such decisions are natural gas versus propane for barbecues, natural gas versus wood for fireplaces, natural gas versus electricity for supplemental space heating, and natural gas versus electricity for certain appliances.

(iv) Current customers may marginally substitute between capital and natural gas; this will affect use-per-account. An example is to weatherize or better insulate a house heated by natural gas, or to replace existing natural gas furnaces and appliances with more efficient ones.

(v) Current customers may change their use of existing natural gas equipment; this will affect use-per-account. An example is a decision to lower the thermostat setting in a house heated by natural gas, or on a natural gas domestic water heater.

The time required for each of these responses to manifest itself varies. Response (v) is assumed to occur completely in the short-term. The other four responses are assumed to take much longer, depending on the rate of appliance and heating equipment turnover and of new building construction. For a two-year demand forecast — the issue in this case — the objective is to estimate the full magnitude of Response (v) and the short-term component (i.e. the partial adjustment) of the other four responses.

This is presumably what is estimated by the BC Gas model. However, there appears to be a methodological inconsistency. BC Gas has separated its forecast into two components; changes in number of accounts and changes in use-per-account. The elasticities from the residential and commercial econometric models are used to adjust downward the use-per-account forecast. Yet these elasticities appear to have been calculated from data that includes all historical natural gas consumption, without normalizing for changes in the number of accounts. If this is true, the elasticities were estimated from all five components of the response to a price change, but are then assumed to represent sound estimates for only the aggregation of Responses (iii), (iv) and (v).

This inconsistency appears to have occurred, based on the information provided by BC Gas; but it could be that the Commission has misunderstood the BC Gas methodology because of incomplete information. If this inconsistency has occurred, it could be resolved by assembling time series data of use-per-account and using these to estimate a use-per-account price elasticity that is separate from the forecast of the number of accounts, effectively disaggregating the estimation and forecasting of Responses (i) and (ii) from Responses (iii), (iv) and (v).

The second challenge to the BC Gas methodology is not as easy to correct. Under cross-examination, Mr. Gillies of BC Gas agreed that electricity is currently the major alternative to natural gas in the residential and commercial sectors (T8: 898). This holds for price Responses (i), (ii) and (iii) (however negligible (ii) is likely to be). Unfortunately, the electricity variable was not found to be statistically significant and was therefore omitted from the model, both for the total energy demand specification and for the relative energy shares specification. This occurred in both the residential and commercial sector models (T8: 901, T9: 1016-1022).

A fundamental problem arises from the exclusion of electricity. This exclusion may bias the estimated values of the other explanatory variables as well as increasing their statistical significance. Mr. Gillies was asked to report the results when electricity is included (T9: 1021-1022); the response was received in the June 24, 1994 letter from BC Gas. As expected, the inclusion of electricity changed the coefficients for other variables. In the residential model, the natural gas versus oil price ratio, which appears to be the most important coefficient for the elasticity determination with BC Gas's chosen specification, falls from a value of -.046 to -.013, a decrease of over 70 percent.

The exclusion of electricity seems justified in terms of the standard social science approach to empirical analysis. Econometricians seek to avoid committing a Type I Error, the error of incorrectly concluding that a variable is significant. To this end, they use stringent statistical criteria; in a statistical sense they will omit a variable if they cannot say that they are sure the variable will be found significant in 19 out of 20 tries. Electricity failed this test and was omitted (T9: 1022-1024).

However, the greater the emphasis on avoiding a Type I Error, the greater the chance of committing a Type II Error, that is, incorrectly concluding that a variable is not significant. Statistical power is a measure that assesses the likelihood of Type II Error; high statistical power implies low risk of Type II Error (statistical power = 1 minus the probability of a Type II Error). BC Gas was asked to provide the statistical power of its analysis (T9: 1022-1023), and the Utility responded in its June 24, 1994 letter. Statistical power for the electricity variable was low, 31 percent for the commercial model. (Although BC Gas did not provide information regarding the residential model, it appears that statistical power will be lower for the electricity variable in the residential model.) This means that the BC Gas specification had a 69 percent chance of committing a Type II Error, that is, of incorrectly omitting the electricity variable in the commercial model. This is a serious concern, given the BC Gas admission that electricity is an important determinant in the aggregate consumer response to a change in the price of natural gas.

3.3 Commission Determination

The Commission's decision on the RSAM proposal reduces the contentiousness surrounding short-term demand forecasting. Inaccurate forecasts will no longer result in a significant win-lose trade-off between customers and shareholders. However, sound forecasting is still desirable in order to minimize the risks of significant RSAM account balances that will in turn increase year-to-year rate variability.

BC Gas forecasts short-term natural gas demand based on a forecast of total accounts and a forecast of use-per-account. This latter is corrected for weather, technological trends, efficiency standards and other relevant factors. Ideally, one of the factors would be price, especially during times of significant price change for natural gas or a competing energy form.

However, based on the evidence in this hearing, the Commission cannot at this time accept as sound the price elasticity estimates used to adjust the use-per-account forecast of BC Gas. For the two year forecast period covered by this application, BC Gas shall use the use-per-account forecasts without adjustment for price effects.

In future applications, BC Gas may wish to again attempt to estimate the short-term effect of price changes on natural gas demand. However, the econometric expertise at BC Gas may be more prudently applied if such analysis were to focus at the use-per-account and end-use level. It is the Commission's understanding that this is an area of

greatly expanded interest in the application of econometrics to natural gas, one that can support the important research objective of better detecting the effect of demand-side management programs on natural gas consumption.

4.0 ACCOUNTING ISSUES

During the workshops and the alternative dispute resolution process preceding the Phase 1 hearing, certain controversial accounting issues were identified. Due to the highly technical nature of these issues, the Commission approved the proposal of BC Gas that they be dealt with by way of a working committee which would report to the Commission on or before June 6, 1994, the commencement of the Phase 2 hearing.

Exhibit 35 containing the recommendations and guidelines of the working committee, and Exhibit 35A setting out BC Gas' agreement with the guidelines, were filed in the Phase 2 hearing. No intervenor raised any issue in the hearing regarding the report or the guidelines. This Commission panel is cognizant that these same guidelines were also agreed upon by other gas utilities which are under the Commission's jurisdiction, and have been approved separately by the Commission as a whole.

The Commission therefore does not consider a second approval is required, other than to confirm that the net of tax AFUDC rate is effective January 1, 1994, and to direct BC Gas to conduct a study on the Utility's overheads capitalized. In particular, the Commission is interested in the relative overhead capitalization methodologies related to out-sourced activities versus in-house executed projects. The Utility is directed to consult with Commission staff to establish a suitable reporting format, and file a report with the Commission before September 30, 1995 as part of the 1996 revenue requirements application.

DATED at the City of Vancouver, in the Province of British Columbia this 4th day of August, 1994.

Dr. M.K. Jaccard
Chairperson

F.C. Leighton
Commissioner

BRITISH COLUMBIA
UTILITIES COMMISSION

ORDER
NUMBER G-59-94

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AN ORDER IN THE MATTER OF the Utilities Commission
Act, S.B.C. 1980, c. 60, as amended

and

An Application by BC Gas Utility Ltd.
Phase 2 - Revenue Stabilization Adjustment Mechanism and Sales Forecasts

BEFORE: M.K. Jaccard, Chairperson; and)
F.C. Leighton, Commissioner) August 4, 1994

O R D E R

WHEREAS:

A. On November 22, 1993 BC Gas Utility Ltd. ("BC Gas") filed with the Commission an application based on a two-year test period to increase, on an interim and permanent basis, captive rates of customers in the Lower Mainland, Inland and Columbia Divisions effective January 1, 1994 and a further increase effective January 1, 1995 ("the Application") pursuant to Sections 64, 67 and 106 of the Utilities Commission Act; and

B. The Commission, by Order No. G-120-93, approved for BC Gas an interim rate increase of 6.26 percent on gross margin revenue of the captive rate schedules effective with consumption on and after January 1, 1994; and

C. The Commission, by Order No. G-10-94, set the date of April 25, 1994 for the commencement of a public hearing into the Application and published dates for workshops, conferences and meetings in order to expedite the public review of the Application and attain a complete or partial negotiated settlement of the issues in the Application; and

D. The Commission, by Order No. G-26-94, rescheduled the commencement of the public hearing into the Application to May 2, 1994 and, by Order No. G-29-94, rescheduled the Integrated Resource Plan ("IRP") segment to June 6, 1994; and

E. A Negotiated Settlement process was used prior to the commencement of the public hearing into the Application; and

F. At the commencement of the hearing into the IRP segment, the Commission separated that hearing into two phases; and

G. Subsequently, during the hearing, the issues were further separated, such that IRP and Demand-Side Management would be heard separately from the proposal for a Revenue Stabilization Adjustment Mechanism ("RSAM") and the sales forecasts contained in the Application.

H. The Commission has determined that separate decisions into the BC Gas Application will be issued as follows:

Phase 1 Decision - 1994/95 Revenue Requirements issues dealt with in the May 2, 1994 hearing;
Phase 2 Decision - Revenue Stabilization Adjustment Mechanism and Sales Forecasts;
Phase 3 Decision - IRP and Demand-Side Management; and

. . . /2

I. The Commission has considered the Application and the evidence adduced thereto all as set forth in the Phase 2 Decision issued concurrently with this Order.

NOW THEREFORE the Commission, for reasons stated in the Phase 2 Decision, orders BC Gas as follows:

1. RSAM deferral accounts will be established, and the RSAM will be implemented with no deadband, as set out in the Phase 2 Decision.
2. BC Gas will comply with all directions contained in the Phase 2 Decision accompanying this Order.

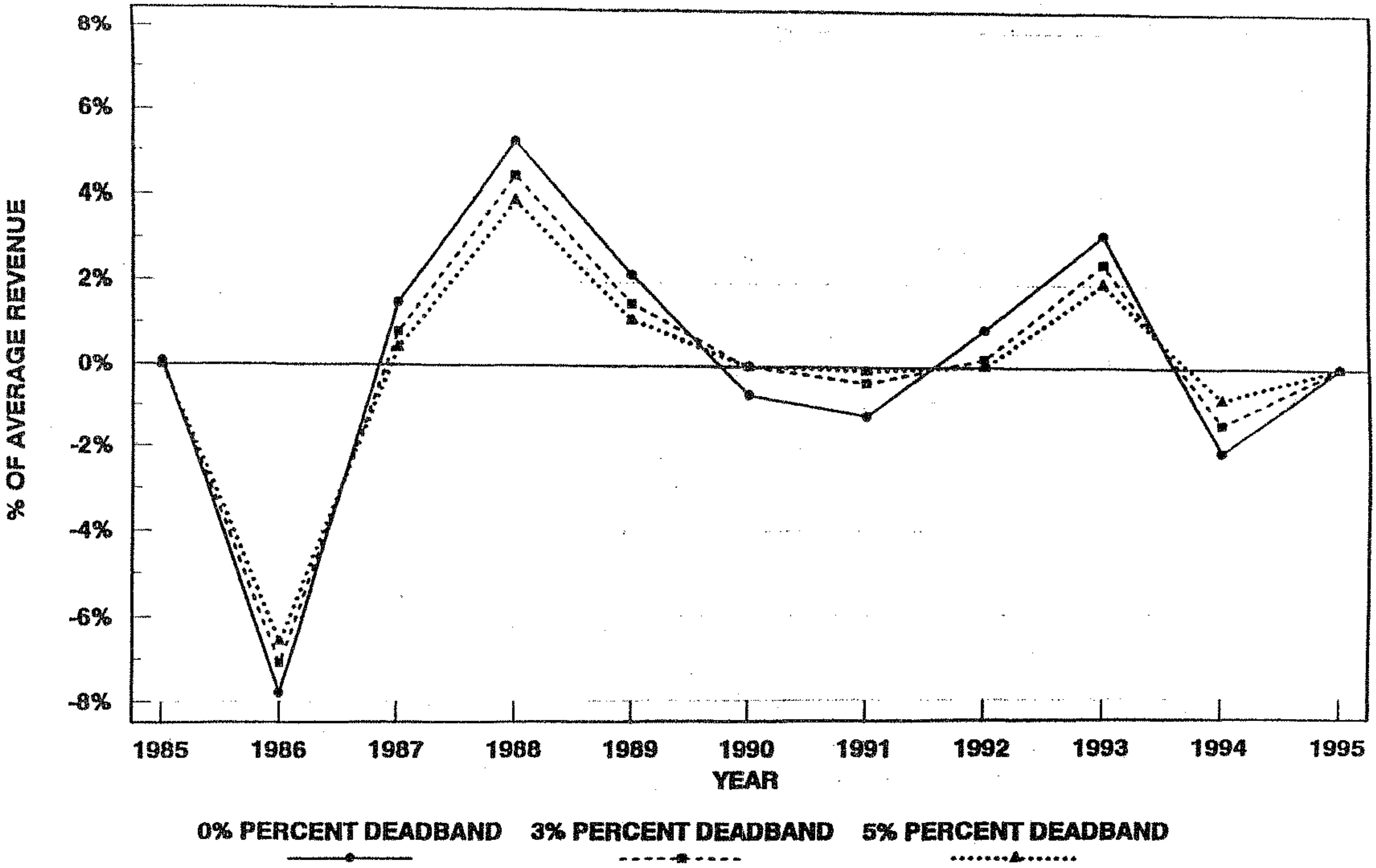
DATED at the City of Vancouver, in the Province of British Columbia, this 4th day of August 1994.

BY ORDER

Dr. Mark K. Jaccard
Chairperson

BC GAS UTILITY LTD.

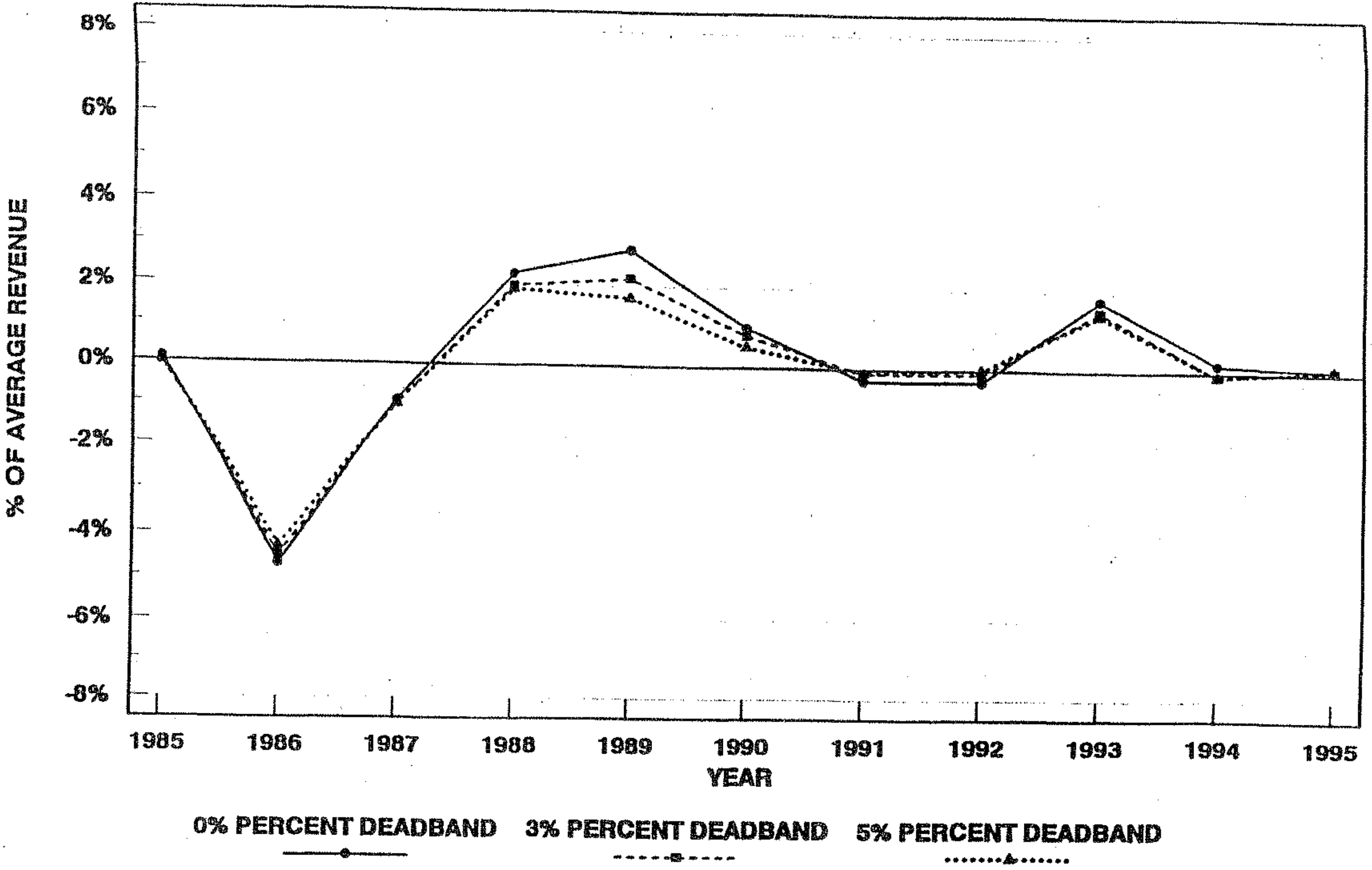
RSAM & GCRA - RESIDENTIAL RATE VARIABILITY
ONE YEAR RSAM AMORTIZATION



BCGas

BC GAS UTILITY LTD.

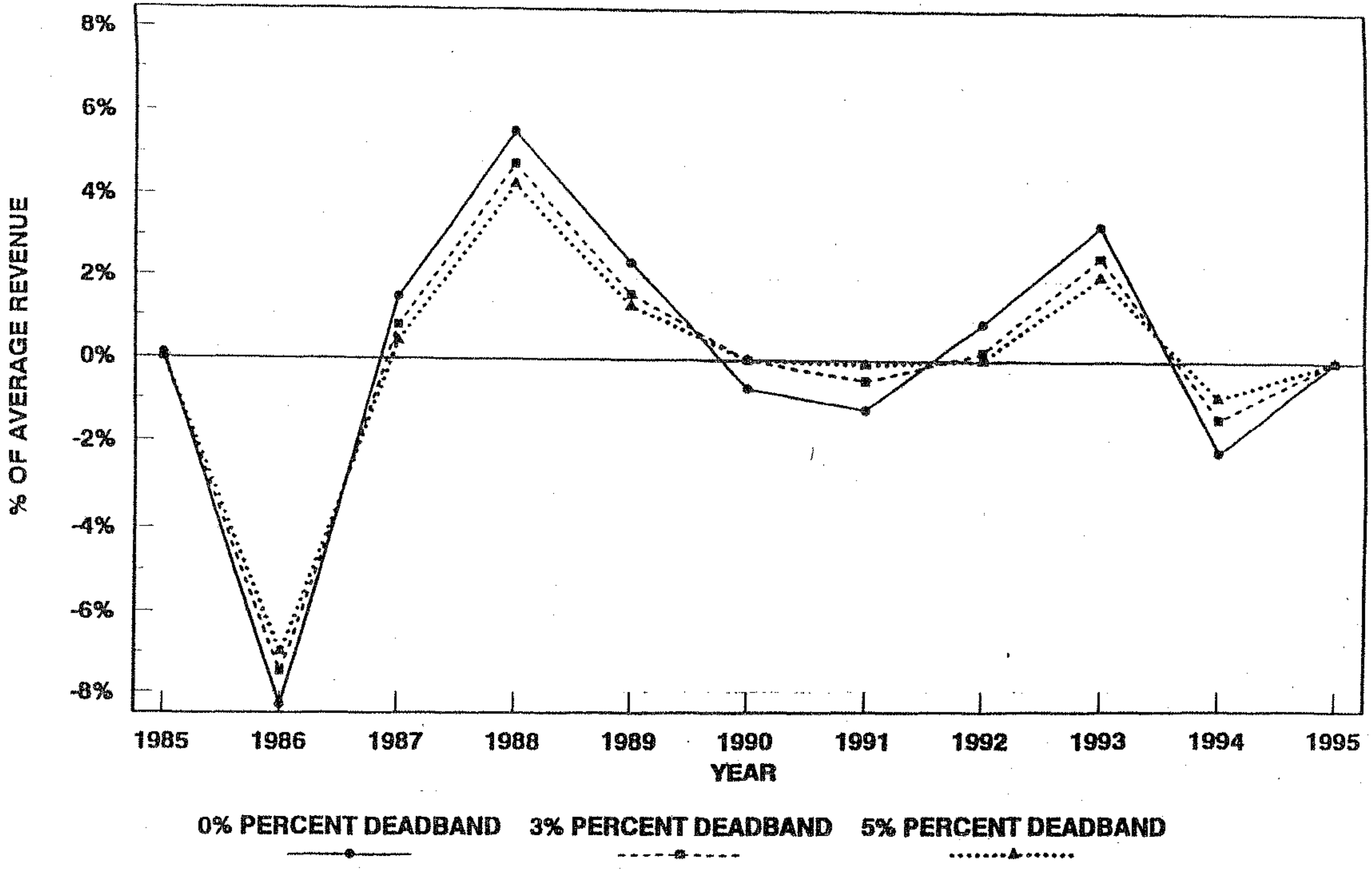
RSAM & GCRA - RESIDENTIAL RATE VARIABILITY
THREE YEAR RSAM AMORTIZATION



BCGas

BC GAS UTILITY LTD.

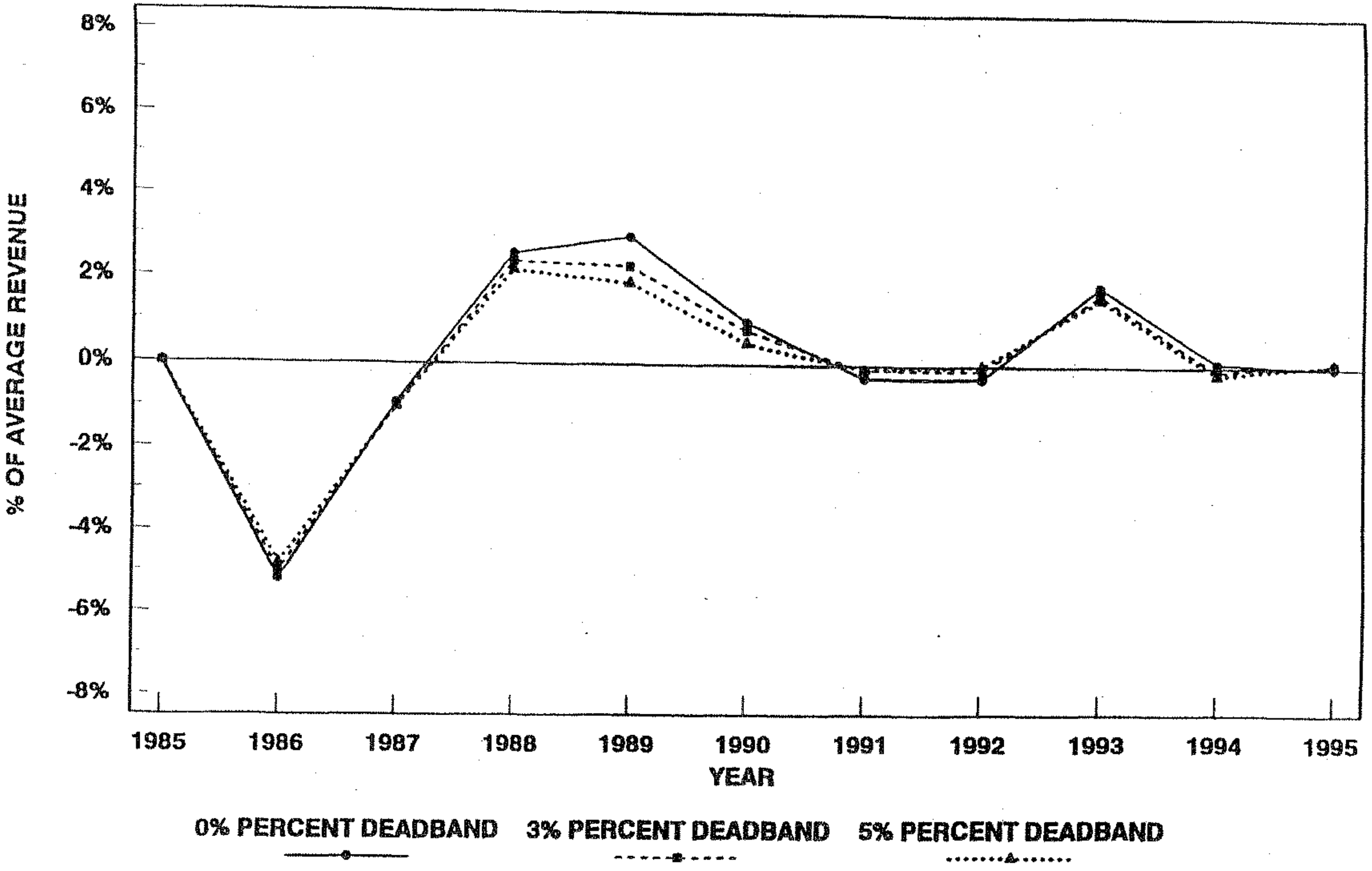
RSAM & GCRA - COMMERCIAL RATE VARIABILITY
ONE YEAR RSAM AMORTIZATION



BC Gas

BC GAS UTILITY LTD.

RSAM & GCRA - COMMERCIAL RATE VARIABILITY
THREE YEAR RSAM AMORTIZATION



APPENDIX B

APPEARANCES

G.A. FULTON	Commission Counsel
C.B. JOHNSON A.K. FUNG	Counsel for BC Gas Utility Ltd.
R.B. WALLACE	Weyerhaeuser Canada Ltd.; Cominco Ltd. and Celgar Pulp Company
MS. C. McCOOL	Consumers' Association of Canada (B.C. Branch); The British Columbia Old Age Pensioners' Organization; Council of Senior Citizens' Organization of B.C.; Federated Anti-Poverty Groups of B.C.; Senior Citizens' Association of B.C.; and West End Seniors' Network
D. RAWLYK	Energy Resources Management
R.T. O'CALLAGHAN	R.T. O'Callaghan & Associates, Inc.
P. KACIR	Crestbrook Forest Industries Ltd.; Consumers' Packaging; Elkview Coal Corporation; Hiram Walker & Sons Ltd.; and Fording Coal Ltd.
J.G. SMITH	The Agriculture Committee of the Chilliwack Chamber of Commerce
H. LEDDERHOF	Ecology Circle
MS. P.E. SCHMID	William Storage Company
MS. C. REARDON	Westcoast Environmental Law Society

W.J. GRANT P.H. GRONERT D.W. EMES J.W. FRASER S.S. WONG P.W. NAKONESHNY	Commission Staff
ALLWEST COURT REPORTERS LTD.	Court Reporters & Hearing Officer

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Letter dated June 8, 1994 from Department of Energy Washington, D.C. addressed to BC Gas Filing Clerk Public Utilities Commission of the State of California re: Docket R.94-04-031	57C
Document from Charles Rivers Associates entitled "Aligning Regulatory Incentives with IRP Policy Goals in the State of Illinois", dated June 1994	57D
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Filed: 2007-02-01
EB-2006-0034
Exhibit J2.1
Page 1 of 1

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

Filed: 2007-02-01
EB-2006-0034
Exhibit J2.2

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

UNDERTAKING J3.1

UNDERTAKING

Tr: 22

Provide data in Exhibit K2.6 on a calendar-year basis.

RESPONSE

In the 2005 rate case, the Company agreed to implement the four year phase-in amount for upstream transportation costs in October for each of the years from 2004 to 2007. The Company has since operated on a calendar year basis and as such, the information filed in Exhibits G and H reflect calendar year forecasts. Exhibit K2.6 was produced to reflect a calendar year forecast of revenues and costs but did not lay out that the phase-in amounts and associated impacts were being implemented as per the RP-2003-0203 Settlement Agreement in each rate case starting in October of the previous year.

Exhibit K2.6 has been reproduced here as requested in the undertaking, to illustrate that the recovery of the phase-in amounts actually begins in October of the previous year, and to show associated over/under contribution and revenue to cost ratios. This Exhibit excludes the years from 2001 to 2004 because there was no phase-in amount under the previous cost allocation methodology. In order to provide the information in Exhibit K2.6 on this basis, it was assumed that 25% of the phase-in costs are recovered in the months of October to December from the previous year. This 25% for Rate 1 and 6 is representative of the proportion of volumes for October to December, relative to the entire year. This Exhibit illustrates that the phase-in will be fully completed on October 1, 2007. At that time, the over/under contribution embedded in rates will be $5,346 (thousand) for Rate 1 and $171 (thousand) for Rate 6. These amounts relate only to the recovery of the revenue requirement in F2007. The October 1, 2007 information has been provided based on a 12 month forecast assuming that all costs and revenues will be unchanged after December 31, 2007 to demonstrate that no more phase-in amounts will be recovered from Rate 1 and 6 after September 30, 2007. The total revenues, costs, over contribution and phase-in amounts for this analysis match in total with what was provided in Exhibit K2.6. This demonstrates that the October phase-in adjustment start date has only resulted in a timing difference relative to the way that information was provided in Exhibit K2.6.

Witnesses: J. Collier
A. Kacicnik

Note: in $ thousands except Revenue/Cost ratios.

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	Costs	Over Contribution	R/C	Phase-in Adjustment	Over Cont. Adjusted	R/C Adjusted
October 1, 2004	2,180	n/a	2,180	n/a	(2,180)	n/a	n/a
January 1, 2005	873,001	867,650	5,351	1.01	(7,893)	(2,542)	1.00
January 1, 2006	899,231	890,580	8,651	1.01	(5,306)	3,345	1.00
January 1, 2007	853,943	844,839	9,104	1.01	(3,758)	5,346	1.01
October 1, 2007	850,185	844,839	5,346	1.01	-	5,346	1.01

Notes:
October 1, 2004 reflects October 1 start date for recovery of calandar 2005 phase-in costs.
October 1, 2007 depicts a 12 month forecast of revenues and costs assuming phase-in is completed
Col 2 =Revenues excluding Commodity
Col 3 = 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 = 0.50 c/m3 for Rate 1 customers
Col 7 = Col 4 + Col 6
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
October 1, 2004	2,180	n/a	2,180	n/a	(2,180)	n/a	n/a
January 1, 2005	414,750	405,317	9,432	1.02	(7,837)	1,596	1.00
January 1, 2006	414,042	409,920	4,121	1.01	(5,109)	(987)	1.00
January 1, 2007	372,624	368,783	3,841	1.01	(3,669)	172	1.00
October 1, 2007	368,955	368,783	172	1.00	-	172	1.00

Notes:
October 1, 2004 reflects October 1 start date for recovery of calandar 2005 phase-in costs.
October 1, 2007 depicts a 12 month forecast of revenues and costs assuming phase-in is completed
Col 2 =Revenues excluding Commodity
Col 3 = 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 = 0.50 c/m3 for Rate 6 customers
Col 7 = Col 4 + Col 6
Col 8 = (Col 2+Col 6)/Col 3 for 2005-2007

Witnesses: J. Collier
A. Kacicnik

UNDERTAKING J3.2

UNDERTAKING

Tr: 65

File analysis of impact of moving Rate 1 to revenue-to-cost ratio of 1.0.

RESPONSE

As discussed at 3 Tr. 60, the Company has performed some analysis of the impact on other rates classes of moving the Rate 1 revenue to cost ratio to 1.0 in the 2007 Test Year. This analysis is based on the scenario where the Company recovers a revenue deficiency of $26.0 million. The following chart depicts the revenue to cost ratios, over/under contribution and rate impacts resulting from moving the Rate 1 revenue to cost ratio of 1.0 and assumes the Rate 1 and 6 rate classes continue to recover the phase in adjustment of TCPL tolls until September 30, 2007.

When the TCPL phase in amount is removed, the revenue to cost ratio for Rate 1 as shown in this chart is 1.0. When compared to the Company's proposal as filed at Exhibit N1, Tab 1, Schedule 1, Appendix B, page 1, the over contribution (excluding TCPL phase in) for Rate 1 has been transferred to the large volume rates. This results in a rate decrease for Rate 1, no change for Rate 6 and a rate increase for all other rate classes. The rate impacts that are included in the Company's proposal are reproduced in the final column of this chart.

Witnesses: J. Collier
A. Kacicnik

EGD 2007 ADR PROPOSAL
BASED ON REVENUE DEFICIENCY OF $26 MILLION
Rate 1 at 1.0 After Phase-In Allocation

	Impacts Relative to July 1, 2006 Rates						
Rate Class	Revenue to Cost Ratios 2007	Revenue to Cost Ratios 2006	Over/Under Contribution 2007	Over/Under Contribution 2006	TCPL Phase In Contribution	Average Rate Impact T-Service (1)	Average Rate Impact T-Service Per Company Proposal
			$/M	$/M	$/M		
1	1.01	1.01	5.01	8.75	5.01	1.43%	2.07%
6	1.01	1.01	5.07	4.19	4.89	0.66%	0.66%
9	0.69	0.69	-0.47	-0.59	0.00	6.44%	6.44%
100	0.99	0.98	-1.48	-2.92	0.00	3.56%	1.91%
110	1.02	1.01	0.88	0.33	0.00	0.51%	-0.85%
115	0.91	0.90	-3.98	-5.49	-5.97	1.49%	0.96%
135	0.87	0.87	-0.28	-0.33	-0.60	1.25%	1.25%
145	1.00	1.03	0.01	0.42	0.00	5.07%	1.62%
170	0.86	0.89	-3.65	-3.48	-3.20	8.04%	1.76%
200	0.98	0.98	-0.22	-0.20	0.00	4.60%	4.60%

Note: 2006 and 2007 Over/Under Contributions need to be adjusted by the TCPL phase in contribution amount to reflect the post October 1, 2007 situation.
(1) Impact includes the over/under contribution amounts

Witnesses: J. Collier
A. Kacicnik

Filed: 2007-02-16
EB-2006-0034
Exhibit J3.3

UNDERTAKING J3.3

UNDERTAKING

Tr: 82

To provide a breakout of $16.1 million as between updated weather methodology, declining average use, and loss of contract volumes.

RESPONSE

Please refer to Exhibit K4.1 for the breakdown of $16.1 million.

Witnesses: I. Chan
K. Culbert
T. Ladanyi

UNDERTAKING J3.4

UNDERTAKING

Tr: 86

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.

RESPONSE

Each Account Executive has an individual scorecard which is one of the tools used to measure individual performance and determine incentive compensation. One of the metrics on the Account Executive’s scorecard is the accuracy of their forecasting for each large volume contract customer for which they are responsible.

The Account Executive is not measured by whether they actually “beat” the forecast. Rather, they are measured on how accurate they are in establishing the forecast and then comparing that estimate to the customer’s actual usage.

Witnesses: J. Sarnovsky

Filed: 2007-02-16
EB-2006-0034
Exhibit J3.5

UNDERTAKING J3.5

UNDERTAKING

Tr: 97

Produce forecast price for 2007.

RESPONSE

Please see response to Undertaking J3.8.

Witnesses: I. Chan
J. Denomy
T. Ladanyi

UNDERTAKING J3.6

UNDERTAKING

Tr: 98

Update Table 1 at Exhibit I, Tab 2, Schedule 27, page 2.

RESPONSE

Table 1 below presents an updated Table 1 at Exhibit I, Tab 2, Schedule 27, page 2. As stated in the response to Exhibit I, Tab 2, Schedule 27, the test year volume budget represents the forecast that integrates all of the actual experience and the best known information at the time the budget was developed as in the past. Therefore, PIRA Energy Group (Items 1.7 and 1.8) was selected at that time as they contained the latest available information based upon the publication date. Between two different pricing alternatives, Henry Hub Spot pricing (Item 1.7) is used since its forecast can be easily compared to three other publishers for reasonability in terms of direction whereas NYMEX Futures gas price forecast is not available from the other publishers. Overall, all the natural gas price forecasts publications continue to predict that nominal gas prices will be even higher in 2007 than the historic high prices in 2006.

Table 1
Summary of Natural Gas Price Forecasts (Year over Year Percentage Change)

Item	Col. 1 Publisher	Col. 2 Date of Publication	Col. 3 2007/2006	Col. 6 Natural Gas Pricing
1.1	McDaniel Associates	January 1, 2007	9.6%	Henry Hub Spot
1.2	McDaniel Associates	January 1, 2007	9.6%	Alberta AECO
1.3	AJM Petroleum Consultants	December 31, 2006	12.8%	Alberta AECO
1.4	AJM Petroleum Consultants	December 31, 2006	14.2%	NYMEX US$/MCF Current
1.5	Fekete Associates Inc.	October 16, 2006	20.3%	Henry Hub Spot
1.6	Fekete Associates Inc.	October 16, 2006	25.8%	AECO-C Hub
1.7	PIRA Energy Group	January 26, 2007	14.4%	Henry Hub Spot
1.8	PIRA Energy Group	January 26, 2007	12.3%	NYMEX Futures
1.9	Sproule	December 31, 2006	8.6%	Henry Hub Spot
1.10	Sproule	December 31, 2006	7.8%	Alberta AECO - C Spot

Witnesses: I. Chan
J. Denomy
T. Ladanyi

UNDERTAKING J3.7

UNDERTAKING

Tr: 113

To advise the impact of a one percent change in the price of general service volumes.

RESPONSE

Impact of a one percent change in the real natural gas price of general service volumes is equal to a change in total general service volumes of approximately 6.1 10^6m^3, holding other things constant.

Similarly, a ten percent change in the real natural gas price of general service volumes is equal to a change in total general service volumes of approximately 61.0 10^6m^3, holding other things constant. It should be noted that general service volumetric changes associated with changing the price can vary each year as a result of changes to customer mix and actual price elasticities between different customer groups. Therefore, the impact provided here is only relevant to the 2007 Test Year volume budget.

Witnesses: I. Chan
J. Denomy
T. Ladanyi

UNDERTAKING J3.8

UNDERTAKING

Tr: 115

To provide a price per m^3 that corresponds to the 8.5 percent under the 2007.

RESPONSE

The price per m^3 that corresponds to the 8.5% in 2007 on Table 2 of Exhibit C2, Tab 3, Schedule 1 is $0.46/m^3. This real gas price is a burner tip price and thus includes the monthly customer charge, delivery charge and commodity charge.

Witnesses: I. Chan
J. Denomy
T. Ladanyi

UNDERTAKING J3.9

UNDERTAKING

Tr: 118

Add three columns to Table 4: actual throughput volumes; weather normalized throughput volumes; board-approved throughput volumes.

RESPONSE

Please see Table 1 on the next page for the addition of three columns to Table 4 of Exhibit C2, Tab 4, Schedule 1.

Overall, the de Bever weather normalization methodology has resulted in:
- a cumulative overforecast of 2,098 degree days
- or 2 778 10^6m^3 in throughput volumes
- or an average annual overforecast of 161 degree days
- or 214 10^6m^3 in throughput volumes

over the thirteen years during 1990-2002.

As stated in the volume evidence at Exhibit C3, Tab 1, Schedule 1, weather or degree days is not the only driver variable that accounts for each year's actual un-normalized volumetric variances. There are other driver variables that impact each year's actual un-normalized volumetric variances, such as customer growth, the Company's Demand Side Management ("DSM") Initiatives, and contract market volumes.

Witnesses: I. Chan
J. Denomy
T. Ladanyi

Actual versus Board Approved Gas Supply degree days and Volumes

Col. 1 Year	Col. 2 Actual	Col. 3 Board Approved	Col. 4 =Col. 3-2 Variance	Col. 5 Actual Volume (10^6m^3)	Col. 6 Normalized Actual Volume (10^6m^3)	Col. 7 Board Approved Volume (10^6m^3)	Col. 8 =Col. 6-5 Weather Impact (10^6m^3)
1990	3,918	3,968	50	9,995	9,968	10,184	(27)
1991	3,574	3,957	383	9,292	9,863	10,148	572
1992	3,939	3,958	19	10,201	10,279	10,275	78
1993	4,042	3,874	(168)	10,517	10,446	10,419	(71)
1994	4,275	3,910	(365)	11,118	10,588	10,541	(530)
1995	3,747	3,955	208	10,390	10,810	10,598	420
1996	4,209	4,058	(151)	11,506	11,058	10,928	(448)
1997	4,011	4,003	(8)	11,527	11,438	11,109	(90)
1998	3,352	4,079	727	10,714	11,777	11,720	1,063
1999	3,460	4,060	600	10,992	11,844	12,165	852
2000	3,569	3,929	360	11,569	12,162	11,995	594
2001	3,743	3,808	65	11,738	11,591	11,847	(147)
2002	3,322	3,700	378	11,275	11,787	11,776	512

Cumulative Overforecast 2,098 Degree Days 2,778 10^6m^3
Average Annual Overforecast 161 Degree Days 214 10^6m^3

Note:
2003 to 2006 Degree Days were not de Bever numbers as they were negotiated numbers in the Settlement Agreement for these test years.

Witnesses: I. Chan
J. Denomy
T. Ladanyi

UNDERTAKING J3.10

UNDERTAKING

Tr: 126

To provide adjusted r-square values for models described in Table 6 of Exhibit C2, Tab 4, Schedule 1.

RESPONSE

The table below shows the adjusted R-squared values for the regression models for the Central weather zone described in Table 6 of Exhibit C2, Tab 4, Schedule 1.

For example, the adjusted R-squared value of 0.174 for 1990 for the 20-Year Trend method is the adjusted R-squared of the 20-Year Trend model used to produce the forecast of environment Canada degree days for 1990. This particular 20-Year Trend model would have been estimated using data from 1969 to 1988.

Note that all models exhibit a low adjusted R-squared that varies over time. It is important to note that the adjusted R-squared value for a regression equation is not entirely indicative of the forecasting ability of a regression model. It is important to examine not only regression diagnostic statistics but also a model's forecasting ability.

While all the degree day regression models examined have low adjusted R-squared values, the 20-Year trend method ranks best in terms of forecasting ability when compared to all competing models as shown in Exhibit C2, Tab 4, Schedule 1, Table 6.

Witnesses: I. Chan
J. Denomy
T. Ladanyi

Adjusted R-Squared Values for Various Degree Day Forecasting Methods Central Weather Zone

Fiscal Year	20-Year Trend	de Bever	de Bever with Trend	Energy Probe
1990	0.174	0.187	0.172	0.178
1991	0.222	0.186	0.171	0.175
1992	0.201	0.196	0.184	0.189
1993	0.282	0.194	0.246	0.224
1994	0.246	0.177	0.240	0.218
1995	0.220	0.181	0.202	0.186
1996	0.104	0.134	0.124	0.112
1997	0.213	0.122	0.138	0.114
1998	0.156	0.102	0.127	0.124
1999	0.080	0.109	0.130	0.130
2000	0.113	0.072	0.168	0.161
2001	0.156	0.063	0.240	0.240
2002	0.210	0.104	0.334	0.337
2003	0.175	0.150	0.357	0.362
2004	0.189	0.243	0.396	0.416
2005	0.155	0.194	0.373	0.404

For completeness the following two tables show the adjusted R-squared values for the regression models for the Eastern and Niagara weather zones. These tables correspond to the models used to calculate Table 6 Eastern and Table 6 Niagara provided in response to Energy Probe Interrogatory #8 at Exhibit I, Tab 5, Schedule 8.

Adjusted R-Squared Values for Various Degree Day Forecasting Methods Eastern Weather Zone

Fiscal Year	20-Year Trend	de Bever	de Bever with Trend	Energy Probe
1990	0.294	0.017	0.075	0.051
1991	0.276	0.001	0.053	0.024
1992	0.163	0.063	0.062	0.036
1993	0.209	0.084	0.124	0.096
1994	0.044	0.058	0.122	0.128
1995	0.011	0.052	0.070	0.072
1996	-0.053	0.018	0.019	0.032
1997	0.013	0.019	0.074	0.068
1998	-0.030	0.021	0.075	0.080
1999	-0.052	0.045	0.038	0.024
2000	-0.038	0.023	0.131	0.185
2001	0.000	0.011	0.186	0.261
2002	0.051	0.038	0.235	0.299
2003	0.015	0.046	0.243	0.304
2004	0.044	0.137	0.295	0.372
2005	0.017	0.092	0.188	0.297

Witnesses: I. Chan
J. Denomy
T. Ladanyi

Adjusted R-Squared Values for Various Degree Day Forecasting Methods Niagara Weather Zone

Fiscal Year	20-Year Trend	de Bever	de Bever with Trend	Energy Probe
1990	-0.044	0.032	0.018	0.152
1991	-0.031	0.028	0.009	0.128
1992	-0.028	0.032	0.009	0.125
1993	0.055	0.024	0.010	0.017
1994	0.050	0.008	0.004	0.005
1995	0.037	-0.022	-0.038	-0.036
1996	-0.024	-0.018	-0.045	-0.009
1997	0.035	-0.027	-0.053	-0.055
1998	0.033	-0.027	-0.054	0.008
1999	-0.008	-0.025	-0.053	-0.013
2000	0.011	-0.026	-0.028	0.017
2001	0.040	-0.024	0.009	0.089
2002	0.085	-0.028	0.049	0.148
2003	0.036	-0.027	0.034	0.130
2004	0.041	0.012	0.122	0.237
2005	0.006	-0.015	0.061	0.235

UNDERTAKING J4.1

UNDERTAKING

Tr: 29

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.

RESPONSE

Confirmed. The current rates in place were approved by the Board in the EB-2005-0001 Decision and are based on 3,745 degree days for the 2006 Test Year for the Central Region. The 3,745 degree day number was arrived through negotiation and is not based on any particular methodology.

In the EB-2006-0034 rate case, the Company has applied for approval of the 20-year Trend methodology for forecasting degree days. The application of the 20-year trend to the degree day data produces a forecast of 3,617 degree days for 2007. Compared to the revenue forecast at current rates which were based on 3,745 degree days, the forecast using the 20-year trend methodology results in a reduction in the revenue forecast which, when applied to the 2007 Test Year revenue requirement, results in a revenue deficiency of $12.9 million.

The application of the de Bever methodology to the degree day data produces a degree day forecast of 3,793 degree days for 2007. Compared to the revenue forecast at current rates which were based on 3,745 degree days, the forecast using the de Bever methodology results in an increase in the revenue forecast which, when applied to the to the 2007 Test Year revenue requirement, results in a revenue sufficiency of $8.3 million.

The change from the $12.9 million deficiency based on the 20-year trend methodology to the $8.3 million sufficiency based on the de Bever methodology is $21.2 million, holding other things constant. It should, however, be noted that these impacts on the deficiency only deal with changes in degree days. The overall volume deficiency is also affected by the decline in average use due to conservation, the loss of industrial load partially offset by customer growth.

Witnesses: I. Chan
J. Denomy
T. Ladanyi

UNDERTAKING J4.2

UNDERTAKING

Tr: 30

Portion, in dollars, of the $21.2 million impact between existing and proposed methodology that is Rate 1 and proportion that is Rate 6.

RESPONSE

Of the $21.2 million impact between the de Bever and the proposed 20 year trend methodology, Rate 1 and Rate 6 amount to approximately $13.1 million and $6.7 million, respectively.

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

UNDERTAKING J4.3

UNDERTAKING

Tr: 82

Produce the trend line on actual data from 1965 to 2007 for all three regions.

RESPONSE

Figures 1 through 3 show the trend lines on the actual data found on Figures 4 through 6 in Exhibit C2, Tab 4, Schedule 1. The trend lines on actual data are constructed using data from 1965-2005 for each weather zone. For comparison purposes the 20-Year Trend line is presented in Figures 1 through 3 as well. The 20-Year Trend lines are constructed using data from 1986-2005 for each weather zone and are the same trend lines shown in Tables 4 through 6 of Exhibit C2, Tab 4, Schedule 1.

Figure 4 shows the actual degree day data and the 1965-2005 trend lines presented in Figures 1 through 3 for all three weather zones. In all cases there is a downward trend in degree days for all three weather zones.

Witnesses: I. Chan
J. Denomy
T. Ladanyi

Figure 1 Actual, fitted and forecast Environment Canada degree days, Central

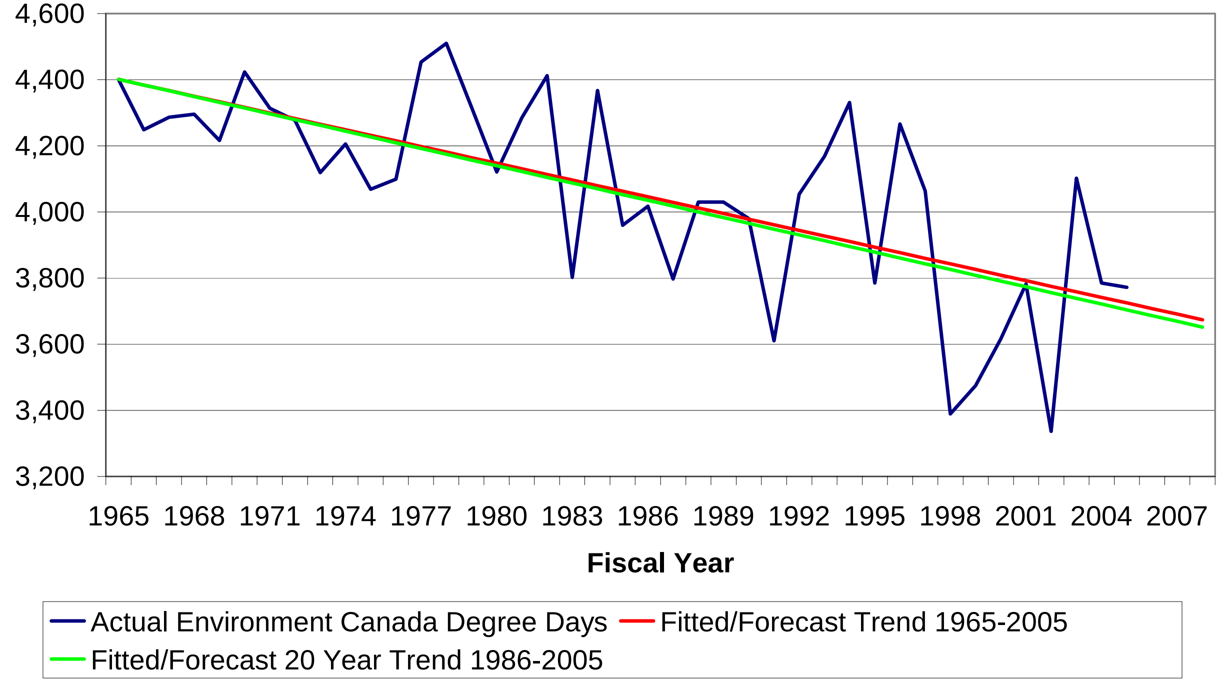
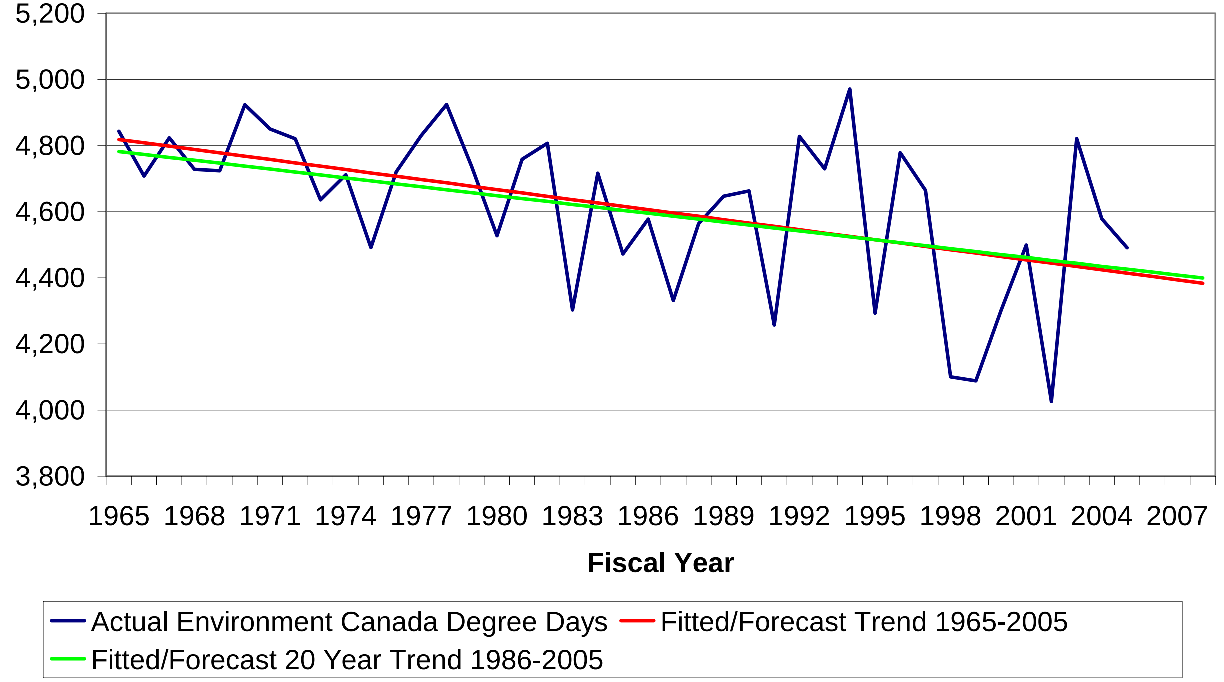


Figure 2 Actual, fitted and forecast Environment Canada degree days, Eastern



Witnesses: I. Chan
J. Denomy
T. Ladanyi

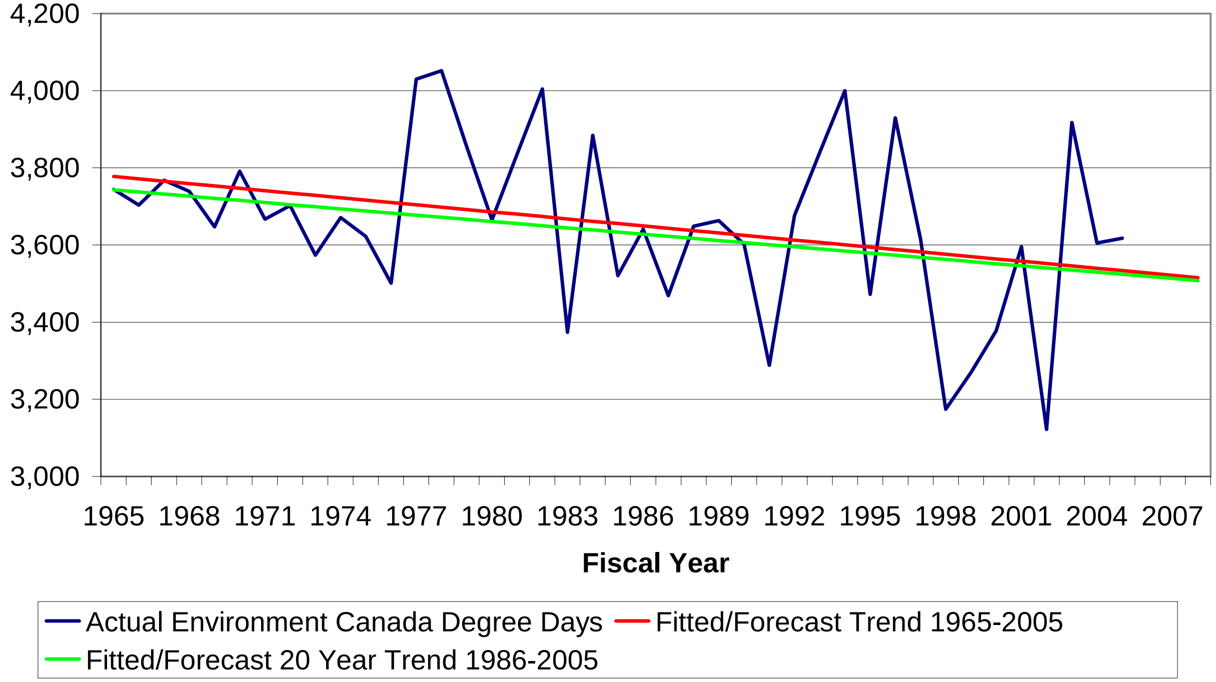
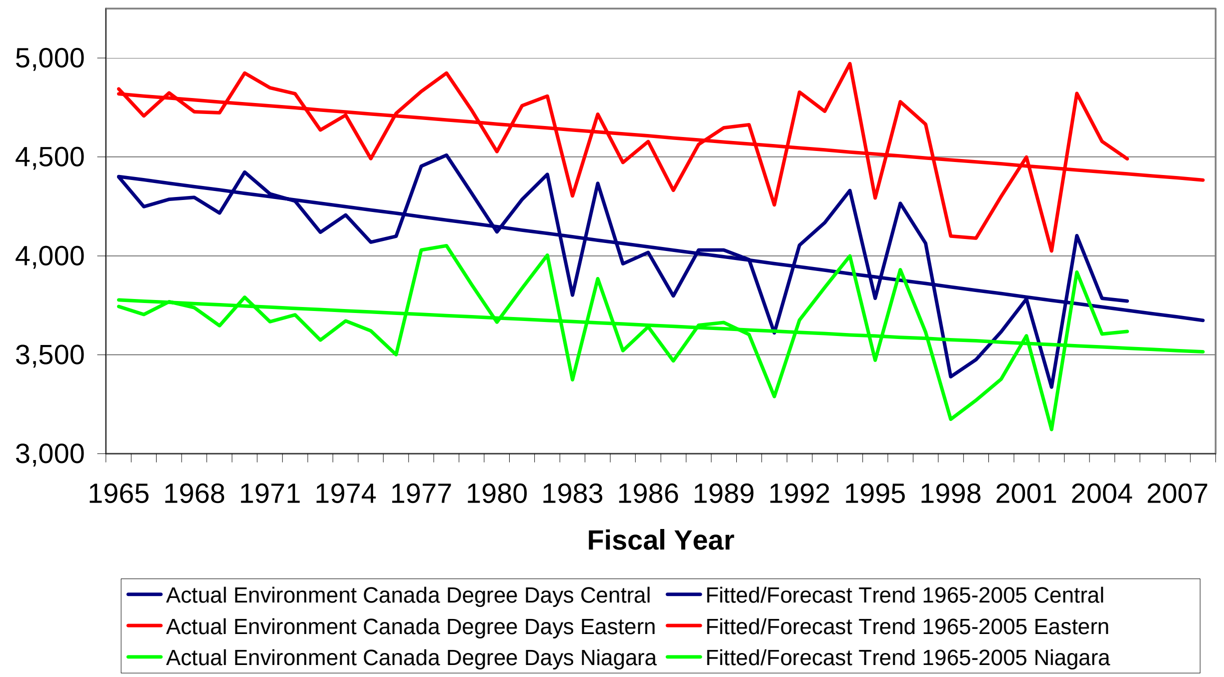


Figure 3 Actual, fitted and forecast Environment Canada degree days, Niagara

Witnesses: I. Chan
J. Denomy
T. Ladanyi

Figure 4 Actual, fitted and forecast Environment Canada degree days using trend from 1965-2005, All Weather Zones



UNDERTAKING J4.4

UNDERTAKING

Tr: 92

Provide a version of K4.5, excluding the de bever, de bever with trend and energy probe methods, starting from the year 1976.

RESPONSE

Please see the table below for a version of K4.5 which excludes the de Bever, de Bever with trend and Energy Probe methods. The calculations in the table contain data from 1976 up to and including 2005. The “Averages 1976-2005” portion of the table contains simple averages of the data for each of the three weather zones. The “Weighted Average 1976-2005” portion of the table contains a volumetrically weighted average of all three weather zones. The weights are as follows: Central 80%, Eastern 12%, Niagara 8%. The weighted averages are more appropriate given that the majority of the Company’s volumes are delivered in the Central weather zone.

Witnesses: I. Chan
J. Denomy
T. Ladanyi

Exhibit K4.5 Excluding de Bever, de Bever with Trend and Energy Probe Methods 1976-2005

Toronto Region (1976-2005)	**Actual**	**Naïve**	**10-yr MA**	**20-yr MA**	**20-yr Trend**	**30-yr MA**	**50/50**
Item							
Total Degree Days	119,712	120,430	122,913	124,093	121,112	123,990	122,551
Overforecast		16	19	20	16	18	19
Underforecast		14	11	10	14	12	11
Variance From Actual		718	3,201	4,381	1,400	4,278	2,839
Percentage Variance		0.60%	2.67%	3.66%	1.17%	3.57%	2.37%
Eastern Region (1976-2005)							
Item							
Total Degree Days	137,005	137,138	138,884	139,766	137,483	139,987	138,735
Overforecast		14	16	17	14	17	14
Underforecast		16	14	13	16	13	16
Variance From Actual		134	1,880	2,762	479	2,982	1,731
Percentage Variance		0.10%	1.37%	2.02%	0.35%	2.18%	1.26%
Niagara Region (1976-2005)							
Item							
Total Degree Days	109,241	109,312	110,207	110,609	109,431	110,338	109,884
Overforecast		16	16	18	15	19	16
Underforecast		14	14	12	15	11	14
Variance From Actual		70	966	1,368	189	1,096	643
Percentage Variance		0.06%	0.88%	1.25%	0.17%	1.00%	0.59%
Averages (1976-2005)							
Item							
Total Degree Days	121,986	122,293	124,001	124,823	122,675	124,772	123,723
Overforecast		51%	57%	61%	50%	60%	54%
Underforecast		49%	43%	39%	50%	40%	46%
Variance From Actual		307	2,015	2,837	689	2,786	1,738
Percentage Variance		0.25%	1.65%	2.33%	0.57%	2.28%	1.42%
Weighted Averages (1976-2005)							
Item							
Total Degree Days	120,949	121,546	123,813	124,895	122,142	124,818	123,480
Overforecast		53%	61%	65%	52%	60%	61%
Underforecast		47%	39%	35%	48%	40%	39%
Variance From Actual		596	2,863	3,946	1,193	3,868	2,530
Percentage Variance		0.49%	2.37%	3.26%	0.99%	3.20%	2.09%

Witnesses: I. Chan
J. Denomy
T. Ladanyi

UNDERTAKING J4.5

UNDERTAKING

Tr: 103

Provide 20-year data set that tracks variations from actual to board-approved each year for degree days and for ROE.

RESPONSE

The table below shows Actual to Board Approved degree days and Actual ROE to Board Approved ROE for the 21 year period 1985 to 2005.

Year	Actual Gas Supply Degree Days Central Region[a]	Board Approved Degree Days[a]	Variance	Percentage Variance	Actual ROE[b]	Board Approved ROE[b]	Variance
1985	3,873	4,074	-201	-4.93%	14.580%	15.300%	-0.720%
1986	3,950	4,122	-172	-4.17%	14.690%	15.000%	-0.310%
1987	3,707	4,058	-351	-8.65%	12.260%	14.000%	-1.740%
1988	3,947	3,989	-42	-1.05%	15.460%	14.000%	1.460%
1989	3,983	4,105	-122	-2.97%	15.540%	13.500%	2.040%
1990	3,918	3,968	-50	-1.26%	13.570%	13.250%	0.320%
1991	3,574	3,957	-383	-9.68%	9.400%	13.125%	-3.725%
1992	3,939	3,958	-19	-0.48%	13.290%	13.125%	0.165%
1993	4,042	3,874	168	4.34%	15.260%	12.300%	2.960%
1994	4,275	3,910	365	9.34%	14.690%	11.600%	3.090%
1995	3,747	3,955	-208	-5.26%	10.710%	11.650%	-0.940%
1996	4,209	4,058	151	3.72%	15.000%	11.875%	3.125%
1997	4,011	4,003	8	0.20%	13.170%	11.500%	1.670%
1998	3,352	4,079	-727	-17.82%	8.310%	10.300%	-1.990%
1999	3,460	4,060	-600	-14.78%	7.943%	9.510%	-1.567%
2000	3,569	3,929	-360	-9.16%	8.229%	9.730%	-1.501%
2001	3,743	3,808	-65	-1.71%	10.800%	9.540%	1.260%
2002	3,322	3,700	-378	-10.22%	8.982%	9.660%	-0.678%
2003	4,058	3,565	493	13.83%	13.140%	9.690%	3.450%
2004[c]	3,754	3,565	189	5.30%	12.165%	9.690%	2.475%
2005	3,719	3,747	-28	-0.75%	9.457%	9.570%	-0.113%

[a] From Exhibit C2, Tab 4, Schedule 1, Page 5
[b] From VECC Interrogatory at Exhibit I, Tab 24, Schedule 45, Page 2
[c] Due to the nature of the 2004 rates application there is no Board approved degree day forecast or ROE for the 2004 test year.

Witnesses: I. Chan
J. Denomy
T. Ladanyi

UNDERTAKING J4.6

UNDERTAKING

Tr: 105

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.

RESPONSE

The table below shows the forecast of Environment Canada degree days for the Central Weather zone using a six year trend model estimated over the consecutive six-year periods shown in Exhibit C2, Tab 4, Schedule 1, Table 13. In order to produce a six year forecast from 2007 to 2012, actual degree day data for 2006 have been included as well.

The table can be read as follows:

Column 1 – Fiscal Year.

Column 2 – Actual Environment Canada degree days.

Column 3 – Data from 1970 to 1975 are the actual data used to estimate a six year trend model for that period. Shaded data from 1976 to 1981 are the forecast of degree days produced by the six year trend model estimated using the actual data from 1970 to 1975.

Columns 4 to 34 – Show the same analysis as in Column 3 with the six-year period shifted up by one year.

It can be easily seen that the degree day forecasts from the 6-year trend method are highly unstable and extremely inaccurate. Consequently the Company is of the opinion that this method should not be considered as a degree day forecasting method. The inaccurate and unstable results shown below would subject both ratepayers and the Company to an undue amount of rate instability and weather forecasting risk.

Witnesses: I. Chan
J. Denomy
T. Ladanyi

Witnesses: I. Chan
J. Denomy
T. Ladanyi

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	Col. 17
Fiscal Year	ECCDD	ECCDD81	ECCDD82	ECCDD83	ECCDD84	ECCDD85	ECCDD86	ECCDD87	ECCDD88	ECCDD89	ECCDD90	ECCDD91	ECCDD92	ECCDD93	ECCDD94	ECCDD95
1970	4,423	4,423														
1971	4,314	4,314	4,314													
1972	4,277	4,277	4,277	4,277												
1973	4,119	4,119	4,119	4,119	4,119											
1974	4,206	4,206	4,206	4,206	4,206	4,206										
1975	4,069	4,069	4,069	4,069	4,069	4,069	4,069									
1976	4,099	4,009	4,099	4,099	4,099	4,099	4,099	4,099								
1977	4,453	3,945	4,019	4,453	4,453	4,453	4,453	4,453	4,453							
1978	4,510	3,880	3,973	4,272	4,510	4,510	4,510	4,510	4,510	4,510						
1979	4,317	3,816	3,927	4,292	4,515	4,317	4,317	4,317	4,317	4,317	4,317					
1980	4,121	3,752	3,881	4,311	4,593	4,499	4,121	4,121	4,121	4,121	4,121	4,121				
1981	4,285	3,687	3,835	4,331	4,671	4,563	4,359	4,285	4,285	4,285	4,285	4,285	4,285			
1982	4,412		3,789	4,351	4,749	4,627	4,386	4,272	4,412	4,412	4,412	4,412	4,412	4,412		
1983	3,802			4,370	4,827	4,690	4,414	4,264	4,242	3,802	3,802	3,802	3,802	3,802	3,802	
1984	4,367				4,905	4,754	4,442	4,257	4,211	3,932	4,367	4,367	4,367	4,367	4,367	4,367
1985	3,960					4,818	4,470	4,250	4,181	3,844	4,159	3,960	3,960	3,960	3,960	3,960
1986	4,017						4,498	4,242	4,150	3,755	4,142	4,041	4,017	4,017	4,017	4,017
1987	3,797							4,235	4,119	3,667	4,126	4,007	3,927	3,797	3,797	3,797
1988	4,030								4,088	3,579	4,109	3,974	3,867	3,775	4,030	4,030
1989	4,030									3,490	4,092	3,940	3,806	3,694	3,944	4,030
1990	3,980										4,076	3,907	3,745	3,613	3,929	3,864
1991	3,610											3,873	3,684	3,532	3,915	3,815
1992	4,053												3,623	3,451	3,900	3,767
1993	4,168													3,370	3,885	3,718
1994	4,331														3,871	3,670
1995	3,785															3,621
1996	4,266															
1997	4,063															
1998	3,389															
1999	3,475															
2000	3,616															
2001	3,782															
2002	3,337															
2003	4,102															
2004	3,785															
2005	3,772															
2006	3,481															
2007																
2008																
2009																
2010																
2011																
2012																

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Witnesses: I. Chan
J. Denomy
T. Ladanyi

Col. 18	Col. 19	Col. 20	Col. 21	Col. 22	Col. 23	Col. 24	Col. 25	Col. 26	Col. 27	Col. 28	Col. 29	Col. 30	Col. 31	Col. 32	Col. 33	Col. 34
ECCDD96	ECCDD97	ECCDD98	ECCDD99	ECCDD00	ECCDD01	ECCDD02	ECCDD03	ECCDD04	ECCDD05	ECCDD06	ECCDD07	ECCDD08	ECCDD09	ECCDD10	ECCDD11	ECCDD12
3,960																
4,017	4,017															
3,797	3,797	3,797														
4,030	4,030	4,030	4,030													
4,030	4,030	4,030	4,030	4,030												
3,980	3,980	3,980	3,980	3,980	3,980											
4,006	3,610	3,610	3,610	3,610	3,610	3,610										
4,017	3,762	4,053	4,053	4,053	4,053	4,053	4,053									
4,027	3,720	3,914	4,168	4,168	4,168	4,168	4,168	4,168								
4,038	3,677	3,914	4,018	4,331	4,331	4,331	4,331	4,331	4,331							
4,049	3,635	3,913	4,029	4,280	3,785	3,785	3,785	3,785	3,785	3,785						
4,059	3,593	3,912	4,040	4,351	4,118	4,266	4,266	4,266	4,266	4,266	4,266					
	3,550	3,912	4,051	4,423	4,155	4,299	4,063	4,063	4,063	4,063	4,063	4,063				
		3,911	4,062	4,495	4,192	4,374	4,091	3,389	3,389	3,389	3,389	3,389	3,389			
			4,074	4,567	4,229	4,449	4,085	3,579	3,475	3,475	3,475	3,475	3,475	3,475		
				4,638	4,266	4,524	4,079	3,458	3,318	3,616	3,616	3,616	3,616	3,616	3,616	
					4,303	4,600	4,073	3,338	3,156	3,376	3,782	3,782	3,782	3,782	3,782	3,782
						4,675	4,067	3,218	2,994	3,265	3,398	3,337	3,337	3,337	3,337	3,337
							4,061	3,097	2,832	3,154	3,293	3,379	4,102	4,102	4,102	4,102
								2,977	2,670	3,043	3,188	3,313	3,948	3,785	3,785	3,785
									2,508	2,931	3,083	3,247	4,043	3,939	3,772	3,772
										2,820	2,978	3,180	4,138	4,013	3,888	3,481
											2,873	3,114	4,232	4,086	3,932	3,658
												3,048	4,327	4,159	3,977	3,644
													4,422	4,232	4,021	3,629
														4,306	4,066	3,614
															4,110	3,599
																3,585

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UNDERTAKING J4.7

UNDERTAKING

Tr: 121

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.

RESPONSE

Please refer to the undertaking response to Exhibit J5.2.

Witnesses: I. Chan
J. Denomy
T. Ladanyi

UNDERTAKING J4.8

UNDERTAKING

Tr: 130

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.

RESPONSE

The gas prices used in the average use model are based on QRAM rates. The rate for a given year is the average of the QRAM rates for the four quarters of that year. The rate includes the monthly customer charge, delivery charge and commodity charge. The commodity charge for residential customers represents a smaller portion of the burner tip price of gas than the commodity charge for commercial customers. As a result, the growth rate in the residential price of gas will be different than the growth rate in the commercial price of gas. It should be noted that the history of actual gas prices shown at Exhibit C2, Tab 3, Schedule 1, Table 2 and Exhibit C2, Tab 3, Schedule 2 Table 4 display a similar pattern to the forecast values of those series. When gas prices increase, real residential prices increase by a lesser amount than real commercial prices. When gas prices decrease, real residential prices do not decrease by as much as real commercial gas prices.

Witnesses: I. Chan
J. Denomy
T. Ladanyi

UNDERTAKING J4.9

UNDERTAKING

Tr: 133

To provide the probability figures associated with the three variables that have T statistics on pages 13 and 14 of Exhibit K4.6.

RESPONSE

The tables below show the probability figures associated with each of the variables used in the equations on pages 13 and 14 of Exhibit K4.6.

In addition to examining the t-statistic for each variable in a regression model or a regression model's adjusted R-square statistic, a variety of other diagnostic statistics should be examined to determine whether or not a model is properly specified and a good predictor of average use.

For example, in the case of a multivariate regression model (i.e., a regression model with more than one independent variable) the F-statistic is used to determine the overall significance of the regression model. The F-statistic for each regression equation presented in the tables below show that the variables included in each equation are jointly statistically significant.

It should be noted that in addition to examining the t-statistics and F-statistics, the average use regression models have been subjected to a variety of other specification tests and forecasting accuracy tests. The specification tests run on each model can be found at Exhibit C2, Tab 3, Schedule 1, pages 29 to 30 for the Rate 1 models and Exhibit C2, Tab 3, Schedule 2, pages 34 to 36 for the Rate 6 models. Forecasting accuracy tests are explained at Exhibit C2, Tab 3, Schedule 1, pages 3 to 5 for the Rate 1 models and Exhibit C2, Tab 3, Schedule 2, pages 3 to 5 for the Rate 6 models.

The results of all of these tests indicate that the average use regression models are excellent predictors of average use. Each model exhibits a low RMSPE and passes all diagnostic tests indicating that the models are properly specified.

Witnesses: I. Chan
J. Denomy
T. Ladanyi

Western Region - Central Weather Zone

Long Run Equation

Variable	Coefficient	t-Statistic	P-value
C	-1.300	-2.108	0.051
LOG(CDD)	0.711	22.730	0.000
LOG(REAL_CRC_RPG)	-0.115	-8.296	0.000
LOG(WES20_VINT)	0.177	4.526	0.000
LOG(CRCE)	0.083	1.245	0.231
F Statistic	316.337		
Adjusted R-squared	0.984		
S.E. of regression	0.011		

Short Run Equation

Variable	Coefficient	t-Statistic	P-value
C	-0.004	-1.773	0.095
DLOG(CDD)	0.726	32.110	0.000
DLOG(REAL_CRC_RPG)	-0.119	-5.939	0.000
ECM_WES20(-1)	-0.701	-2.742	0.015
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	P-value
C	-2.764	-3.168	0.006
LOG(CDD)	0.709	16.413	0.000
LOG(REAL_CRC_RPG)	-0.111	-3.249	0.005
LOG(CEN20_VINT)	0.251	5.671	0.000
LOG(CRCE)	0.266	2.792	0.014
LOG(TIME)	-0.017	-1.233	0.236
F Statistic	179.047		
Adjusted R-squared	0.978		
S.E. of regression	0.014		

Short Run Equation

Variable	Coefficient	t-Statistic	P-value
C	-0.001	-0.199	0.845
DLOG(CDD)	0.707	23.123	0.000
DLOG(REAL_CRC_RPG)	-0.084	-2.814	0.013
DLOG(CEN20_VINT)	0.155	1.177	0.258
ECM_CEN20(-1)	-1.156	-4.322	0.001
F Statistic	173.929		
Adjusted R-squared	0.973		
S.E. of regression	0.013		

UNDERTAKING J4.10

UNDERTAKING

Tr: 139

Provide normalized 2006 numbers, volumes, similar to table 1 on page 25 of 65 for as many months of actuals as available for 2006.

RESPONSE

Table 1 presents 2006 11&1 un-normalized (Col. 4) and normalized forecasts (Col. 5) of volumes and customers. The 2006 11&1 un-normalized forecast volumes of 11 569.7 10^6m^3 are forecast to be 305.4 10^6m^3 or 2.6% below the 2006 Bridge Year Estimate of 11 875.1 10^6m^3.

The unfavourable variance is primarily due to an unexpected warmer weather in 2006 than the bridge year estimate. On a weather-normalized basis, the 2006 11&1 forecast volumes are forecast to be 63.6 10^6m^3 or 0.5% above the 2006 Bridge Year Estimate. This variance is mainly due to some Rate 100 customers unexpectedly switching to Rate 6.

The majority of this rate switching is the result of the introduction and enforcement of new large volume contracts along with Appendix A of the Company's Rate Handbook for each terminal location during 2006 as well as the proposed rate design change for Rate 100. In the past, large volume distribution contracts were not signed by the customers themselves as they were covered off under the Gas Transportation Agreements.

In addition, Rate 100 customers did not need to pay contract demand charges. During the contract renewal period (fall 2006), there were a number of customers, in particular the apartment sector, that did not return the signed agreement as expected. Without a signed contract, the Company could no longer provide the Rate 100 contract rate to these customers and this resulted in customers being switched to Rate 6.

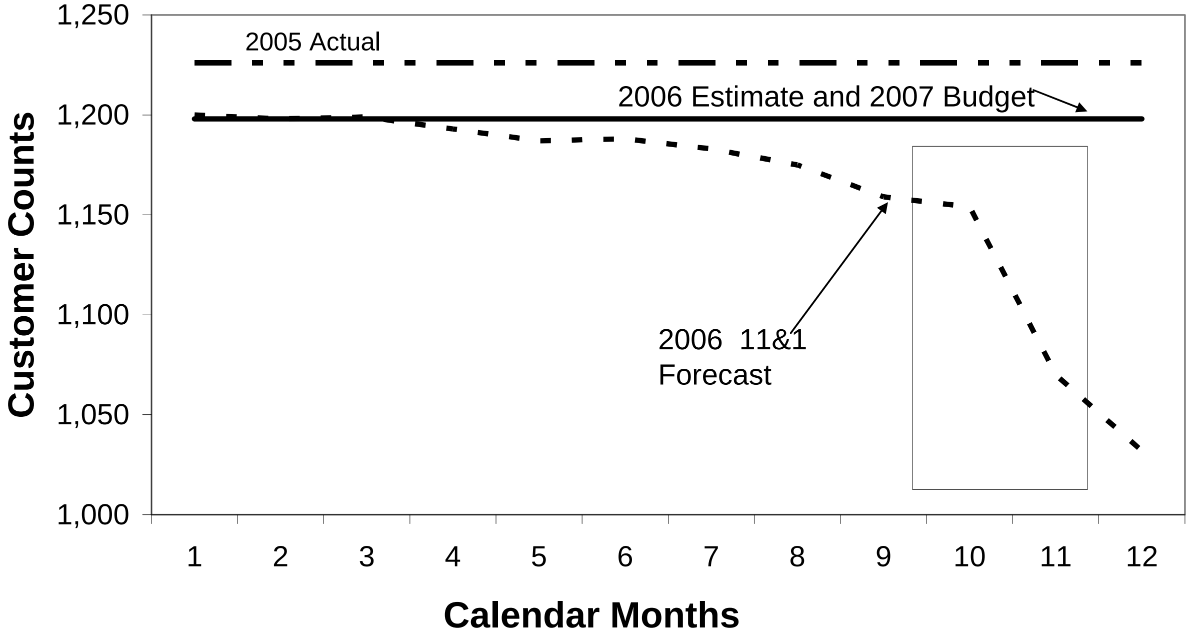
Figure 1 on the next page illustrates the unexpected rate switching for contract market apartment customers starting fall 2006 during the contract renewal period.

Witnesses: I. Chan
J. Collier
T. Ladanyi

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

	Col. 1 Calendar 2005 Actual	Col. 2 Calendar 2006 Board Approved Budget	Col. 3 Calendar 2006 Bridge Year Estimate	Col. 4 Calendar 2006 11&1 Forecast	Col. 5 Calendar 2006 Normalized 11&1 Forecast	Col. 6 Calendar 2007 Budget
General Service Volumes	8 019.5	7 932.8	7 758.6	7 521.6	7 816.5	7 625.8
Contract Volumes	4 190.3	4 387.9	4 116.5	4 048.1	4 122.2	4 131.7
Total Volumes, Gas Sales and Transportation	12 209.8	12 320.7	11 875.1	11 569.7	11 938.7	11 757.5
Customers, Gas Sales and Transportation (Average)	1 735 907	1 792 615	1 780 459	1 782 940	1 782 940	1 823 258
Gas Supply Degree Days	3,750	3,745	3,745	3,450	3,450	3,617

Figure 1
Contract Market Unlock Customers - Apartment Sector



Witnesses: I. Chan
J. Collier
T. Ladanyi

Filed: 2007-02-16
EB-2006-0034
Exhibit J5.1
Page 1 of 1

UNDERTAKING J5.1

UNDERTAKING

Tr: 4

Provide information to show 1.8 percent decline in average use between 2001 and 2005.

RESPONSE

As stated in Exhibit C1, Tab 3, Schedule, 1, normalized residential average use has decreased by an average of 1.8% per year for each residential customer during the volatile and high natural gas price period between 2001 and 2005. Table 1 below shows the residential average use from 2001 to 2005 on a test year weather normalized basis, as filed at Exhibit C5, Tab 2, Schedule 3.

Table 1
Residential Normalized Average Use - Calendar Year

	Col. 1 2000	Col. 2 2001	Col. 3 2002	Col. 4 2003	Col. 5 2004	Col. 6 2005
Residential (m^3)	3,043	2,940	2,929	2,900	2,850	2,779
Year over Year Change		(103)	(11)	(29)	(50)	(71)
Year over Year % Change		-3.38%	-0.37%	-0.99%	-1.72%	-2.49%

Average percentage decline in average use per year
during 2001-2005 (5-year volatile and high gas prices period)
= (1/5)*((-3.38%)+ (-0.37%)+(-0.99%)+(-1.72%)+(-2.49%))
= -1.8%

Witnesses: I. Chan
T. Ladanyi

UNDERTAKING J5.2

UNDERTAKING

Tr: 6

A similar thing for the gas price impacts shown in tables 4, 5 and 6, either individually or in aggregate, of adjusting the real commercial price to reflect actual 2006 and the updated forecast for 2007/2008.

RESPONSE

The response to undertaking J4.7 has been incorporated herein, in order to facilitate the review of the requested price impacts for the General Service Customers. It should be noted that general service volumetric changes associated with changing the price can vary each year as a result of changes to customer mix and actual price elasticity between different customer groups. Therefore, the impact provided here is only relevant to 2007 Test Year budget volume profile.

Table 1 reflects the requested Actual 2006 prices and the updated forecast for Calendar 2007 prices as presented at Exhibit J3.6. In addition, this updated Calendar 2007 price forecast has incorporated the Company's latest 2007 first quarter Quarterly Rate Adjustment Mechanism ("QRAM") rates. Overall, the cumulative forecast year over year percentage change in prices between 2007 and 2006 were slightly lower than the original filed numbers.

As shown in Table 2, historically prices can increase or decrease during the remaining quarters. Table 2 presents the full year actual annual average QRAM utility prices that were mentioned during the hearing. This table has demonstrated that not only 2006 prices were significantly higher than 2005, they were also at historic high as shown here and Figure 1 at Exhibit C1, Tab 3, Schedule 1. Since all forecasters at Exhibit J3.6 are publishing and predicting a further increase in prices during 2007, customers still perceive gas prices are increasing and high.

Table 3 illustrates the cumulative impact of updated 2006 actual and 2007 forecast gas prices on the changes in General Service Normalized Consumption. This cumulative change represents the difference between the combined impact of updated 2006 actual gas prices on the 2006 Bridge Year Estimate and 2007 forecast gas prices on the 2007 Test Year Budget Volume and the original filed Estimate and Budget Volume, holding other things constant. On the other hand, Tables 3-6 at Exhibit C1, Tab 3, Schedule 1 present the incremental volumetric impact between 2007 Test Year Budget and 2006 Bridge Year Estimate.

As in the past, the filed test year volume budget represents the forecast that integrates all of the actual experiences and the best known information at the time the budget was developed. Therefore, Table 3 does not characterize the updated volume budget as it has not incorporated the actual weather experience as stated at Exhibit J4.10 which is the major driver variable of the total volume budget as displayed at Exhibit C3, Tab 2, Schedule 3, page 2. These unfavourable volumetric impacts would more than offset the moderate positive price impact reported in Table 3.

Table 1
Real Natural Gas Price Variable Assumptions - Original Filed vs Updated
Calendar Year Over Year Percentage Change

Item	Col. 1	Col. 2 2006	Col. 3 2007	Col. 4 = 2+3 Cumulative
1.1	Real Residential Natural Gas Price - Original	12.2%	8.5%	20.7%
1.2	Real Commercial Natural Gas Price - Original	13.8%	9.6%	23.4%
1.3	Real Residential Natural Gas Price - Update	8.4%	6.8%	15.2%
1.4	Real Commercial Natural Gas Price - Update	9.4%	6.5%	15.9%

Note:
Calendar year 2007 data is comprised of fiscal year 2007's first nine months actual data for the period of January to September 2007 and first three months of fiscal 2008 data for the period of October to December 2007.

Witnesses: I. Chan
J. Denomy
T. Ladanyi

Table 2

Enbridge Gas Distribution Quarterly Rate Adjustment Mechanism (QRAM) Utility Prices ($\$/10^3m^3$) - Nominal Price

Calendar Year	Q1	Q2	Q3	Q4	Annual Average	Year over Year % Increase
2005	356.327	319.285	355.705	396.567	356.971	
Docket Number	EB-2004-0492	EB-2005-0299	EB-2005-0291	EB-2005-0461		
2006	484.195	399.582	381.692	381.692	411.790	15%
Docket Number	EB-2005-0524	EB-2006-0035	EB-2006-0099	EB-2006-0195		
2007	349.047					
Docket Number	EB-2006-0288					

Table 3

Cumulative Impact of Updated Gas Prices on the Changes in General Service Normalized Consumption (10^6m^3)

Sector	Cumulative Price Impact
Residential	31.3
Apartment	2.0
Commercial	0.4
Industrial	0.2
Total General Service	33.9

Witnesses: I. Chan
J. Denomy
T. Ladanyi

UNDERTAKING J5.3

UNDERTAKING

Tr: 21

Provide the impact on the deficiency of using a degree day methodology that consists of a 50/50 weighting between the 20-year trend and the existing approved de bever methodology.

RESPONSE

Table 1 below provides an update to Exhibit K4.2 by including the requested degree day methodology that consists of a 50/50 weighting between the 20-year trend and the existing approved de Bever methodology (Column 9).

Table 1
Comparison of Ten 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 Avg(20-Yr, de Bever)	Col. 10 20-Yr Trend
1.1	Total operating costs incurred by EGDI in utilizing the method ('$000)	There are no material or significant operating costs incurred by using each of the degree day forecasting methods.									
1.2	Total Bill Impact on a Typical Residential Customer vs 20-Yr Trend (%)	1.5%	3.2%	0.2%	1.4%	3.3%	5.3%	2.6%	1.9%	1.6%	0.0%
1.3	Delivery Bill Impact on a Typical Residential Customer vs 20-Yr Trend (%)	0.3%	0.6%	0.0%	0.3%	0.6%	0.9%	0.5%	0.3%	0.3%	0.0%
1.4	Impact on Revenue Requirement vs 20-Yr Trend (%)	0.4%	0.7%	0.0%	0.3%	0.7%	1.1%	0.5%	0.4%	0.3%	0.0%
1.5	Impact on Revenue Deficiency vs 20-Yr Trend ($M)	12.3	21.2	1.6	9.7	22.1	35.0	17.6	12.6	10.8	0.0
1.6	Volumetric Impact vs 20-Yr Trend $(10^6 m^3)$	192.1	331.7	25.0	151.8	345.6	548.2	275.0	196.5	168.6	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	-2.1	-12.9

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

UNDERTAKING J6.1

UNDERTAKING

Update Table 4 of Exhibit E2, Tab 1, Schedule 1 for the actual normalized utility return on equity.

RESPONSE

Col. 1	Col. 2	Col. 3	Col. 4
	Test Year	Normalized Actual ROE Utility EBIT Interest Coverage (times interest coverage)	EBIT Margin Above 2 Times Coverage ($ Millions)
1.	1993	2.60	75.3
2.	1994	2.43	56.0
3.	1995	2.45	62.6
4.	1996	2.50	76.5
5.	1997	2.53	84.3
6.	1998	2.49	80.5
7.	1999	2.38	64.7
8.	2000	2.36	52.6
9.	2001	2.26	41.3
10.	2002	2.50	70.8
11.	2003	2.19	28.4
12.	2004	NA	NA
13.	2005	2.18	27.6

Witness: B. Boyle

UNDERTAKING J6.2

UNDERTAKING

Tr: 122

To provide the budget for the 2006 business development and strategy, as adjusted or incorporating the capitalized amount referred to for (1) the prefiled estimate and (2) for the actual.

RESPONSE

The Business Development and Strategy 2006 amounts (in $000’s) are as follows:

	2006 Estimate	2006 Actual
Operating & Maintenance Expense	1,667	1,668
Total Capital	2,187	2,014
Total Expenses (O&M + Capital)	3,854	3,682

Witnesses: S. Clinesmith
P. Green
K. Lakatos-Hayward
N. Ryckman
P. Squires

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Exhibit J6.3
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UNDERTAKING J6.3

UNDERTAKING

Tr: 126

Provide reasons for the decrease in the energy opportunities budget from the 2005 actual figure to the 2006 bridge year estimate of 1.177 million, as found on Table 1 on page 2 of 10 in the Pollution Probe Document Book, Tab 3.

RESPONSE

The variance in the 2006 Bridge Year Estimate compared to the 2005 Actual amounts is primarily the result of winding down the LNG heavy duty trucking demonstration project undertaken in 2005 and the deferral of distributed generation activities to synchronize with the Ontario Power Authority's Clean Energy Standard Offer Program ("CESOP") which is expected to be released in 2007 instead of 2006.

Witnesses: S. Clinesmith
P. Green
N. Ryckman
P. Squires

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EB-2006-0034
Exhibit J7.1
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UNDERTAKING J7.1

UNDERTAKING

Tr: 6

To provide additional year 2006 to Undertaking J6.1

RESPONSE

The information required to add 2006 to Undertaking J6.1 is not scheduled to be developed by the Company prior to its requirement in the RRR filing of year end information due in late April, 2007. Due to the volume of work that would need to be undertaken in order to provide this information within the time limitations of this proceeding, the Company is unable to produce the requested information prior to the end of April.

Witnesses: B. Boyle
P. Carpenter
J. Denomy

UNDERTAKING J7.2

UNDERTAKING

Tr: 13

To review evidence of RP-2002-0158 and confirm whether there were changes in business risk sufficient to justify an increase in equity ratios

RESPONSE

The Company has reviewed the record of RP-2002-0158 and confirms that the equity component of Enbridge Gas Distribution's capital structure was not an issue in that application and therefore no evidence was brought forward in that application on the equity ratio.

Witnesses: B. Boyle
P. Carpenter
J. Denomy

UNDERTAKING J7.3

UNDERTAKING

Tr: 53

Recalculate the interest coverage ratios in column 9 in items in Exhibit E2, Tab 1, Schedule 1, Appendix 3, assuming that amounts paid for corporate cost allocation in 2002-2006 inclusive are to be added to the amounts in Column 8, along with the amounts paid to CWLP in excess of board-allowed amounts for customer support

RESPONSE

The table below shows the Column 9 figures in Exhibit E2, Tab 1, Schedule 1, Appendix 1, page 3 as presented by the Company in the pre-filed evidence and recalculates the EBIT interest coverage ratio in this column for each of the years 2002-2006 by mathematically adding to EBIT the amounts paid for corporate cost allocation and to CWLP in excess of board-allowed amounts in the respective years. The Company notes, however that since the original Column 9 figures are the forecast utility allowed figures that have not been adversely impacted by the amounts paid for corporate cost allocation and to CWLP in excess of board-allowed amounts, this mathematical exercise is an incorrect calculation of the EBIT coverage since it does not use the correct starting point.

The reason for this is that in order to “addback” the amounts paid for corporate cost allocation and to CWLP in excess of board-allowed amounts for customer support, you need to start with a calculation that included this negative impact. Since the original column 9 results did not reflect this negative impact on EBIT, it is incorrect to add these amounts to EBIT since you are effectively double counting the impact of the adjustment.

Year	Original Column 9 EBIT Interest Coverage Ratio	Amounts Paid for Corporate Cost Allocation and to CWLP in Excess of Board Allowed Amounts ($ millions)	Mathematical Recalculation of Column 9 EBIT Interest Coverage Ratio
2002	2.24	-	2.24
2003	2.18	7.0	2.23
2004	N/A	7.1	N/A
2005	2.19	17.0	2.30
2006	2.10	27.4	2.27

Witnesses: B. Boyle
P. Carpenter
J. Denomy

Filed: 2007-02-26
EB-2006-0034
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Page 1 of 1

UNDERTAKING J7.4

UNDERTAKING

Tr: 114

2006 actuals for Line 1

RESPONSE

In 2006, the Company recorded 3,540 high efficiency furnace "added load" participants.

Witnesses:	S. Clinesmith
	P. Green
	N. Ryckman
	P. Squires

UNDERTAKING J7.5

UNDERTAKING

Tr: 117

To provide clarification for Column 7

RESPONSE

Column 7 represents the distribution margin that will be realized from each of the initiatives over the next 5 years. The first year is assumed to be half effective and the remaining 4 years are fully effective. The Company defines distribution margin, within this context, as total revenues less total gas costs. To determine distribution margin on a rate class basis, the Company must take into consideration how costs have been allocated to each rate class and how costs are recovered from the customer charge, delivery charge, load balancing and gas supply commodity charge for each rate class.

For purposes of the analysis included in the response to Board Staff Interrogatory #25 at Exhibit I, Tab 1, Schedule 25, page 3 of 3, distribution margin rates are provided by the Regulatory Affairs department. These margin rates are based on the existing Board approved rates, however, they are restated to reflect what the distribution rate would be if all of the distribution costs were recovered exclusively through the delivery rates for each rate class. This calculation is required as some gas costs such as Union storage and UUF are recovered in the delivery charge of rates and some distribution related costs are recovered through load balancing and gas supply commodity charges.

The distribution margin rates used in this analysis differ depending on the initiative and rate class. They are higher for initiatives which add new customers to the gas distribution system. In such a scenario, the revenues generated from the newly attached customer will include both the monthly customer charge as well as delivery charges associated with serving the new load. If an initiative adds load that is incremental to an existing customer, the customer already pays the monthly customer charge. In this scenario the additional revenues will be generated from incremental gas delivery over and above the customers existing load and the margin rates are lower.

Witnesses: S. Clinesmith
J. Collier
P. Green
N. Ryckman
P. Squires

UNDERTAKING J7.6

UNDERTAKING

Tr: 123

Explain the difference in volumes anticipated from water heaters on lines 7, 10 and 11

RESPONSE

The assumed volume per participant for the water heater programs on Lines 7 and 10 of the response to Board Staff Interrogatory # 25 at Exhibit I, Tab 1, Schedule 25 page 3 is 679 m^3. This represents the expected annual load from a tank-style water heater. The assumed volume per participant for the water heater program on Line 11 of Exhibit I, Tab 1, Schedule 25 page 3 is 396 m^3 per year, which is the expected annual load from a tankless or instantaneous water heater.

Witnesses: S. Clinesmith
P. Green
N. Ryckman
P. Squires

UNDERTAKING J7.7

UNDERTAKING

Tr: 138

To verify TRC amount of $10.2 million for furnace and water heater lines

RESPONSE

The TRC calculated for the EnergyLink^{TM} furnace and water heater lines is $13.46 million. This amount includes TRC benefits of $9.70 million for furnaces and $3.76 million for water heaters (see Exhibit J9.2, p. 2, Column 9, Rows 1 and 10).

Fixed costs of $1.04 million included in the EnergyLink^{TM} program budget shown at Exhibit I, Tab 1, Schedule 25, Row 13, Column 5, are general in nature and are not specific to any initiative or end use technology.

Witnesses: S. Clinesmith
P. Green
P. Squires
N. Ryckman

UNDERTAKING J7.8

UNDERTAKING

Tr: 140

To provide TRC for fireplaces under EnergyLink Program

RESPONSE

The Total Resource Cost ("TRC") calculated for EnergyLink^{TM} fireplaces is ($5.87) million and the life NPV is $0.78 million.

The primary reason for the negative TRC value for fireplaces is that one of the underlying inputs is an assumption that a number of the gas fireplace installations are occurring where currently no fireplace exists, and therefore, the installation would not have avoided costs but would have added natural gas costs.

The TRC test does not take into account other benefits that motivate a potential customer to make the decision to install a natural gas fireplace (e.g., ease of use, convenience, resale value of home etc.) or the impact of reduced particulates where a natural gas fireplace replaces a wood burning unit.

The weakness of the TRC Test is noted in the California Standard Practice Manual: Economic Analysis Of Demand Side Programs And Projects at page 21 of the document whereby it states:

> "The treatment of revenue shifts and incentive payments as transfer payments, identified previously as a strength, can also be considered a weakness of the TRC test. While it is true that most supply-side cost analyses do not include such financial issues, it can be argued that DSM programs should include these effects since, in contrast to most supply options, DSM programs do result in lost revenues.
>
> In addition, the costs of the DSM "resource" in the TRC test are based on the total costs of the program, including costs incurred by the participant. Supply-side resource options are typically based only on the costs incurred by the power suppliers.
>
> Finally, the TRC test cannot be applied meaningfully to load building programs, thereby limiting the ability to use this test to compare the full range of demand-side management options."

For the reasons stated in the Company's oral evidence and this response, the Company does not support the use of TRC as a primary screen for added load programs.

Witnesses: S. Clinesmith
P. Green
N. Ryckman
P. Squires

UNDERTAKING J8.1

UNDERTAKING

Tr: 39

Either confirm fireplace and lifestyle products’ TRC, when delivered through the EnergyLink mechanism, is negative; or provide a calculation of the TRC for each of those products including attributable program costs of the EnergyLink program.

RESPONSE

Confirmed (please see the response to Exhibit J9.2).

Witnesses: S. Clinesmith
P. Green
N. Ryckman
P. Squires

UNDERTAKING J9.1

UNDERTAKING

Tr: 54

Provide binder of scripts relating to EnergyLink

RESPONSE

Please see Attachment 1 “Sales Enquiry Centre Leads Referrals For EnergyLink^{TM}” and Attachment 2 “Enbridge – EnergyLink^{TM} - Contractor Referral Program - Job Aid”

Witnesses: W. Cain
P. Green
K. Lakatos-Hayward
S. McGill

SALES ENQUIRY CENTRE LEADS REFERRALS FOR ENERGYLINK

Current EnergyLink Offerings:	**Residential:** **Air Conditioning, Boiler, Furnace, Fireplace, In Floor Radiant, Water Heater, Rental Water Heater, Generator, Gas Hookup (e.g Range, Dryer).**	**Commercial:** **Heating(Unit Heaters, Space Heater, Radiant Tube Heater, Rooftop units) Water Heating, Cooling**
Outside of Current EnergyLink Offerings:	**Advise the customer that we hope to add more appliances to our referral line-up in the near future.**	**At this time they would need to contact a heating contractor or retailer listed in their local yellow pages or by calling the Heating, Refrigeration and Air Conditioning Institute (HRAI) at 1-877-411-4722 or visit their web site @ www.hrac.ca For fireplace (except for stoves) and appliance retailers, visit the Hearth, Patio and BBQ Association (HPBA) web site @ www.hpba.org**

ENQUIRIES FROM CUSTOMER TO SEC COORDINATOR

Call #	**Customer**	**SEC Coordinator**	**Action Required**
1	I am interested in receiving a quote to **purchase**, **install or service natural gas equipment** in my home or small business.	Do you currently have natural gas installed at your property or are you aware if natural gas is available on your street?	**IF YES**: * confirm address in **OSIM** (If required), * enter all information in **ENERGYLINK** for referral **IF NO:** ***** transfer the customer back to **ABSU 1-888-427-8888 (Press # 4)** for gas availability. * Give customer the EnergyLink phone number to call back if gas is available and the customer would like a referral.
2	Can I only receive **quotes for particular furnace models**, such as Carrier or Trane?	Energylink is not product specific.	If you are looking for a particular brand, please go to the manufacturer website.
3	I am interested in purchasing a stove or gas dryer.	Advise the customer to check appliance store or any major retailer. Ask the customer if they are looking for a contractor to install a stove or gas dryer.	**IF YES**: * confirm address in **OSIM** (If required), * enter all information in **ENERGYLINK** for referral

4	I am interested in purchasing a **BBQ** (or any other product not currently listed for Energylink, such as: **BBQ'S, RANGES, CAMPFIRES, LAMPS, PATIO HEATERS, TANKLESS WATER HEATERS, POOL HEATERS).**	Those products are **not available via EnergyLink** at this point in time.	We hope to add more appliances to our referral line-up in the near future. At this time please contact a heating contractor or retailer listed in the yellow pages or call the Heating, Refrigeration and Air Conditioning Institute (HRAI) at 1-877-411-4722 or visit their web site @ www.hrac.ca For fireplace and appliance retailers, visit the Hearth, Patio and BBQ Association (HPBA) we site @ www.hpba.org.
5	I submitted a request on-line and f**orgot the names of the contractors** who were supposed to phone me.	Ask for the customers name, address, requested referral and what date the request was submitted.	Access APRIMO application and search for the information. * **EnergyLink Membership Status "Suspended by EGD" means only that a contractor is not active at this point.**
6	I need to **reschedule an appointment** I made with my contractor.	Advise the customer that they will need to reschedule their appointment by phoning their contractor directly. If the customer does not know the contractor's phone number, the SEC Coordinator can provide it them.	Access **APRIMO** application and search for the information. *** EnergyLink Membership Status "Suspended by EGD" means only that a contractor is not active at this point.**
7	I need to **cancel or change a referral reques**t that I entered on the ENERGYLINK website.	Advise the customer that you cannot CANCEL the REFERRAL, Advise them they will be contacted by the contractors, as the referral goes directly to them at the time of the initial request. Tell them when the contractor calls let them know at that time, or they can call the contractors and tell them they would like to cancel	Access **APRIMO** application and search for the information. If customer does not remember the contractors *** EnergyLink Membership Status "Suspended by EGD" means only that a contractor is not active at this point.**
8	Will I be billed by Enbridge on a gas bill for any work performed by the EnergyLink contractor?	**No.** The EnergyLink Program provides our customers with a website and a phone line that will link them to HVAC contractors who have been pre-screened by Enbridge. A referral from EnergyLink will assure our customers that the contractor they're hiring is independent and fully qualified to sell, install or service natural gas equipment and products.	If the customer insists that somebody is being billed on the gas bill than explain that there's only one contractor, Direct Energy, that is allowed to bill on the gas bill at the present time.
9	What's the advantage of renting versus buying the water heater?	Renting the water heater instead of buying allows you to save on upfront costs, such as basic installation and on any repairs.	**IF Customer is inquiring about the quotes**: * confirm address in **OSIM** (If required), * enter all information in **ENERGYLINK** for referral

10	My water heater is leaking.	Do you rent that water heater or you own it?	**IF Customer owns the water heater**: * advise him that if he is looking to purchase or repair the water heater the EnergyLink Program will assist him and can provide 3 HVAC contractors who have been pre-screened by Enbridge * confirm address in **OSIM** (If required), * enter all information in **ENERGYLINK** for referral **IF Customer rents the water heater**: * advise him to confirm his rental provider (there is typically a sticker placed on the tank) and to call that provider.
11	Customer is inquiring about equipment maintenance programs or "service protection plans"	I can give you the names of 3 contractors but they might not provide this service. You have to check with them.	**IF customer is interested**: * confirm address in **OSIM** (If required), * enter all information in **ENERGYLINK** for referral
12	I **haven't been contacted** by any (or just one) contractor about natural gas equipments costs.	Ask the caller if it has been more than 1 BUSINESS DAY since they submitted their request. If so then advise the customer that the local Enbridge Sales Department will have to look into the problem.	Take the customer name, phone number and e-mail address and forward the inquiry to the local Enbridge Sales Department through **ISIGHT**. Advise the customer they will hear back from an Enbridge employee by the next business day.
13	I tried to access the **ENERGYLINK website**, but the website is down.	Advise the customer to try again later and that we will notify the EGD IT department about the system outage.	SEC Coordinator will call to **Enbridge's IT** Department. If our **ENERGYLINK** website is working enter referral for customer.
14	I'm **not happy with the work done** by my contractor (eg: mud on carpet) and want to file a complaint to ENBRIDGE	Advise the customer they will hear back from an **ENBRIDGE EMPLOYEE** by the next business day.	Enter a complaint in **ISIGHT** and forward the complaint to the local Enbridge Sales Department.
15	I've been contacted by a contractor but he doesn't do the product.	Advise the customer that the local Enbridge Sales Department will have to look into the problem. They will call him back within 1 business day.	Send an email to appropriate Area Sales Analyst.
16	Customer calls and is asking questions of a technical gas related nature.	Put customer on hold. Consult the question with Rick. Follow up with the customer according to Rick's suggestions. If sending Draft to Technical Desk advise the customer that Enbridge Technical Desk will be contacting him to answer his questions.	If needed send Draft Request to Technical Desk via email using Draft template.
17	What setting should I turn my thermostat to as I am going to be away for 7 weeks (in other words, how low could I turn it down)	To answer that question check document *Vacation Thermostat Settings* in Sales Enquiry Centre shared drive HelpLine Tips folder.	S:\Sales Enquiry Centre\HelpLine Tips

18	Customer Benefits of using EnergyLink	Advise the customer the benefits are that a contractor was prescreened by Enbridge to ensure that they have the appropriate licenses to install and repair the natural gas equipment and they have appropriate insurance and they are credit worthy.	n/a
19	Customer is interested in purchasing and financing a furnace.	Advise the customer that you can provide him with the names of 3 contractors and they will be able to discuss the details re:purchasing and financing the furnace with him.	Create EnergyLink Contractor Referrals.
20	How do I know that this contractor is better then the other one. I had bad experience with that particular contractor.	Advise the customer that all our contractors that are Energylink members were prescreened by Enbridge and they are fully qualified. Some people have great experience with that contractor , some people have bad experience. Enbridge follows up on those bad experiences if they had been reported by the customer.	Enter EnergyLink complaint in iSight if customer insists.
21	Customer doesn't like any of three contractors selected by EnergyLink Contractor Referral Program.	Advise the customer that you can provide him with another 3 contractors but you have to send the referrals to the first 3 contractors first. Explain to the customer how the Contractor Referral Program works. Advise the customer that he can check HVAC or yellow pages for other contractors.	Create EnergyLink Contractor Referrals.
22	Customer says they know they received a letter offering the rebate for Non Customers on Main but now can't find it.	This information should be gathered by SEC and given to Sheila or Rick. Advised the customer that Sales Enquiry employee will contact him within one business day.	Sheila or Rick will contact the customer.

Enbridge - EnergyLink - Contractor Referral Program - Job Aid

Customer Inquiry:	CSR should:
Converting to natural gas	For all natural gas conversion requests: • Transfer to Enbridge Sales
If the customer is already on gas and wants to purchase or service - Furnace or Air Conditioner	**Purchase requests:** Does customer mention they have DEEHS maintenance contract, and wish to speak/deal with them? • Yes, the customer mentions they have a maintenance contract with DEEHS and wishes to deal/speak with them: • Advise customer to contact Direct Energy No, the customer makes no mention that they have a maintenance contract with DEEHS or wants to deal with them: • Transfer the caller to the EnergyLink Sales Enquiry Centre **Service requests:** Ask the customer if they currently have a maintenance contract on that appliance • If yes, refer customer back to that service provider • If no, transfer the caller to the EnergyLink Sales Enquiry Centre
Purchasing, servicing, or installation - Rental Water Heater	If the customer already has an existing rental water heater, and is not looking to change providers: • Advise customer to contact their existing rental service provider Any service inquiries: • Advise customer to contact their service provider New rental water heater installations or replacements not covered above: • Transfer the caller to the EnergyLink Sales Enquiry Centre

Customer Inquiry:	CSR should:
If the customer is already on gas and wants to purchase, install or service other gas appliances	For all other natural gas equipment (for example: stove, fireplace, dryer, pool heater, barbeque): Transfer the caller to the EnergyLink Sales Enquiry Centre

Customer request/inquiry:	CSR action:
Specifically mentions EnergyLink Program	• Transfer the caller to the EnergyLink Sales Enquiry Centre
General inquiry about contractor referral	• Transfer the caller to the EnergyLink Sales Enquiry Centre
Claim against contractor referred through EnergyLink	• **Do not** send the customer a claims form • Instead, transfer the caller to the EnergyLink Sales Enquiry Centre
Claim against Enbridge re: EnergyLink	• **Do not** send the customer a claims form • Instead, transfer the caller to the EnergyLink Sales Enquiry Centre

UNDERTAKING J9.2

UNDERTAKING

Tr: 67

Replace numbers in the EnergyLink^{TM} section of K9.4 to reconcile with previous evidence

RESPONSE

The attached table presents the corrected values for the table originally presented at Exhibit K9.4, and reconciles the totals to amounts shown at Exhibit I, Tab 1, Schedule 25, page 3.

Witnesses: S. Clinesmith
P. Green
N. Ryckman
P. Squires

Consolidated Residential Growth Initiatives 2007

Derived from Exhibit K9.4

Item	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
		Direct Programs ("Business as Usual" programs)				**EnergyLink Programs**				**All Programs**			
		Volume	**Participants**	**NPV**	**TRC**	**Volume**	**Participants**	**NPV**	**TRC**	**Volume**	**Participants**	**NPV**	**TRC**
1	*High Efficiency Furnaces*	6.49	3,174	$2.31	$22.95	2.45	1,200	$1.42	$9.70	8.94	4,374	$3.73	$32.65
2	*ECM*	0.33	5,000	$0.19	($0.54)	0.05	262	$0.03	($0.27)	0.38	5,262	$0.22	($0.81)
3	*Mid Efficiency Furnaces*	0.30	123	$0.11	$1.11					0.30	123	$0.11	$1.11
4	*Fireplace*	1.77	5,303	$0.61	($6.12)	1.77	5,303	$0.78	($5.87)	3.54	10,606	$1.39	($11.99)
5	*Grill/BBQ*	0.07	1,477	$0.01	($0.18)					0.07	1,477	$0.01	($0.18)
6	*Range/Dryer/Front Load Washer*	1.26	12,966	$0.49	$0.03	1.25	12,966	$0.55	$0.04	2.51	25,932	$1.04	$0.07
7	*Low Income Water Heaters*	0.78	1,150	($0.56)	$0.38					0.78	1,150	($0.56)	$0.38
8	*Interior Construction Heat New*	10.60	18,644	$0.80	$5.19					10.60	18,644	$0.80	$5.19
9	*Interior Construction Heat Comm.*	0.37	107	$0.00	$0.35					0.37	107	$0.00	$0.35
10	*Fuel Switching Water Heaters*	1.03	1,518	($0.06)	$1.79	1.70	2,500	$0.60	$3.76	2.73	4,018	$0.54	$5.55
11	*Water Heaters*	0.99	2,500	$0.26	$1.49					0.99	2,500	$0.26	$1.49
12	*Outdoor Living/Garage Heating/Pool Heating*	0.33	550	$0.04	($1.11)	0.78	700	$0.34	($1.57)	1.11	1,250	$0.38	($2.68)
13	**Total Programs**	**24.32**	**52,512**	**$4.20**	**$25.34**	**8.00**	**22,931**	**$3.73**	**$5.79**	**32.32**	**75,443**	**$7.93**	**$31.13**
14	**EnergyLink General Program Costs**							($1.04)	($1.04)				
15	**EnergyLink Capital Costs**							($2.20)	($2.20)				
16	**EnergyLink Tax and Tax Shield Implications**							$1.85					
17	**Variance due to analysis methodology** **(i.e.,blending of measure life, incremental costs in aggregate for the EnergyLink program screening in Ex I Tab 1 Sch 25)**							($0.29)	($1.25)				
18	**Grand Total Programs**	**24.32**	**52,512**	**$4.20**	**$25.34**	**8.00**	**22,931**	**$2.06**	**$1.30**	**32.32**	**75,443**	**$6.26**	**$26.64**

Notes:

1) The primary reason for the negative TRC values for these end uses is that one of the underlying assumptions is that a number of the installations are occurring where currently no fireplace or lifestyle product exists, and therefore these installations would not have avoided costs but would have added natural gas costs. As the Company stated during the oral phase of the hearing, the TRC test does not take into account other benefits that motivate a potential customer to make the decision to install a natural gas fireplace or lifestyle product (e.g., ease of use, convenience, resale value of home etc.).

2) The weakness of the Total Resource Cost Test is noted in the California Standard Practice Manual: Economic Analysis Of Demand-side Programs And Projects at page 21 of the document whereby it states: "The treatment of revenue shifts and incentive payments as transfer payments, identified previously as a strength, can also be considered a weakness of the TRC test. While it is true that most supply-side cost analyses do not include such financial issues, it can be argued that DSM programs should include these effects since, in contrast to most supply options, DSM programs do result in lost revenues. In addition, the costs of the DSM "resource" in the TRC test are based on the total costs of the program, including costs incurred by the participant. Supply-side resource options are typically based only on the costs incurred by the power suppliers. Finally, the TRC test cannot be applied meaningfully to load building programs, thereby limiting the ability to use this test to compare the full range of demand-side management options."

UNDERTAKING J9.3

UNDERTAKING

Tr: 70

To E-mail the letter received from HVAC coalition indicating that they didn't want reference to their name on the Enbridge website

RESPONSE

Attached is the email from HRAI indicating that they didn't want HRAI's name or logo referenced on the EnergyLink^{TM} site. Subsequent to the email dated June 1st 2006, HRAI did not contact Enbridge again regarding EnergyLink^{TM}.

Included for context as Attachment 1 are screenshots of the proposed prototype that was presented to them in late May. The proposal if accepted would have provided a high degree of visibility to HRAI via the program and a role to help pre-screen the contractors.

Glenda Mulligan <gmulligan@hrai.ca>
06/01/2006 04:30 PM
To
'Paul Green' <Paul.Green@enbridge.com>
cc
Martin Luymes <mluymes@hrai.ca>, "Nancy McKeraghan (nancymckeraghan@rogers.com)" <nancymckeraghan@rogers.com>
Subject
Follow up from meeting

Hi Paul:

Further to our meeting regarding Enbridge's proposed EnergyLink program, we regret that the meeting ended in a stalemate today.

At this time, we request that all reference to HRAC including the logo be removed from the web-site prototype until we consult further with the industry and our Executive Committee.

Witnesses: W. Cain
P. Green
K. Lakatos-Hayward
S. McGill

Thank you for hosting the meeting today and we will be in touch.

Glenda Mulligan
Program Coordinator, Contractors Division (HRAC)
2800 Skymark Avenue
Building 1, Suite 201
Mississauga, ON L4W 5A6

Telephone: (905) 602-4700 or 1-800-267-2231, ext. 233

Ask me about www.hvacrjobs.ca

Witnesses: W. Cain
P. Green
K. Lakatos-Hayward
S. McGill

Filed: 2007-02-26
EB-2006-0034
Exhibit J9.3
Attachment 1
Page 1 of 8

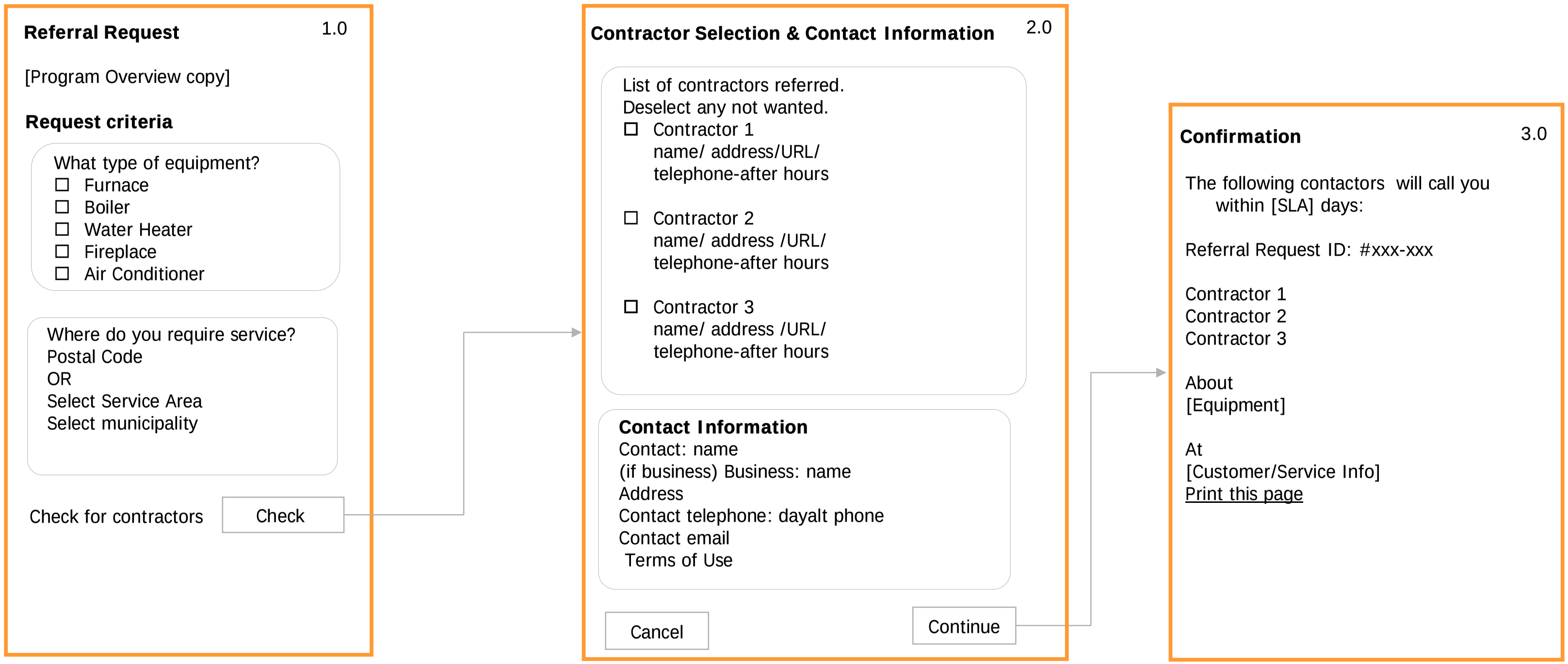
Creative Design Specifications

EnergyLink Referral System User Experience Alternative

Version 3.5 DRAFT
May 31, 2006

Referral User Flow – High-level screens

Filed: 2007-02-26
EB-2006-0034
Exhibit J9.3
Attachment 1
Page 2 of 8



Referral Request 1.0

[Program Overview copy]

Request criteria

What type of equipment?
- ☐ Furnace
- ☐ Boiler
- ☐ Water Heater
- ☐ Fireplace
- ☐ Air Conditioner

Where do you require service?
Postal Code
OR
Select Service Area
Select municipality

Check for contractors

Contractor Selection & Contact Information 2.0

List of contractors referred.
Deselect any not wanted.
- ☐ Contractor 1
  name/ address/URL/
  telephone-after hours
- ☐ Contractor 2
  name/ address /URL/
  telephone-after hours
- ☐ Contractor 3
  name/ address /URL/
  telephone-after hours

Contact Information
Contact: name
(if business) Business: name
Address
Contact telephone: dayalt phone
Contact email
Terms of Use

Confirmation 3.0

The following contactors will call you within [SLA] days:

Referral Request ID: #xxx-xxx

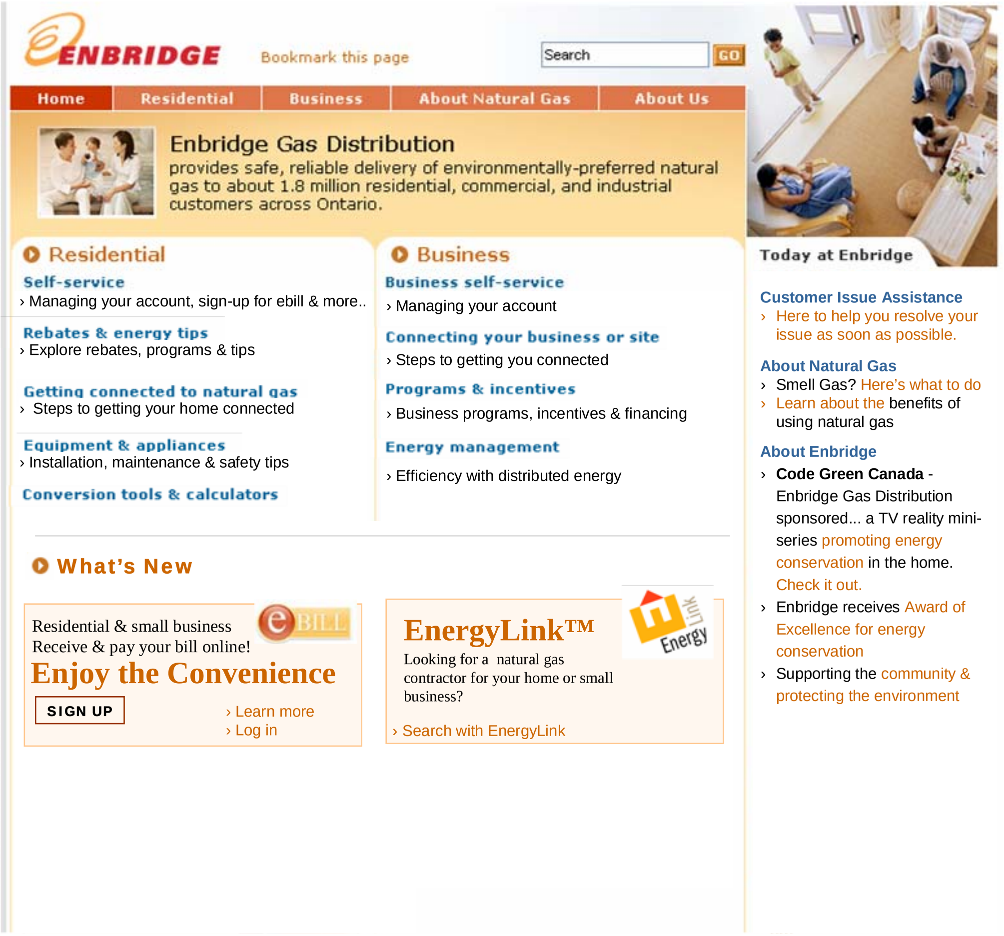
Contractor 1
Contractor 2
Contractor 3

About
[Equipment]

At
[Customer/Service Info]
Print this page

Filed: 2007-02-26
EB-2006-0034
Exhibit J9.3
Attachment 1
Page 3 of 8

Page Title: Home Page
Page ID:



Enbridge Gas Distribution
provides safe, reliable delivery of environmentally-preferred natural gas to about 1.8 million residential, commercial, and industrial customers across Ontario.

Residential

Self-service
› Managing your account, sign-up for ebill & more..

Rebates & energy tips
› Explore rebates, programs & tips

Getting connected to natural gas
› Steps to getting your home connected

Equipment & appliances
› Installation, maintenance & safety tips

Conversion tools & calculators

Business

Business self-service
› Managing your account

Connecting your business or site
› Steps to getting you connected

Programs & incentives
› Business programs, incentives & financing

Energy management
› Efficiency with distributed energy

What's New

Residential & small business
Receive & pay your bill online!
Enjoy the Convenience
SIGN UP
› Learn more
› Log in

EnergyLink™
Looking for a natural gas contractor for your home or small business?
› Search with EnergyLink

Today at Enbridge

Customer Issue Assistance
› Here to help you resolve your issue as soon as possible.

About Natural Gas
› Smell Gas? Here's what to do
› Learn about the benefits of using natural gas

About Enbridge
› **Code Green Canada** - Enbridge Gas Distribution sponsored... a TV reality mini-series promoting energy conservation in the home. Check it out.
› Enbridge receives Award of Excellence for energy conservation
› Supporting the community & protecting the environment

Page Title: EnergyLink Landing/Marketing Page
Page ID:

EnergyLink™

EnergyLink™ makes it easy to get the natural gas energy solutions you need, when you need, with the assurance that EnergyLink contractors and retailers have been pre-screened by Enbridge Gas Distribution.

Why You Can Rely on EnergyLink

① **Approved Contractors**
Pre-screened by Enbridge & recognized trade associations

② **No More Guesswork**
With a professional quote from EnergyLink™ Contractors

③ **Energy Experts**
Providing reliable, quality solutions with NG and related products

How to Get the Information You Want

Submit a request online
and get a call within 24hrs

Call
1 888 285-4427
EnergyLink representatives

Learn More
About Industry Associations

How does the program work

Enbridge has developed the EnergyLink program to help customers like you find qualified energy contractors and retailers you can trust.

EnergyLink contractors and retailers are independent organizations who have been pre-screened by Enbridge, in partnership with recognized trade associations using industry standards. Energylink participants do not pay a fee to belong to this service.

When you contact Energylink you can be assured of finding an independent, fully qualified contractor in your area knowledgeable on our rebates.

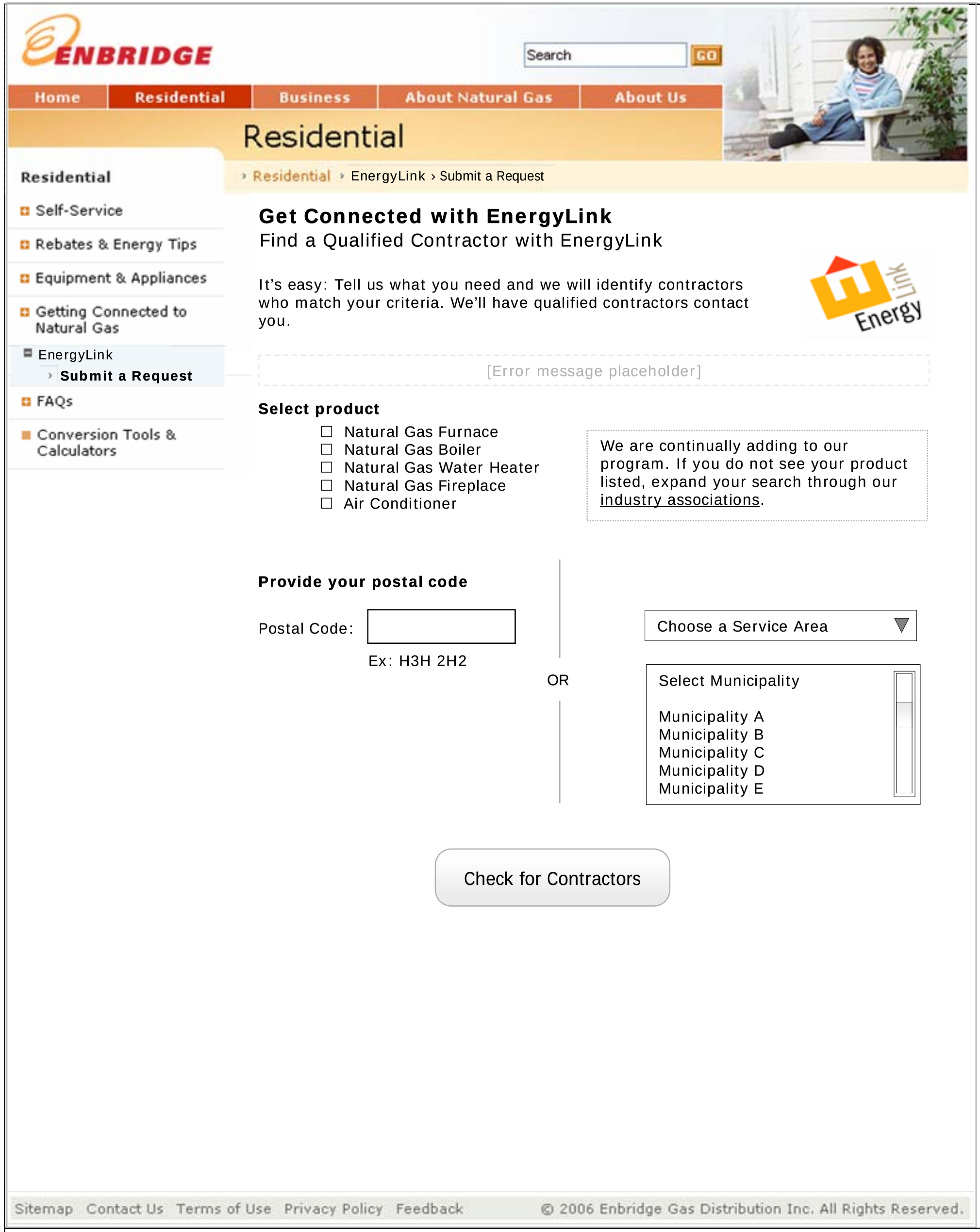
See if your contractor is a member of EnergyLink
View members lists

Industry Associations

800

1024

Page Title: EnergyLink Referral Form Start Page (Page 1)
Page ID: Screen 1.0



Residential

› Residential › EnergyLink › Submit a Request

Get Connected with EnergyLink
Find a Qualified Contractor with EnergyLink

It's easy: Tell us what you need and we will identify contractors who match your criteria. We'll have qualified contractors contact you.

[Error message placeholder]

Select product

- ☐ Natural Gas Furnace
- ☐ Natural Gas Boiler
- ☐ Natural Gas Water Heater
- ☐ Natural Gas Fireplace
- ☐ Air Conditioner

We are continually adding to our program. If you do not see your product listed, expand your search through our industry associations.

Provide your postal code

Postal Code: ______
Ex: H3H 2H2

OR

Choose a Service Area ▼

Select Municipality
Municipality A
Municipality B
Municipality C
Municipality D
Municipality E

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Customer Messaging

"Sorry we have no [contractors] that can service your request. Try again if you have selected more than 1 equipment type."

"Sorry we have no contractors in your area, expand your search with HRAC contractor locator"

800

1024

Filed: 2007-02-26
EB-2006-0034
Exhibit J9.3
Attachment 1
Page 6 of 8

Page Title: Contractor Selection and Contact Information
Page ID: Screen 2.0

EnergyLink
Select Your Contractors

Select the contractors that you would like to hear from, fill in your contact information and click submit. The contractor you select will contact you within 24 hours

☐ **Biss Environmental Systems / 1027188 Ontario Inc**
3775 Dundas Street West
Toronto,ON M6S 2T4

Phone: (416) 760-8658 **Evening:** (416) 760-8126
Website: www.bissenviromnenal.ca

☐ **Catherine Heating**
111 Ridelle Avenue, # 202
Toronto,ON M6B 1J7

Phone: (416) 270-0275
Website: www.catherinesite.com

☐ **Arrow Heating & Air Conditioning Ltd.**
2700 Dufferin Street, Unit #25
Toronto,ON M6B 4J3

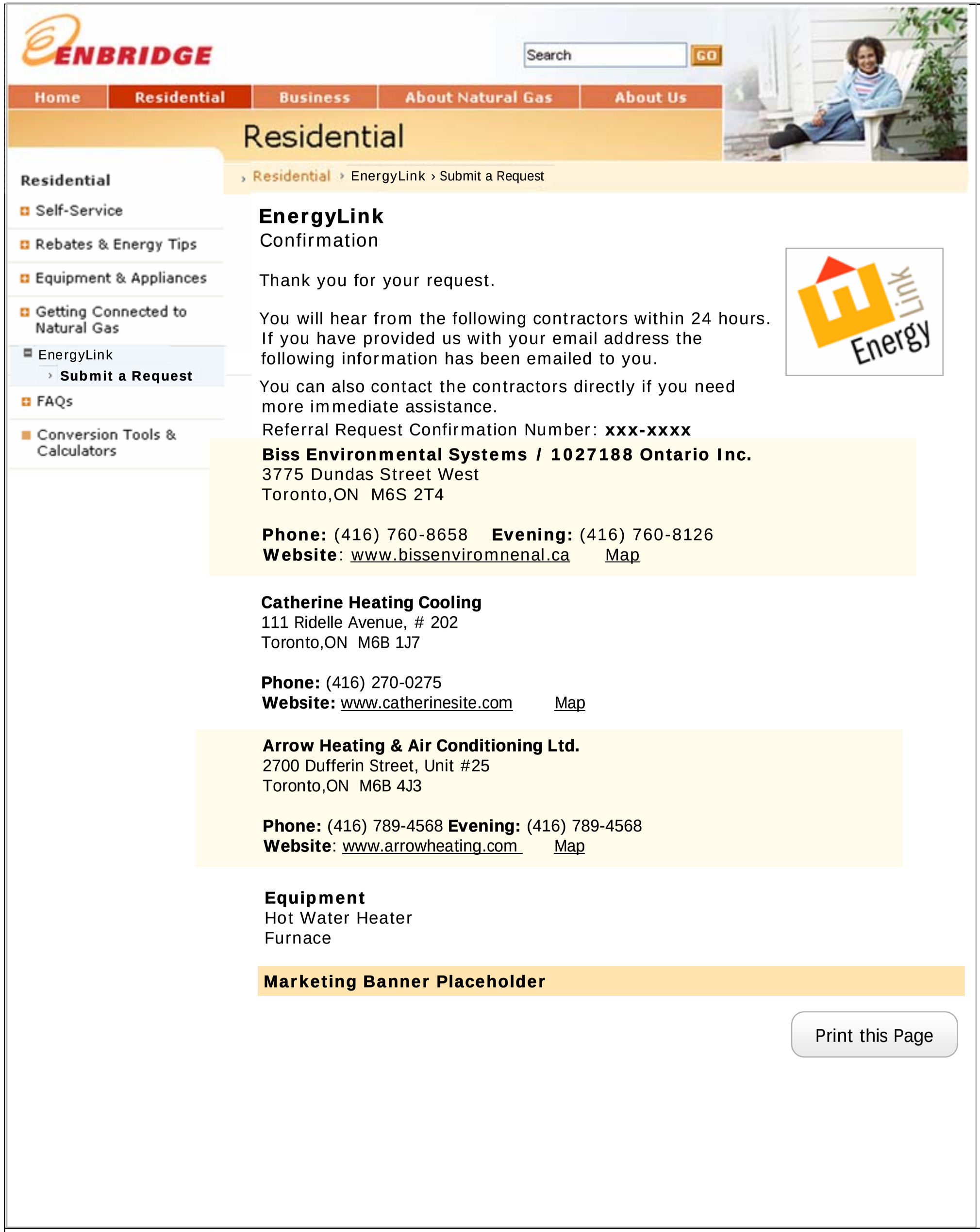
Phone: (416) 789-4568 **Evening:** (416) 789-4568
Website: www.arrowheating.com Map

Contact Information

First Name / Business Name:
Last Name:
Address: Apt. /Suite:
City / Town: [prefilled if supplied] * Province: ON
Postal Code: [prefilled if supplied]
Phone: ( ) ext:
Alt. Phone: ( ) ext:
Email:

☐ I have read and agree to the Terms of use

Submit Clear



EnergyLink
Confirmation

Thank you for your request.

You will hear from the following contractors within 24 hours. If you have provided us with your email address the following information has been emailed to you.

You can also contact the contractors directly if you need more immediate assistance.

Referral Request Confirmation Number: **xxx-xxxx**

Biss Environmental Systems / 1027188 Ontario Inc.
3775 Dundas Street West
Toronto,ON M6S 2T4

Phone: (416) 760-8658 **Evening:** (416) 760-8126
Website: www.bissenviromnenal.ca Map

Catherine Heating Cooling
111 Ridelle Avenue, # 202
Toronto,ON M6B 1J7

Phone: (416) 270-0275
Website: www.catherinesite.com Map

Arrow Heating & Air Conditioning Ltd.
2700 Dufferin Street, Unit #25
Toronto,ON M6B 4J3

Phone: (416) 789-4568 **Evening:** (416) 789-4568
Website: www.arrowheating.com Map

Equipment
Hot Water Heater
Furnace

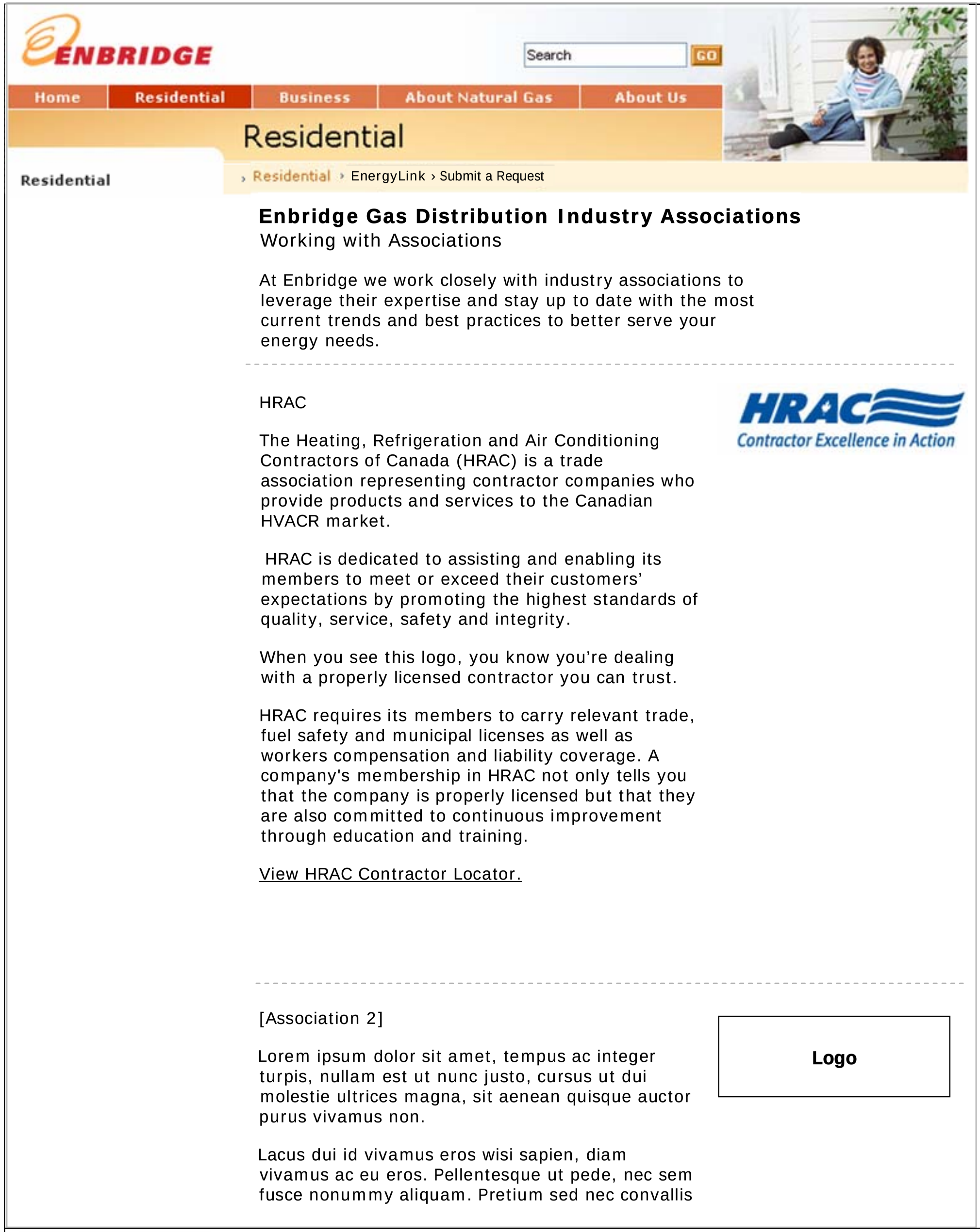
Marketing Banner Placeholder

Print this Page

Page Title: Print Page
Page ID: Screen 3.0

Printing

Page designed to be printed either from in-page print button or browser print function.



Enbridge Gas Distribution Industry Associations
Working with Associations

At Enbridge we work closely with industry associations to leverage their expertise and stay up to date with the most current trends and best practices to better serve your energy needs.

HRAC

The Heating, Refrigeration and Air Conditioning Contractors of Canada (HRAC) is a trade association representing contractor companies who provide products and services to the Canadian HVACR market.

HRAC is dedicated to assisting and enabling its members to meet or exceed their customers' expectations by promoting the highest standards of quality, service, safety and integrity.

When you see this logo, you know you're dealing with a properly licensed contractor you can trust.

HRAC requires its members to carry relevant trade, fuel safety and municipal licenses as well as workers compensation and liability coverage. A company's membership in HRAC not only tells you that the company is properly licensed but that they are also committed to continuous improvement through education and training.

View HRAC Contractor Locator.

[Association 2]

Lorem ipsum dolor sit amet, tempus ac integer turpis, nullam est ut nunc justo, cursus ut dui molestie ultrices magna, sit aenean quisque auctor purus vivamus non.

Lacus dui id vivamus eros wisi sapien, diam vivamus ac eu eros. Pellentesque ut pede, nec sem fusce nonummy aliquam. Pretium sed nec convallis

Page Title: Industry Associations
Page ID:

Printing

Page designed to be printed either from in-page print button or browser print function.

UNDERTAKING J9.5

UNDERTAKING

Tr: 161

To file the formula to determine whether the company passes the sound financial health test

RESPONSE

The formula and scale used to determine whether an applicant passes the financial health criteria for the EnergyLink^{TM} program is as follows:

Risk score = Credit Information Score + Payment Index

The Credit Information (C.I.) Score is a commercially available standardized credit rating. It provides an indication of financial risk. The degree of risk becomes less and less as the score approaches zero. Zero is a perfect score. Conversely, a company with a higher C.I. score carries a higher degree of risk.

The Payment Index is also a commercially available standardized score which reflects the average number of days a company's bills have been past due.

Risk Score	
>81	Declined
51-80	Accept with credit review repeated in 6 months
<51	Accept

The Company intends to repeat credit reviews at membership renewal.

Witnesses: W. Cain
P. Green
K. Lakatos-Hayward
S. McGill

UNDERTAKING J9.6

UNDERTAKING

Tr: 177

Provide number of contractors who ticked boxes for each of the nine products not currently included in the project

RESPONSE

Product	**# of Contractors**
BBQ	121
Ranges	83
Campfires	68
Lamps	46
Dryers	83
Patio Heaters	90
Garage Heater	121
Pool Heaters	111
Indoor Air Quality Products	170

Witnesses: W. Cain
P. Green
K. Lakatos-Hayward
S. McGill

UNDERTAKING J10.1

UNDERTAKING

Tr: 37

Provide number of calls received by EnergyLink^{TM} for gas water heaters, to purchase gas water heaters.

RESPONSE

Initial call requests do not always match the actual job completion result. For example, a customer may request equipment repair, however, their equipment may in fact be beyond repair. Similarly, they may request new equipment, but may find upon assessment by a trained technician, that they can repair their equipment. Since the program launched in December 2006, there were 271 customers who contacted us to request contractors to call them regarding a water heater purchase. In addition, 376 customers contacted us to request a contractor call them regarding a water heater rental.

Witnesses: W. Cain
P. Green
K. Lakatos-Hayward
S. McGill

UNDERTAKING J10.2

UNDERTAKING

TR: 45

Provide from current referrals how many have resulted in customer switching out a non-gas furnace and buying new gas furnace.

RESPONSE

To date, 39 new furnaces have been installed by EnergyLink^{TM} contractors. Having only launched in December of 2006 with a soft launch (i.e., no public media launch), these initial results are very early in this new program. Additionally, contractor participants are still getting familiar with the program and the reporting of results. As such, while we continue training efforts on the system, we will not yet have full data on the proportion of furnaces that are conversions from other fuel sources.

In general, it is anticipated that overall EnergyLink^{TM} results will have a high degree of seasonality. For example, it is anticipated that furnace calls will spike in October and early November, and demand for backyard products will likely spike in spring and early summer. For the aforementioned reasons, these initial results to date cannot be extrapolated over the year.

Witnesses: W. Cain
P. Green
K. Lakatos-Hayward
S. McGill

Filed: 2007-02-26
EB-2006-0034
Exhibit J10.3
Page 1 of 1

UNDERTAKING J10.3

UNDERTAKING

Tr: 47

To provide a monthly projection, if available, of number of calls expected to EnergyLink^{TM} in 2007.

RESPONSE

Attached are the projected sales calls for EnergyLink^{TM} Program in 2007. As this is the first year of operation we will continue to monitor the number of calls handled and revise our forecast accordingly.

EnergyLink Actual/Forecasted Calls

Year	Month	Call Volume
2006	December (5-21)	970
2007	January	2892
	February	3950
	March	3800
	April	3600
	May	3800
	June	4200
	July	4200
	August	3800
	September	3900
	October	4300
	November	4100
	December	4300
Total		**47,812**

Witnesses: W. Cain
P. Green
K. Lakatos-Hayward
S. McGill

Filed: 2007-02-26
EB-2006-0034
Exhibit J10.5
Page 1 of 1

UNDERTAKING J10.5

UNDERTAKING

Tr: 84

Provide dollar amount spent advertising EnergyLink^{TM} to date and projected for 2007.

RESPONSE

The amount spent year-to-date for EnergyLink^{TM} program advertising is $0.3 million. The total projected amount for 2007 is $0.6 million and is subject to the Company's allocation of the recently settled and approved O&M budget for 2007, and the Board's decision related to EnergyLink^{TM}.

Witnesses: W. Cain
P. Green
K. Lakatos-Hayward
S. McGill

Filed: 2007-02-26
EB-2006-0034
Exhibit J10.6

UNDERTAKING J10.6

UNDERTAKING

Tr: 125

To provide percentage of expenditures for co-op advertising.

RESPONSE

Expenditures available for co-op advertising are highly dependent on the available budget year-to-year as this cost category is discretionary. Based on a base O&M budget (before overheads) of $1.036M, a maximum of 5% or $50,000 would be allocated to co-op advertising.

Witnesses: W. Cain
P. Green
K. Lakatos-Hayward
S. McGill

UNDERTAKING J10.7

UNDERTAKING

Tr: 126

To provide a spreadsheet showing in detail how forecasted volumes of 8 million cubic metres in year one, and the forecasted participants, were arrived at.

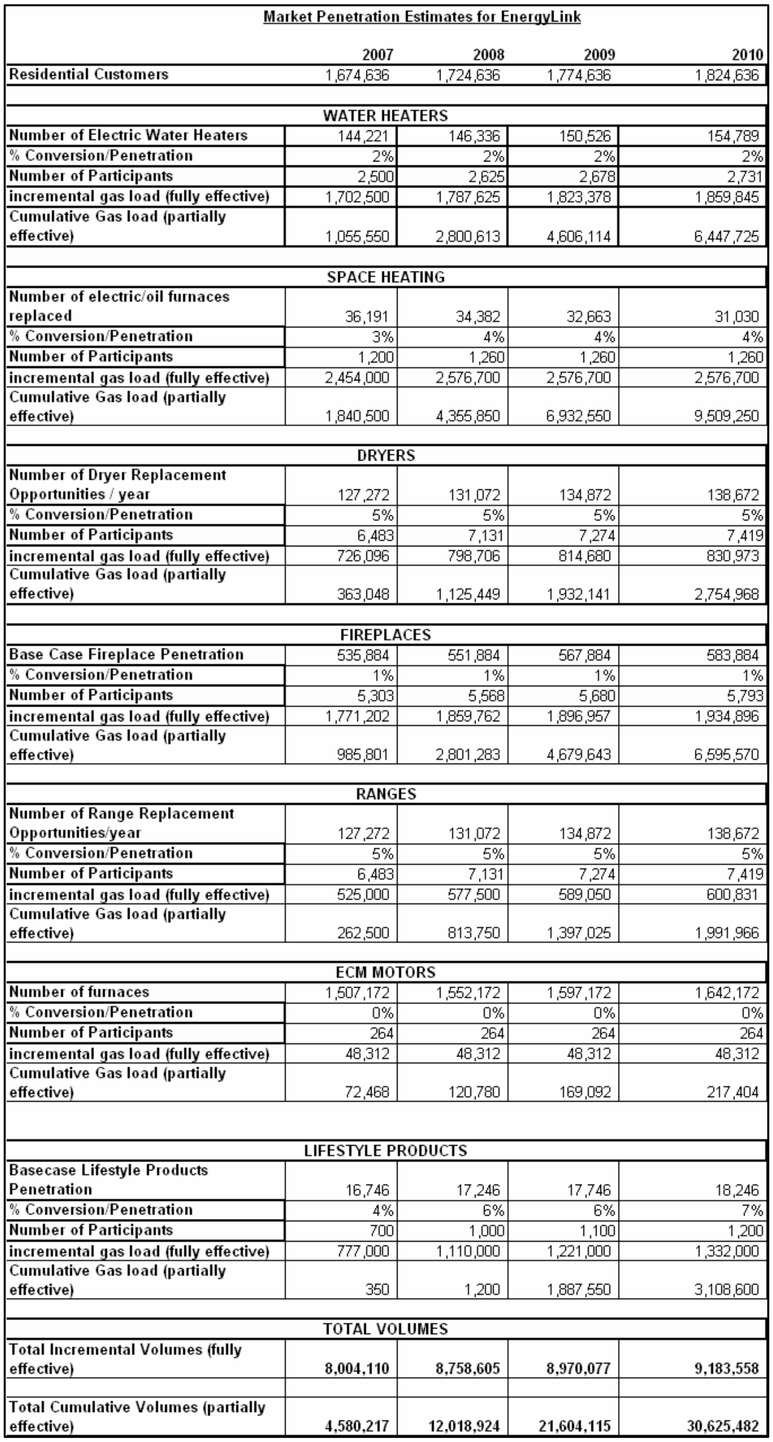
RESPONSE

The EnergyLink^{TM} program is a channel development program that is designed to reduce barriers to purchasing and installing natural gas appliance products for customers. The program will transform the market over time, connecting customers with qualified providers of natural gas appliance products and also creating greater consumer awareness of the benefits of natural gas.

The market penetration and associated volumetric assumptions regarding the program are attached in Table One.

Witnesses: W. Cain
P. Green
K. Lakatos-Hayward
S. McGill

TABLE ONE
ENERGYLINK MARKET PENETRATION AND VOLUMETRIC ASSUMPTIONS



Market Penetration Estimates for EnergyLink

	2007	2008	2009	2010
Residential Customers	1,674,636	1,724,636	1,774,636	1,824,636
WATER HEATERS				
Number of Electric Water Heaters	144,221	146,336	150,526	154,789
% Conversion/Penetration	2%	2%	2%	2%
Number of Participants	2,500	2,625	2,678	2,731
incremental gas load (fully effective)	1,702,500	1,787,625	1,823,378	1,859,845
Cumulative Gas load (partially effective)	1,055,550	2,800,613	4,606,114	6,447,725
SPACE HEATING				
Number of electric/oil furnaces replaced	36,191	34,382	32,663	31,030
% Conversion/Penetration	3%	4%	4%	4%
Number of Participants	1,200	1,260	1,260	1,260
incremental gas load (fully effective)	2,454,000	2,576,700	2,576,700	2,576,700
Cumulative Gas load (partially effective)	1,840,500	4,355,850	6,932,550	9,509,250
DRYERS				
Number of Dryer Replacement Opportunities / year	127,272	131,072	134,872	138,672
% Conversion/Penetration	5%	5%	5%	5%
Number of Participants	6,483	7,131	7,274	7,419
incremental gas load (fully effective)	726,096	798,706	814,680	830,973
Cumulative Gas load (partially effective)	363,048	1,125,449	1,932,141	2,754,968
FIREPLACES				
Base Case Fireplace Penetration	535,884	551,884	567,884	583,884
% Conversion/Penetration	1%	1%	1%	1%
Number of Participants	5,303	5,568	5,680	5,793
incremental gas load (fully effective)	1,771,202	1,859,762	1,896,957	1,934,896
Cumulative Gas load (partially effective)	985,801	2,801,283	4,679,643	6,595,570
RANGES				
Number of Range Replacement Opportunities/year	127,272	131,072	134,872	138,672
% Conversion/Penetration	5%	5%	5%	5%
Number of Participants	6,483	7,131	7,274	7,419
incremental gas load (fully effective)	525,000	577,500	589,050	600,831
Cumulative Gas load (partially effective)	262,500	813,750	1,397,025	1,991,966
ECM MOTORS				
Number of furnaces	1,507,172	1,552,172	1,597,172	1,642,172
% Conversion/Penetration	0%	0%	0%	0%
Number of Participants	264	264	264	264
incremental gas load (fully effective)	48,312	48,312	48,312	48,312
Cumulative Gas load (partially effective)	72,468	120,780	169,092	217,404
LIFESTYLE PRODUCTS				
Basecase Lifestyle Products Penetration	16,746	17,246	17,746	18,246
% Conversion/Penetration	4%	6%	6%	7%
Number of Participants	700	1,000	1,100	1,200
incremental gas load (fully effective)	777,000	1,110,000	1,221,000	1,332,000
Cumulative Gas load (partially effective)	350	1,200	1,887,550	3,108,600
TOTAL VOLUMES				
Total Incremental Volumes (fully effective)	**8,004,110**	**8,758,605**	**8,970,077**	**9,183,558**
Total Cumulative Volumes (partially effective)	**4,580,217**	**12,018,924**	**21,604,115**	**30,625,482**

Witnesses: W. Cain
P. Green
K. Lakatos-Hayward
S. McGill

Filed: 2007-02-26
EB-2006-0034
Exhibit J10.8

UNDERTAKING J10.8

UNDERTAKING

Tr: 126

To advise how many calls to date of the 1,770 referrals were from non-customers on main.

RESPONSE

Of the 1,770 referrals approximately 5% were from non-customers on main.

Witnesses	W. Cain P. Green K. Lakatos-Hayward S. McGill

UNDERTAKING J10.9

UNDERTAKING

Tr: 155

To check for a written submission by Enbridge Gas Distribution to either Enbridge Solutions or Enbridge Inc. regarding providing financing for the EnergyLink program.

RESPONSE

Chronology

In the Summer of 2005, numerous discussions with held with EGD sales staff, key contractors, as well as members of HRAI regarding the importance of making on bill financing accessible as part of any formalized channel partner strategy to grow natural gas load. At the same time, EGD was working with ABSU to determine the scope and cost associated with making changes to CIS to accommodate on bill financing. The estimate from ABSU was $3.5 Million. In the 2006 rate case, the Company testified that it likely was not feasible to make this investment, given that the CIS was anticipated to be replaced in 18 months. The Company also testified that it was investigating alternative bill financing options, including the possibility of working with an external provider to send out a secondary Enbridge bill that did not contain the gas distribution charges. Through the Fall of 2005, Enbridge continued to investigate all options to facilitate bill access and to assess the feasibility of making the requisite system changes. This effort culminated with a presentation in December 2005 to justify proceeding with a financing program to support EnergyLink^{TM}. The plan was prepared by Kerry Lakatos-Hayward and Erika Lontoc of EGD and Olga Shpora-Odell of EI and was presented to Scott Player and Lino Luison of EGD and Will Akkermans of EDMSI (the predecessor company to Enbridge Solutions Inc.). Subsequent to this meeting, a decision was made to move the financing initiative to EDMSI, wherein a full time EDMSI employee, Darren McIlwraith was hired in February 2006 to continue development of this initiative. After this juncture, EGD staff was not involved with the financing initiative. It should also be noted that in February 2006, the 2006 rate case decision was received. It clarified that billing services were a regulated service and that the Company needed to bring forward a comprehensive proposal for open access to the bill as part of its 2007 rate application.

Approvals for the EnergyLink^{TM} program were made separately by the EnergyLink^{TM} Executive Committee comprised of EGD senior management. Approvals for proceeding with the capital investment for EnergyLink were made in May 2006 following a package evaluation for the EnergyLink™ referral system. The EnergyLink™ program was launched in December 2006 without any financing initiative accompanying the program. Additionally, we have been advised by Enbridge Solutions Inc. that as of February 2007 final approvals had not been received to proceed with the financing program.

Attached is the December 18th, 2005 presentation. It presented the scope, supporting market research, initial financial analysis and various options for partnerships and billing. A comparison of this presentation with the EFS Summary document Exhibit KX10.2 shows that the partnership arrangements and structure are quite different than the initial options presented.

Exhibit J10.9, Attachment 1, page 4 highlights the scope of the proposed financing program:

- Provide Enbridge residential and small customers with a convenient, seamless and competitively priced financing option to facilitate the purchase of natural gas appliances as well as complementary products

- Support Enbridge Gas Distribution's Contractor Partners by providing access to the EGD bill. Access to the bill will primarily be through a consumer financing product, but may also include bill marketing opportunities

The plan assumed a modest program uptake of 4% of financing opportunities available, demonstrating that Enbridge Inc.'s program would be only one of many payment options available to contractors and customers.

Enbridge Gas Distribution encourages Enbridge Solution Inc.'s plans to bring to market an equipment financing program for contractors and other providers of natural gas appliances, as more competitively financed options will facilitate the purchase of natural gas appliances. However, the Company has made it very clear to Enbridge Solutions Inc. and Enbridge Inc. that EGD cannot and will not endorse any particular financing company, and will adhere to the requirements of ARC.

Witnesses: W. Cain
P. Green
K. Lakatos-Hayward
S. McGill

Enbridge Consumer Financing Project - Update

ENBRIDGE

December 18, 2005

Summary

- **Strong financial business case for on bill financing**
  - 10 year equity NPV of $19.1M
  - 10-year discounted earnings stream of $43.7M
- **Consumer financing opportunity provides critical strategic fit for Enbridge Gas Distribution**
  - Increase penetration of additional gas appliances and improve control over external distribution channels.
  - Overall success of Atocha's Strategic Contractor Channel Partnership Program is heavily dependent on being able to provide contractors with access to the bill
  - Supports overall bill strategy by driving traffic to the bill
  - Provides ratepayer benefit by increasing number of shared bills
  - Offering could increase uptake on e-bill

Summary

- Project Risks
  - Technical risk: Requires changes to the existing CIS to add receivable types and to add new accounting & control functionality
  - Legal risk: any option requiring Enbridge / ABSU to perform collections & call centre activity requires changes to a number of legal agreements, however we believe this will not involve the Trust agreement.
  - Regulatory risk: issues 9.19 OEB could dictate future rules of the game regarding billing of EGD distribution charges
  - Partner risk: Requires successful negotiation with 3rd party vendor.
- 2005/6 cash flow requirements on average $10.7M
  - Includes $5.7M start up costs and $5M average working capital
- Project at the stage where need to add additional FTE resource

Scope

- Provide Enbridge residential and small customers with a convenient, seamless and competitively priced financing option to facilitate the purchase of natural gas appliances as well as complementary products
- Support Enbridge Gas Distribution’s Contractor Partners by providing access to the EGD bill. Access to the bill will primarily be through a consumer financing product, but may also include bill marketing opportunities

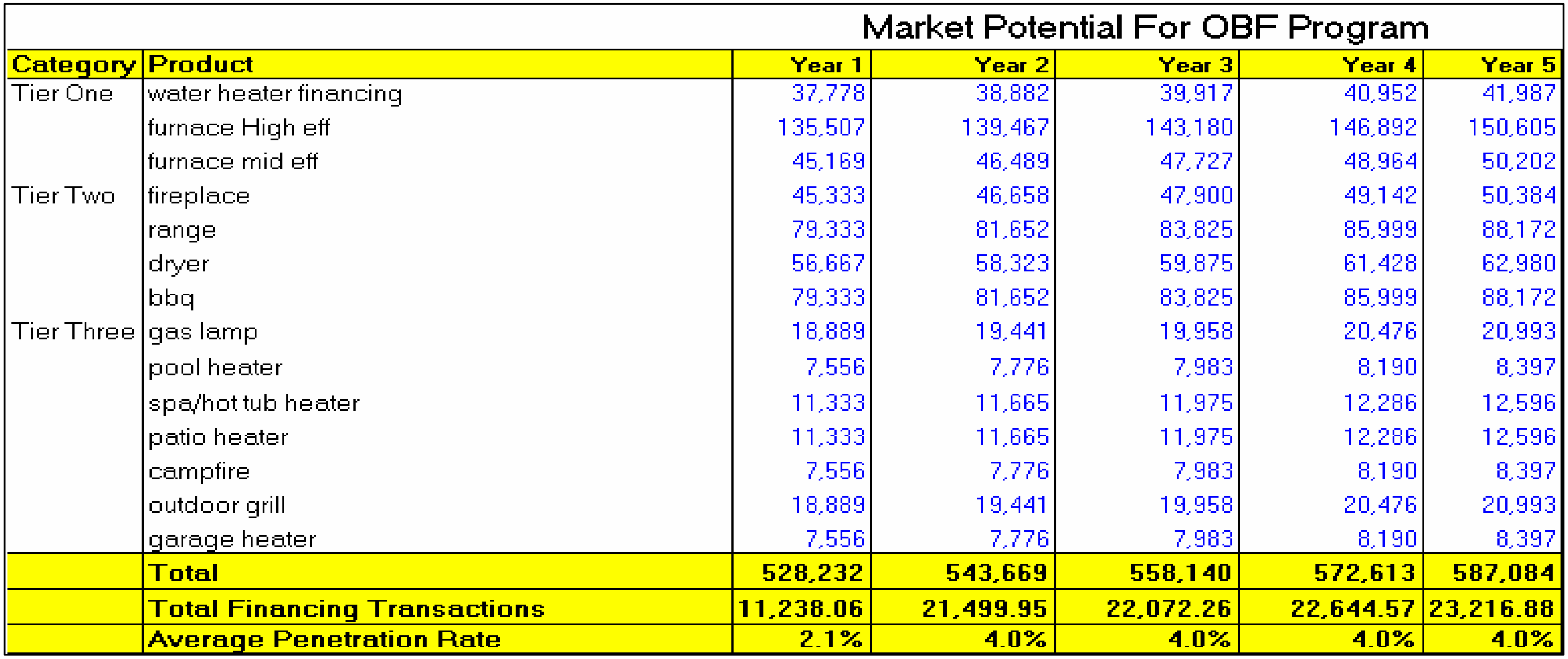
Customer Research Findings

- 10% of customers to buy NG appliances next year
  - 23% somewhat likely to buy NG appliances next year
  - Furnace, stove, BBQ, dryer, fireplace get most mentions
- 15% of customers would look to purchase from EGD
  - 3rd highest ranking after Sears/Home Depot, no mention of DE
  - Cost, service quality, reputation of brand most important
- 14% customers very interested in on-bill financing
  - Furnace, WH, Range, BBQ and lifestyle products most mentions
  - Interest rates, cost/savings/discounts key motivators
- Customers are more interest rate sensitive than in past
  - Threshold level is below 20% (and closer to 15%)
- 37% of customers would use an on-line NG appliance catalogue if offered through an Enbridge portal
- 7% would buy appliances on line
- 20% of customers would select a contractor on-line

Implications of the Research

- Enbridge enjoys high recognition/receptivity by customers as a place to "purchase" natural gas products
- Atocha's channel strategy would create a strong push for successful delivery of a financing offer
- However, Enbridge financing offer must be competitively priced below 20% and closer to 15%
  - Current business case assumes an effective interest rate of 18%

Annual Market Potential Estimates for Product Financing



Market Potential For OBF Program

Category	Product	Year 1	Year 2	Year 3	Year 4	Year 5
Tier One	water heater financing	37,778	38,882	39,917	40,952	41,987
	furnace High eff	135,507	139,467	143,180	146,892	150,605
	furnace mid eff	45,169	46,489	47,727	48,964	50,202
Tier Two	fireplace	45,333	46,658	47,900	49,142	50,384
	range	79,333	81,652	83,825	85,999	88,172
	dryer	56,667	58,323	59,875	61,428	62,980
	bbq	79,333	81,652	83,825	85,999	88,172
Tier Three	gas lamp	18,889	19,441	19,958	20,476	20,993
	pool heater	7,556	7,776	7,983	8,190	8,397
	spa/hot tub heater	11,333	11,665	11,975	12,286	12,596
	patio heater	11,333	11,665	11,975	12,286	12,596
	campfire	7,556	7,776	7,983	8,190	8,397
	outdoor grill	18,889	19,441	19,958	20,476	20,993
	garage heater	7,556	7,776	7,983	8,190	8,397
	Total	**528,232**	**543,669**	**558,140**	**572,613**	**587,084**
	Total Financing Transactions	**11,238.06**	**21,499.95**	**22,072.26**	**22,644.57**	**23,216.88**
	Average Penetration Rate	**2.1%**	**4.0%**	**4.0%**	**4.0%**	**4.0%**

Based on appliance purchase intentions from the July 2005 OBF research

Out of this potential 11.200 (2.1%) of customers will select OBF in year 1 increasing to 21,449 in year 5 (4.0%)

Financing Transaction Penetration Estimates

ENBRIDGE

Number of annual transactions	Average Principal Value	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6
water heater financing	$1,019	1,133	2,333	2,395	2,457	2,519	2,519
furnace high eff	$5,021	4,065	8,368	8,591	8,814	9,036	9,036
furnace a/c combo	$9,450	1,355	2,789	2,864	2,938	3,012	3,012
fireplace	$3,350	227	467	479	491	504	504
range	$2,250	1190	2450	2515	2580	2645	2645
dryer	$1,150	850	1750	1796	1843	1889	1889
bbq	$750	1,587	1,633	1,677	1,720	1,763	1,763
gas lamp	$1,100	378	778	798	819	840	840
pool heater	$1,750	227	467	479	491	504	504
spa hot tub heater	$1,000	226.67	466.58	479.00	491.42	503.84	503.84
patio heater	$1,000	0.00	0.00	0.00	0.00	0.00	0.00
Total	$2,405	11,238	21,500	22,072	22,645	23,217	23,217

Average transaction size ~ $2,405 Highest $9,450 for furnace/Air conditioning combo and smallest <$1,000 for BBQ

Furnaces and water heaters generate most interest followed by range, BBQ and dryer

Business Model Description

Enbridge provides on-bill financing directly via the existing natural gas bill

- (I) EGD provides recourse to 3rd party financing, receivables & cash management, as well as customer care services to contractors, retailers and financing partners
- (II) EGD assumes bad debt risk (assumed 2% p.a.)
- (III) EGD’s cost is recovered through an up-front fee paid by the financing company (based on the difference between an effective 18% annual percentage of rate charged to the customer and the cost of debt (5 year bond rate +4.75%)
- (IV) 5-year contract with capability to defer payments
- (V) Requires early launch of a new CIS module that would calculate payments and “house” all billing details including new receivable types; billing transactions are merged in the existing CIS transactions for bill production
  - (I) Modification of existing CIS ~ $2.9+

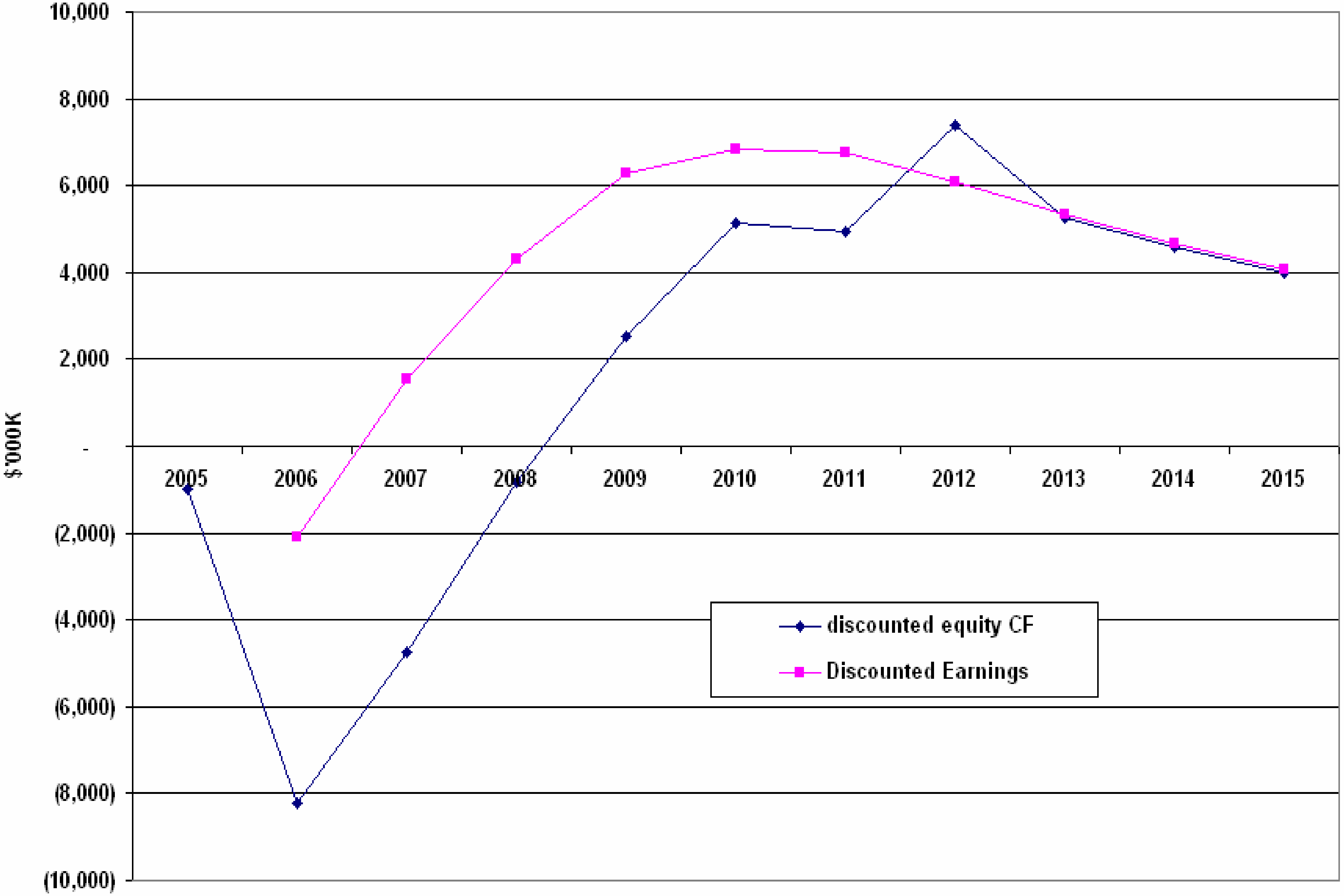
Financial Assumptions

- Horizon 2006-2015
- 2012-2015 assume that revenues are flat
- Provision for capital reserve to provide protection to FINCO from potential ENB default.
- Capital Reserve of 15% used.
- Capital reserve and working capital are financed by shareholders
- Loans are financed by debt on ENB_FIN's balance sheet
- A resulting 85:15% debt equity spread is used
- Annual inflation rate 2%
- Working capital 5 days of revenues
- For year 2006 50% effectivity factor applies

Financial Assumptions

- **Revenue ranges between $3.5M in year 1 to $45.6M by the end of the project**
- **Annual bad debt expense is estimated as 2% of the average loan asset of $38.4-216M over the ten year horizon**
- **Project cost includes**
  - $2.9M to cover the changes to CIS, out of which $.963M is expensed and $1.9M capitalized
  - Customer care cost per customer declines over the life of the project: $60-20/customer
  - $1.5M in legal fees is expensed for both tax and accounting purposes
  - $500K+ on-going marketing expenses
- **Equity Cash Flow NPV $19.1M**
- **10 Year Discounted Earnings of $43.7**

OBF PROGRAM - ANNUAL EARNINGS AND CASH FLOW



Financial Scenario 1: Equity NPV Results Under Varying Cost of Debt Assumptions

Financial Scenarios

	Cost of Debt		
	7%	9%	10%
Equity NPV	$ 30,615	$ 20,697	$ 15,722
IRR	45%	35%	30%
Average Interest Payments	$ 11,780	$ 15,146	$ 16,829
Average Net Income	$ 11,557	$ 9,407	$ 8,332

Interest Rate 18%

Financial Scenario 2: Equity NPV Results Under Varying Interest Rate Assumptions

Financial Scenarios

	Interest		
	18%	17%	16%
Equity NPV	$ 30,615	$ 25,129	$ 19,670
IRR	45%	40%	35%
Average Revenues	$ 35,174	$ 33,066	$ 30,979
Average Net Income	$ 11,557	$ 10,266	$ 8,990

Debt Cost is 7%, Equity Cost 15%

Financial Scenario 3: Breakeven Equity NPV Results Under Varying Assumptions

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Financial Scenarios

Debt Cost	Interest Rates	Penetration Rates	
		Furnaces	Water Heaters
10%	18%	1.50%	1.50%
7%	18%	0.60%	0.60%
10%	16%	3.50%	3.50%
7%	16%	1.30%	1.30%

Pros of Cons of On-Bill Financing Versus a Private Brand Label Financing Program

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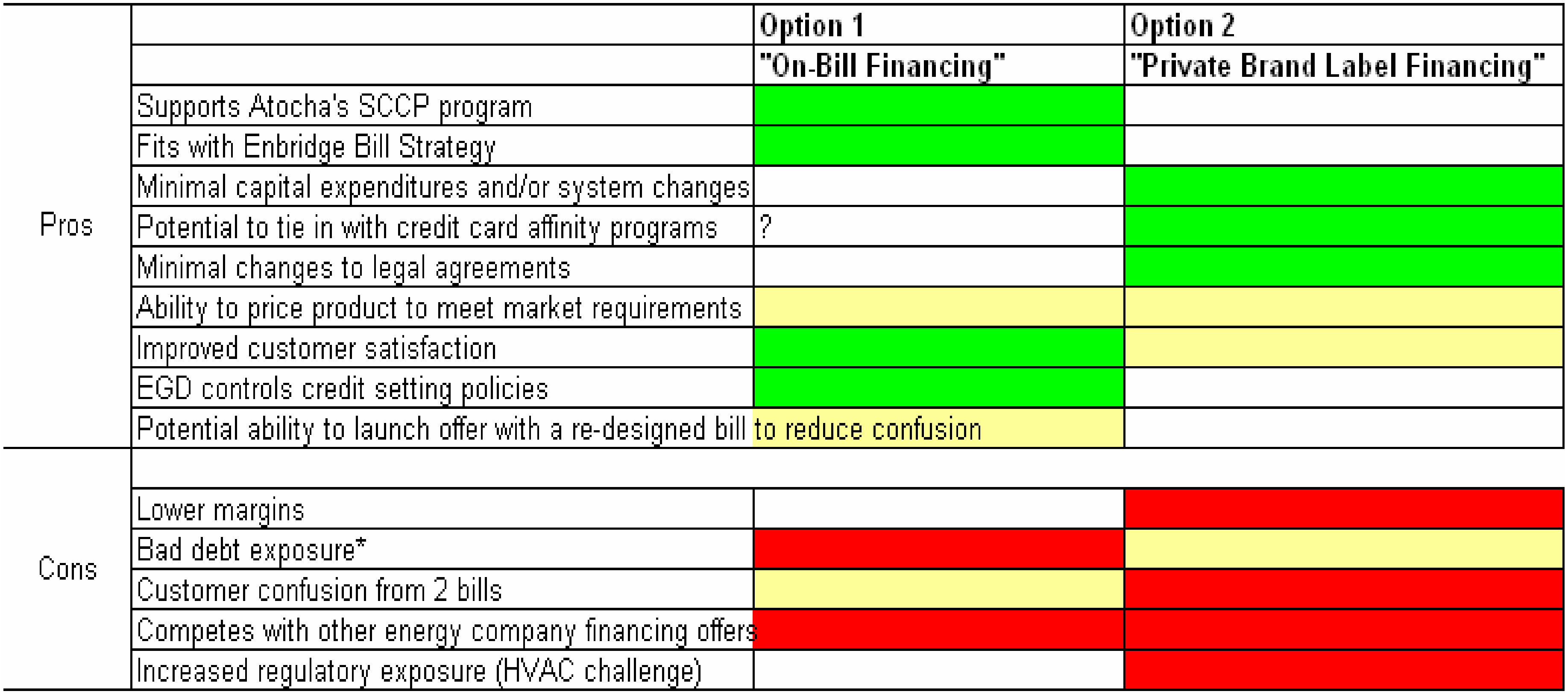
Pros/Cons of Each Option



		Option 1 "On-Bill Financing"	Option 2 "Private Brand Label Financing"
Pros	Supports Atocha's SCCP program	🟩	
	Fits with Enbridge Bill Strategy	🟩	
	Minimal capital expenditures and/or system changes		🟩
	Potential to tie in with credit card affinity programs	?	🟩
	Minimal changes to legal agreements		🟩
	Ability to price product to meet market requirements	🟨	🟨
	Improved customer satisfaction	🟩	🟨
	EGD controls credit setting policies	🟩	
	Potential ability to launch offer with a re-designed bill to reduce confusion	🟨	
Cons			
	Lower margins		🟥
	Bad debt exposure*	🟥	🟨
	Customer confusion from 2 bills	🟨	🟥
	Competes with other energy company financing offers	🟥	🟥
	Increased regulatory exposure (HVAC challenge)		🟥

Status of Discussions with Financing Vendors

ENBRIDGE

	GE Capital	ING	National Leasing	GHR
Interested in OBF	🟩	🟩 ?	🟩	🟩
Interested in Private Brand	🟩	🟩	🟩	🟩
Interested in Credit Card Option	🟩	🟥 ?	🟥	🟥
Interest rate range	OBF (19.9% but includes merchant fees payable by contractor) Credit card (19.5% with up to 1% cash back rewards)	TBD	9.3% - no merchant fees	TBD
Preliminary discussions held	🟩	🟩	🟩	🟩
NDA	🟩	🟩	🟩	🟩
Offer Received	🟩		🟩	

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EB-2006-0034
Exhibit J11.7
Page 1 of 1

UNDERTAKING J11.7

UNDERTAKING

Tr: 48

To provide the script of any radio ads for the EnergyLink program.

RESPONSE

The script for the EnergyLink™ radio advertisement is as follows:

> Finding a qualified natural gas contractor has just become easier!
>
> Introducing EnergyLink™ from Enbridge Gas Distribution – the new, free link to all your natural gas needs.
>
> EnergyLink™ can refer you to independent natural gas contractors in your area. So there's no more guesswork. Now it's simple to find contractors who are fully qualified to install natural gas products.
>
> For an EnergyLink™ contractor log on to enbridge dot com slash energylink or call One – triple eight – G – A – S – eighty-eight, eighty-eight,
>
> EnergyLink™. Your new link to peace-of-mind.

Witnesses: W. Cain
P. Green
K. Lakatos-Hayward
S. McGill